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Examination of Blowout Preventer Pressure Test Frequency

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Argonne NATIONAL LABORATORY

U.S. DEPARTMENT OF ENERGY

EXAMINATION OF BLOWOUT PREVENTER PRESSURE TEST FREQUENCY

Prepared for the

Bureau of Safety and

Environmental Enforcement

by

Argonne National Laboratory

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Executive Summary

The blowout preventer (BOP) is a vital tool for the prevention and mitigation of loss-of-well control events during offshore drilling operations. Due to its role as an important safety system, the BOP is subjected to both function tests and pressure tests to gauge its adequacy to fulfill its design requirements. Current regulation mandates that BOP pressure tests be performed at least every 14 days while the BOP is installed on the well. This requirement is in conflict with the industry standard (API 53), which has a 21-day requirement. **The goal of the current project was to examine the potential impact of extending the time-based BOP pressure test interval beyond the current 14-day regulatory requirement.**

The current study examined how an extension of the time-based BOP pressure test interval may impact operational economics, operational safety, and component reliability. An overview of the results of this analysis can be found in the table below. In terms of operational economics, there is a significant benefit due to a gross reduction in the amount of rig downtime necessary for BOP pressure tests. Operational safety experiences a similar benefit, as there is a reduction of risks associated with downhole operations, high-pressure rig operations, and the potential for operational errors. An extension of the time-based BOP pressure testing interval appears to have minimal impact on component reliability, as the main component failure mechanisms are event- and condition-dependent rather than time-dependent. This conclusion is based on a qualitative and quantitative assessment of elastomer reliability, described below. **The overall conclusion of the analysis is that an extension of the time-based BOP pressure testing interval offers a significant net benefit.**

	Impact of an Extension of the Time-Based BOP Pressure Test Interval		
Factor	***Operational Economics***	***Operational Safety***	***Component Reliability***
Description	*A significant amount of rig downtime is necessary to prepare for and perform BOP pressure tests, which adds to the costs associated with offshore drilling.*	*BOP pressure testing requires significant downhole and on rig operations and system reconfigurations.*	*The BOP pressure test is primarily a proof test of the following components:* • *BOP wellbore sealing elastomers* • *Choke/kill lines and valves*
Analysis Results	*An economic analysis found average industry wide cost savings over the next ten years of:* • *$410 Mil/year for 21 day* • *$600 Mil/year for 28 day*	*Reduction in risks associated with the following factors:* • *Downhole operations* • *High pressure rig operations* • *Potential for system misalignment*	*A qualitative and quantitative reliability analysis demonstrates that there is minimal net impact on component reliability due to an extension of the time based pressure test interval.*
Conclusion	***Significant Benefit***	***Significant Benefit***	***Minimal Impact***

The current study identified the wellbore-sealing elastomers on the pipe rams, VBRs, and annulars as the main components impacted by a change in the BOP time-based pressure testing interval, as their operational status cannot be ascertained by the weekly function test. Therefore, a multifaceted examination of elastomer reliability was conducted. A qualitative assessment of elastomer failure modes and past elastomer failures demonstrated that the dominant failure mechanisms are not time-on-well-dependent and that failures are routinely identified by pathways other than the time-based BOP pressure test. A quantitative analysis of the probability of elastomer failure on demand was conducted using a reliability model based on available data from the Well Activity Reports (WARs) within the TIMS database and several past BOP studies. Although this data was limited to rigs utilizing a 14-day BOP pressure testing interval, use of the developed reliability model allowed the examination of alternative pressure testing protocols and the determination of the potential change in the probability of elastomer failure. While uncertainties exist regarding the available data (detailed below), the results of the qualitative and quantitative analysis both indicate that an extension of the time-based BOP pressure testing interval has minimal impact on elastomer reliability.

During the current study, three major areas of uncertainty regarding elastomer reliability were identified, outlined in the table below, that impact the study findings and recommendations. One macro uncertainty was recognized regarding the difficulties associated with extracting BOP component reliability data from the WARs and the lack of reliability data sharing in industry. Two additional uncertainties relate to the details associated with wellbore sealing elastomer degradation events and elastomer fatigue. Both of these factors are important for the estimation of wellbore sealing elastomer reliability.

Topic	***Uncertainties Regarding Elastomer Reliability***
Component Reliability Data	*BOP component reliability data is difficult to extract from the Well Activity Reports (WARs) and not routinely shared within industry.*
Elastomer Degradation Events	*Guidance on the avoidance and identification of wellbore events or conditions that can potentially degrade BOP wellbore sealing elastomers is not well defined.*
Elastomer Fatigue	*Current regulation and referenced standards do not have quantitative requirements regarding BOP wellbore sealing elastomer fatigue and data sharing within industry regarding elastomer fatigue is rare.*

Based on the findings of the elastomer reliability analysis, a series of potential actions were formulated, summarized in the table below, which could be utilized to ensure BOP reliability in the event that the BOP pressure testing interval was extended beyond 14 days or a transition was made from a time-based testing interval to a performance-based or risk-informed interval (discussed below). The first series of potential actions relates to improvements of the WAR data to help facilitate future component reliability studies. The next three areas explore equipment qualification, as well as condition-based and performance-based actions that could address the uncertainties regarding elastomer reliability, highlighted above. These actions include items such as following new API standard requirements, establishing acceptable elastomer operating windows, recording elastomer use-cycles and wellbore conditions, and monitoring elastomer performance by trend analysis utilizing digital pressure testing techniques.

Topic	Potential Actions to Address Uncertainties
WAR Data Actions	*Modifications to the Well Activity Report format and database structure to improve reporting consistency and aid in future data mining efforts.*
Equipment Qualification Actions	*Uncertainty regarding elastomer fatigue could be addressed through the adoption of the PR2 level of the 4th edition of API 16A, which has quantitative minimum elastomer performance requirements.*
Condition-Based Actions	*Multiple uncertainties could be addressed through the establishment of an allowable elastomer operating window for each well and the tracking of elastomer cycles, operations, and exposed conditions during time in service.*
Performance-Based Actions	*Multiple uncertainties could be addressed through the use of elastomer performance trend analysis utilizing digital pressure testing and post use elastomer inspection.*

The findings of the current study indicate that there is a potential opportunity to transition from a time-based BOP pressure testing interval to a performance-based or risk-informed protocol. This is due to the nature of the dominant elastomer failure mechanisms, which are not strictly time-on-well-dependent, but are contingent upon operational actions and conditions. For such a program to be instated, uncertainties regarding elastomer degradation events and elastomer fatigue would need to be addressed. The potential actions outlined above offer one possible avenue to providing the necessary confidence for such a transition to occur. In addition, pilot programs utilizing a BOP pressure testing interval beyond 14 days could provide valuable information for validating the reliability models used here and supporting a modification to the pressure testing protocol.

Topic	Project Recommendation
Transition to performance-based or risk-informed BOP pressure test program	*A transition from a time based BOP pressure testing program to a performance based or risk informed program may be possible but is dependent on increased component reliability data collection and improved industry guidance regarding the occurrence of potentially degrading events.*

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ACRONYMS

API	American Petroleum Institute
BHA	Bottom Hole Assembly
BOP	Blowout Preventer
BSEE	Bureau of Safety and Environmental Enforcement
BSR	Blind Shear Ram
CCF	Common Cause Failure
CCR	Circular Chart Recorder
CFR	Code of Federal Regulations
EIA	Energy Information Administration
FOSV	Fully Operating Safety Valves
GoM	Gulf of Mexico
IBOP	Inline Blowout Preventer
LMRP	Lower Marine Riser Package
MASP	Maximum Anticipated Surface Pressure
MMS	Mineral Management Service
PFD	Probability of Failure on Demand
PT	Pressure Test
RWP	Rated Working Pressure
SEM	Subsea Electronics Module
VBR	Variable Bore Ram
WAR	Well Activity Report
API	American Petroleum Institute

1 Introduction

The blowout preventer (BOP) is a vital tool for the prevention and mitigation of loss-of-well control events. The BOP contains multiple elements that are capable of sealing the wellbore to prevent the transmission of hydrocarbons and pressure from potentially reaching the rig or entering the environment. The reliability and effectiveness of the BOP and its wellbore sealing elements have received considerable scrutiny following the failure of the system during the 2010 BP Deepwater Horizon incident [1].

As a vital barrier to the uncontrolled release of hydrocarbons from the well, there are numerous testing requirements for the BOP and its elements/components. This study examines the time interval for a particular subset of tests, the pressure tests of the pipe rams, variable bore rams (VBRs), and annulars. The current time interval between pressure tests of these components is specified in §250.737 of the Code of Federal Regulations (CFR) [2], which permits an upper limit of 14 days between pressure tests. This time interval has been in place since 1998, when it was modified from 7 to 14 days based on the findings of a study performed by Tetrahedron Inc. [3] for the then Minerals Management Service (MMS). Since that time, there have been additional studies examining potential modifications to the pressure testing interval [4-6], but no changes have been made to the time interval specified in regulation.

1.1 Project Objective and Analysis Methodology

The objective of this project is to examine the impact of an extension of the time-based BOP pressure testing interval for pipe rams, VBRs, and annulars beyond the current 14-day CFR requirement. A possible extension of the BOP pressure testing interval has the potential to affect both BOP component reliability and also rig operations. The current study sought to assess both factors, as the report outline in Figure 1-1 demonstrates. While Section 2 provides background information on applicable regulations, standards, and BOP testing, the following two sections examine the operational and component reliability effects.

Section 3 explores the potential impact on rig operations. This study begins with an assessment of the effect on rig safety, including both downhole and rig-floor operations. Following this, an economic model is developed to examine the possible industry-wide cost savings associated with an extension of the BOP pressure testing interval.

The potential impact on BOP component reliability is examined in Section 4. This study begins with a success path assessment to determine those components affected by the BOP pressure testing interval extension. This is followed by both a qualitative and quantitative reliability assessment for those identified components. Through the utilization of historical component performance data, standards assessment, discussions with industry, and component reliability modeling, key insights are derived regarding the implications for component reliability.

Based on the findings of Sections 3 and 4, a path forward is described in Section 5. This section documents the major analysis findings and also provides a series of recommendations established through an assessment of the study results.

Project Objective

Determine the impact of a potential extension of the time-based BOP pressure testing interval beyond the current 14-day requirement

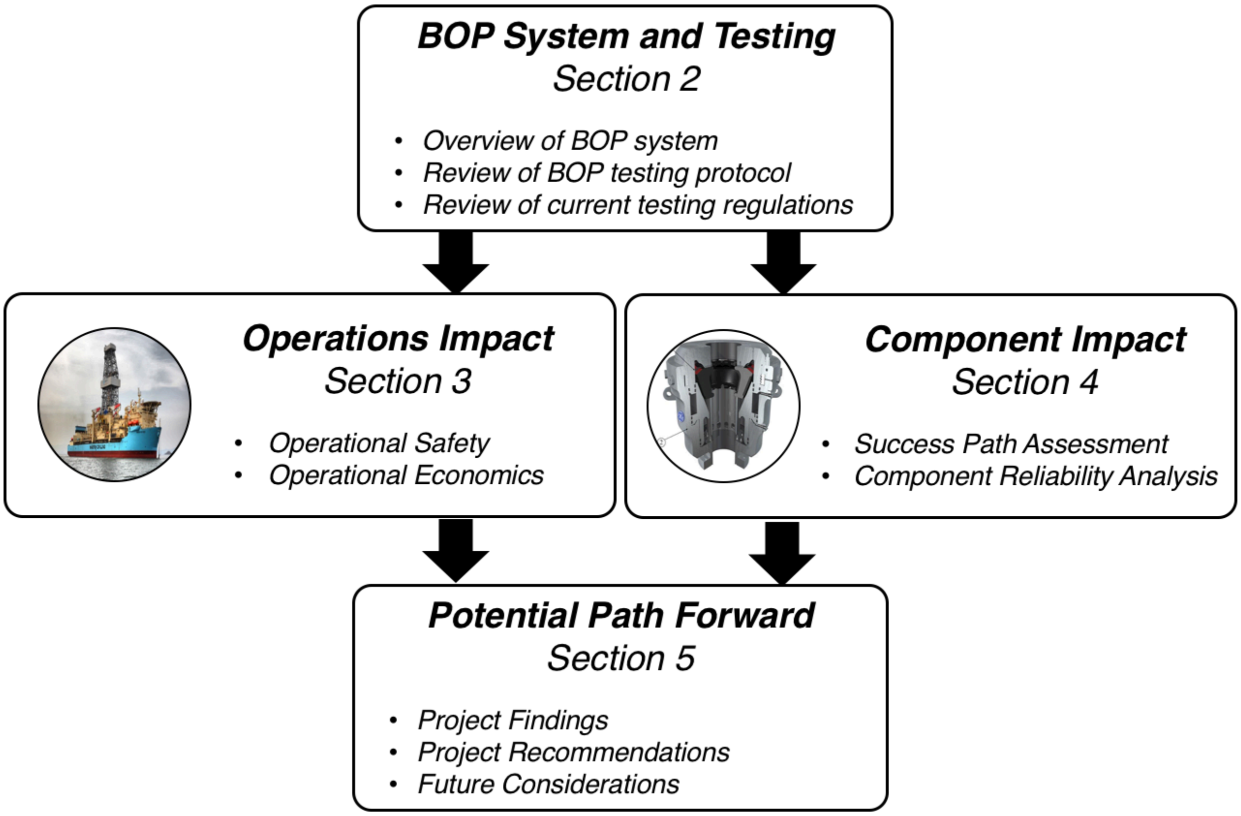


Figure 1-1: Overview of Report Structure

Throughout the report, key points and key findings are highlighted using the boxes shown in Figure 1-2. **Key points** are details or aspects of the current analysis that are particularly impactful or insightful. **Key findings** represent those analysis results that are important to the final conclusions of the current project. Section 5 provides an overview of all the key findings documented in the report.

Key Point	***Key Finding***
These boxes highlight key aspects or details regarding the current analysis	*These boxes highlight key analysis results of the current project*

Figure 1-2: Boxes Highlighting Key Points and Key Findings

2 Overview of the BOP System and Testing

This section provides an overview of the BOP systems and components, including details regarding the performance of both function and pressure tests. In addition, the differences and similarities between BOP pressure testing and well control events are reviewed.

2.1 BOP Systems and Components

The BOP is a complex electro-hydraulic system. A recent Argonne report describes the BOP systems in detail [7], and only an overview is provided here. Figure 2-1 shows the typical layout of the systems and components associated with the closure of a pipe ram, VBR, or annular for a subsea BOP. As the figure demonstrates, the majority of the components necessary to activate a pipe ram, VBR, or annular are located on the surface (rig), including the surface control system, the hydraulic power system, and the AC power system. Additional control hardware is placed on the Lower Marine Riser Package (LMRP) for subsea BOPs, with only power hydraulic fluid lines, shuttle valves, and the ram/annular on the BOP itself.

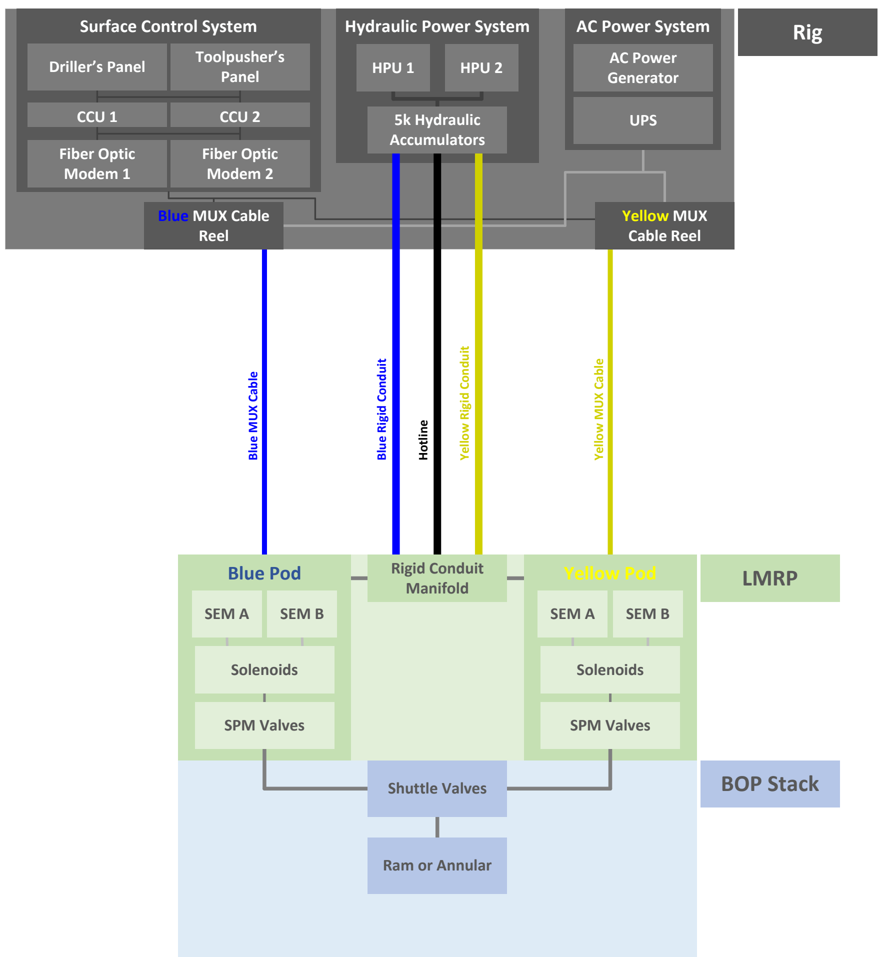
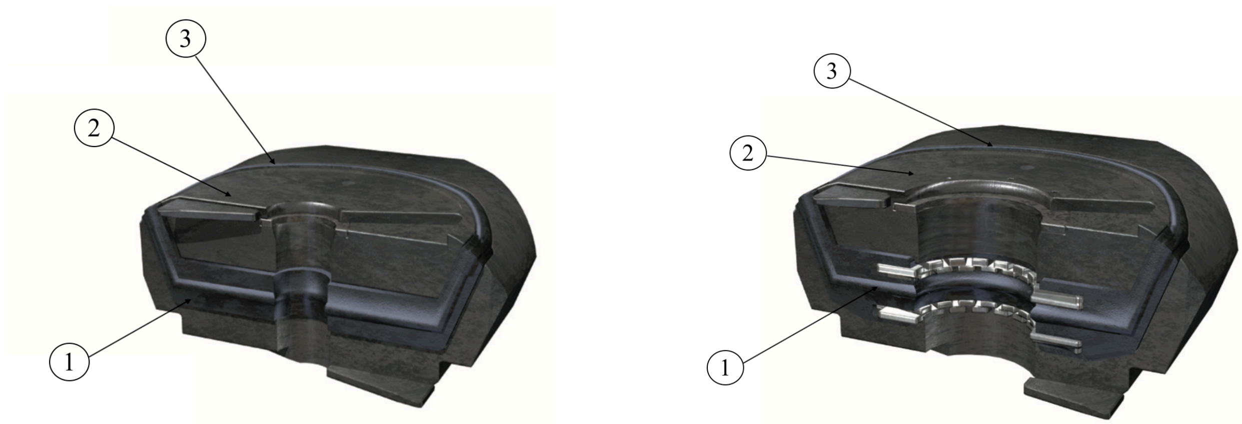


Figure 2-1: Systems and Components Associated with Ram/Annular Closure[1]

[1] Although not shown in the figure, an additional annular is typically positioned on LMRP.

> ***Key Point***
>
> *Pipe rams, VBRs, and annulars contain multiple elastomers that prevent the communication and transmission of pressure and fluids within the wellbore annulus and from the wellbore to the environment.*

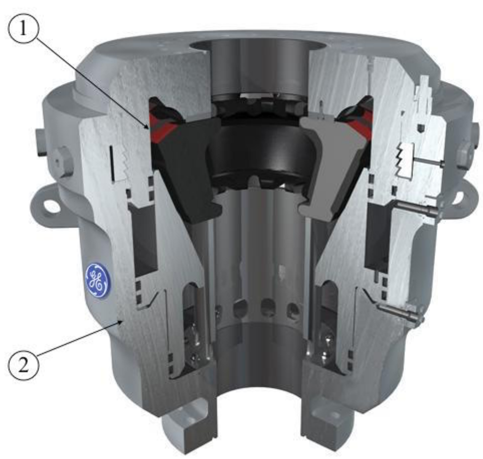
For the current study, the pipe rams, VBRs, and annulars are of particular importance. Each of these components is designed to seal the wellbore annulus that surrounds the drill string. The pipe rams and VBRs have multiple rubber (elastomer) seals to accomplish this task, as shown in Figure 2-2 for typical designs. For pipe rams and VBRs, the top seal and packer seals prevent the communication of pressure across the ram component within the wellbore annulus. The packer seals mate against the drill pipe that runs through the BOP, while the top seal mates against the top of the ram cavity. Annulars typically consist of a single rubber (elastomer) packer that also mates against the drill pipe to seal the wellbore annulus, as shown in Figure 2-3.



1 – Packer Seal
2 – Ram Body
3 – Top Seal

1 – VBR Packer Seal
2 – Ram Body
3 – Top Seal

Figure 2-2: Example Elastomer Seals on Pipe Ram and VBR [8]



1 – Packer
2 – Annular Body

Figure 2-3: Example Elastomer Seals on Annular [9]

There are many additional elastomer seals on a typical ram or annular, as shown in the example ram layout in Figure 2-4. While the packer seal and top seal are tasked with preventing wellbore pressure from entering the upper portion of the wellbore annulus, there are other elastomer seals that are designed to prevent wellbore pressure from entering the ram piston operating chamber or from entering the environment through the ram body. These include the ram shaft seals and bonnet door seals. Additional elastomer seals, such as the piston seals, provide isolation of hydraulic control fluid, but not wellbore fluid.

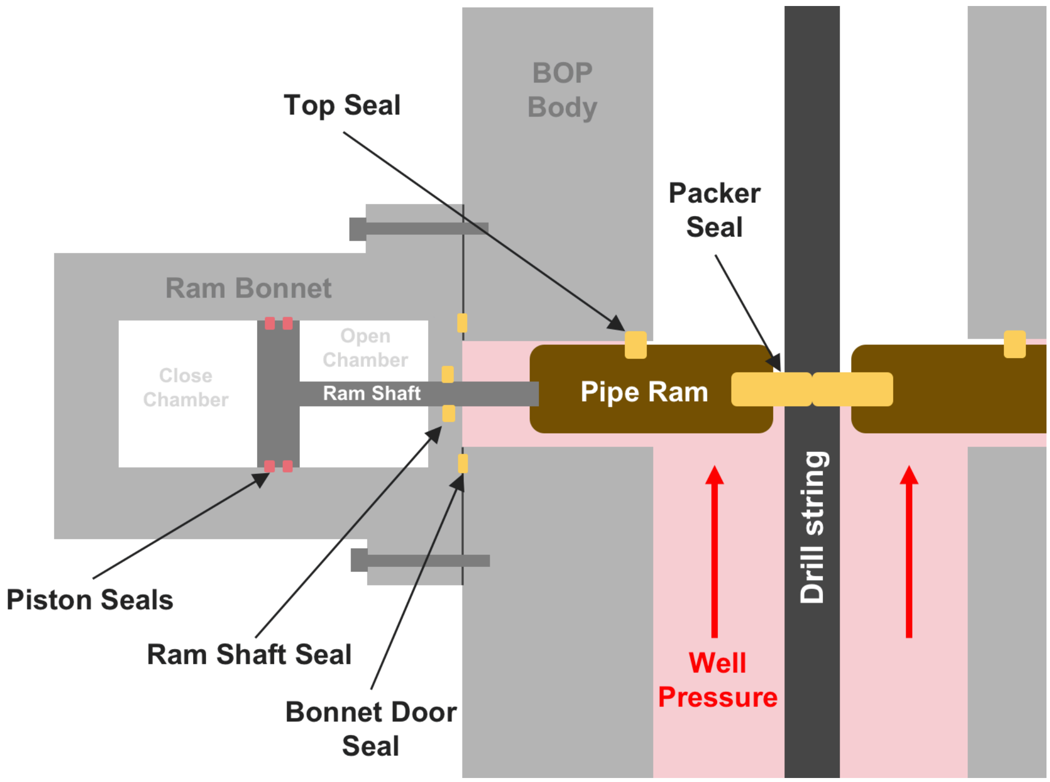


Figure 2-4: Example Elastomer Seals on Complete Ram Element

There are many different types of elastomer materials, but the most common categories are, natural rubber, nitrile butadiene rubber (NBR), hydrogenated nitrile butadiene rubber (HNBR), carboxylated nitrile butadiene rubber (XNBR) and fluoroelastomers (FKM). The selection of the particular elastomer to be used in the BOP elements usually depends on the predicted wellbore conditions (temperatures, pressures, fluids, etc.) and planned wellbore operations, as will be discussed in Section 4.2.2.

2.2 BOP Testing

The BOP system is subjected to intermittent proof tests, which verify that the components and systems are operating according to their design requirements. All BOP elements, including the shear rams, pipe rams, VBRs, and annulars, are both function tested and pressure tested. This section begins with an overview of the current BOP testing requirements, as outlined in the U.S. CFR and API standards. This is followed by a description of the tests, including pressure test monitoring, and a comparison between BOP testing and actual well control events.

2.2.1 Current U.S. Regulation and API 53

As mentioned in Section 1, most of the requirements for BOP testing are outlined in §250.737 of the CFR [2]. The section is separated into four main paragraphs that detail the pressure testing frequency, the pressure testing procedures, the duration of pressure tests, and additional testing requirements. Within the "Additional Test Requirements" portion of §250.737, it is stated that the testing requirements of API Standard 53 4th Edition [10] must be followed. However, included is the additional caveat that if there is a conflict between §250.737 and API 53, then §250.737 supersedes API 53.

Key Point

API 53 and §250.737 have several key differences regarding BOP testing frequency and protocol.

While there are several key differences between §250.737 and API 53 regarding BOP function tests and pressure tests for BSRs[2], the conflict that is typically cited as having the largest impact on industry relates to the pressure testing requirements of pipe rams, VBRs, and annulars. As shown in Table 2-1, CFR requires pressure testing of these components every 14 days while the BOP is installed on the well. In comparison, API 53 requires pressure tests every 21 days. In addition, many U.S. land-based [11] and international regulators [12] use the 21-day interval specified by API 53.

Table 2-1: Comparison of CFR and API BOP Pressure Testing Requirements

Topic	*CFR 250.737*	*API 53*
Pressure Testing *Rams (non-shear) and Annulars*	***(a2) (d6):*** *Requires pressure tests every 14 days*	***6.5.3.4.1 (surface) 7.6.5.4.1 (subsea):*** *Requires pressure tests every 21 days*

In theory, the more stringent BOP testing protocol outlined in CFR is believed to improve BOP reliability. However, there are additional, important repercussions of this requirement. The difference in pressure testing protocol for pipe rams, VBRs, and annulars results in more frequent pressure testing of these components. This increases the number of pressure cycles the equipment, including the rams/annulars and other BOP components, is subjected to. In addition, the pressure tests require a significant amount of time to perform, which increases rig downtime (more detail on this factor in Section 2.2.2). These factors are part of the reason why this pressure testing protocol difference is considered to have the largest impact on industry operations out of all the conflicts between CFR and API 53.

[2] For function test differences, see CFR §250.737 (d9)(d5iA)(d5iC) and API 53 6.5.3.1 (surface) 7.6.5.1.3 (subsea). For BSR pressure testing differences, see CFR §250.737 (a2)(b2) and API 53 7.6.5.4.2 and Table 10.

2.2.2 Function Test and Pressure Test

Both function tests and pressure tests of the pipe ram, VBR, and annular BOP elements are performed. The function tests and pressure tests are very similar, as both tests involve closing and opening the BOP element utilizing the surface (rig) control system and surface hydraulic pressure, as described in Table 2-2. The key difference between the function and pressure test is the pressure condition within the wellbore once the BOP element is closed. In the function test, the wellbore sealing element is closed, but is then re-opened without being subject to a wellbore pressure differential across the sealing element. In the pressure test, a pressure differential (with magnitude determined by ref [2]) is applied across the BOP sealing element to test the wellbore annulus sealing capability. Section 4.1 will provide more information on the purpose of the two tests and how they impact system reliability.

Table 2-2: BOP Non-shear Ram and Annular Tests

Test	***Description***	***Purpose***
Function Test	*A surface (rig) command closes then opens the ram/annular element utilizing surface (rig) hydraulic power.*	*Proof test of the BOP control system and the ability of the ram/annular to close/open.*
Pressure Test	*A surface (rig) command closes the ram/annular element utilizing surface (rig) hydraulic power. Once closed, a wellbore pressure differential is applied across the ram/annular. The ram/annular is then opened from a surface (rig) command.*	*Proof test of the BOP control system, the ability of the ram/annular to close/open, and ram/annular ability to isolate wellbore pressure.*

Pressure testing of the BOP rams and annulars is a method to gauge the adequacy of the component to contain wellbore (specifically wellbore annulus) pressure during well control events. In general, pressure testing of BOP rams/annulars contains two separate tests: a low-pressure and a high-pressure test. Since some ram designs may seal better against high-pressure conditions due to wellbore assist, it is important for the low-pressure test to be performed first. Low-pressure tests are performed between 250 and 350[3] psi. The pressure differential must be held for five minutes for subsea BOP rams/annulars, while three minutes is permissible for surface BOPs under certain conditions [2].

For high-pressure tests, the requirements differ for pipe rams and VBRs versus annulars. For pipe rams/VBRs, the pressure must equal the RWP or MASP plus 500 psi. For annulars, the pressure must equal 70% of the RWP or be 500 psi greater than MASP, whichever is lesser. As with the low-pressure test, the differential pressure must be held for five minutes for subsea BOPs.

To prepare for a BOP pressure test, a series of actions must be taken, which differ slightly depending on how the test is to be conducted. First, the drilling bit is pulled off the bottom of the hole into the nearest cased section. This is primarily done to prevent the potential of hole collapse onto the drill string during testing. A pressure test may be performed utilizing either a test plug, placed downhole of the BOP using the drill string, or a test ram positioned at the bottom of the BOP[4]. If a test plug is used, additional movement of the drill string is necessary to place the test

[3] If the pressure exceeds 350 psi, it must be bled back before starting the pressure test. However, if pressure exceeds 500 psi, the test must be stopped and reinitiated from zero (differential) pressure.

[4] A test ram is typically a VBR placed upside down at the bottom of the BOP, which allows it to hold pressure from above.

plug downhole. For a deepwater well, the process of running the test plug downhole can add several hours to the test preparation procedure and is a major motivation for the use of a test ram on the BOP instead.

Once the test plug is in place or the test ram is closed, the ram or annular to be tested is closed, and the wellbore volume within the BOP is pressurized using the choke or kill lines and pressure from the cement pumps on the rig. For each BOP element to be pressure tested, there is a series of choke/kill line valve manipulations that are necessary to create pressure within the proper area of the BOP. Figure 2-5 depicts an example pressurization pathway for a pressure test of an upper pipe ram, utilizing a test ram at the bottom of the BOP. As noted in the diagram, pressure is typically measured using a pressure transducer located on the rig near the cement unit.

In addition to the pipe rams, VBRs, and annulars, there are other components that are pressure tested during the 14-day test, shown in Table 2-3. This includes the choke and kill line valves and surface-installed drill-string safety valves, such as the inline BOPs (IBOPs) and fully operating safety valves (FOSVs).

Table 2-3: Other Components Tested During 14-Day Pressure Test

Component	*Description*
Choke/Kill Valves	*Includes the line valves, BOP inlet valves, and surface manifolds valves*
IBOPs and FOSVs	*Inline BOPs (IBOPs) and Fully Operating Safety Valves (FOSVs) are two types of surface-installed drill-string safety valves.*

[1] Contingency valves deployed from the rig to prevent uncontrolled flow through the drill string.

A subsea BOP pressure test can consume a significant amount of rig time to perform due to the number of tests that must be completed and the time period necessary for system pressure to stabilize for each test. A typical deepwater BOP stack can require more than 10 separate tests during a pressure test cycle. As the test fluids are pumped from the rig to the subsea BOP, the fluids will cool due to the ambient temperature difference and induce a pressure change in the closed system. Therefore, some tests require a significant waiting period (in addition to the pressure holding period specified in CFR/API 53) to allow for thermal changes and pressure stabilization.

The exact amount of time necessary to perform a pressure test can vary greatly depending on BOP setup, water depth, fluid properties, and the pressure test protocol utilized (discussed in Section 2.2.3). Past studies have found that a typical subsea pressure test averages around 13 hours of rig time [6, 13]. In comparison, a BOP function test may take less than one hour to perform.

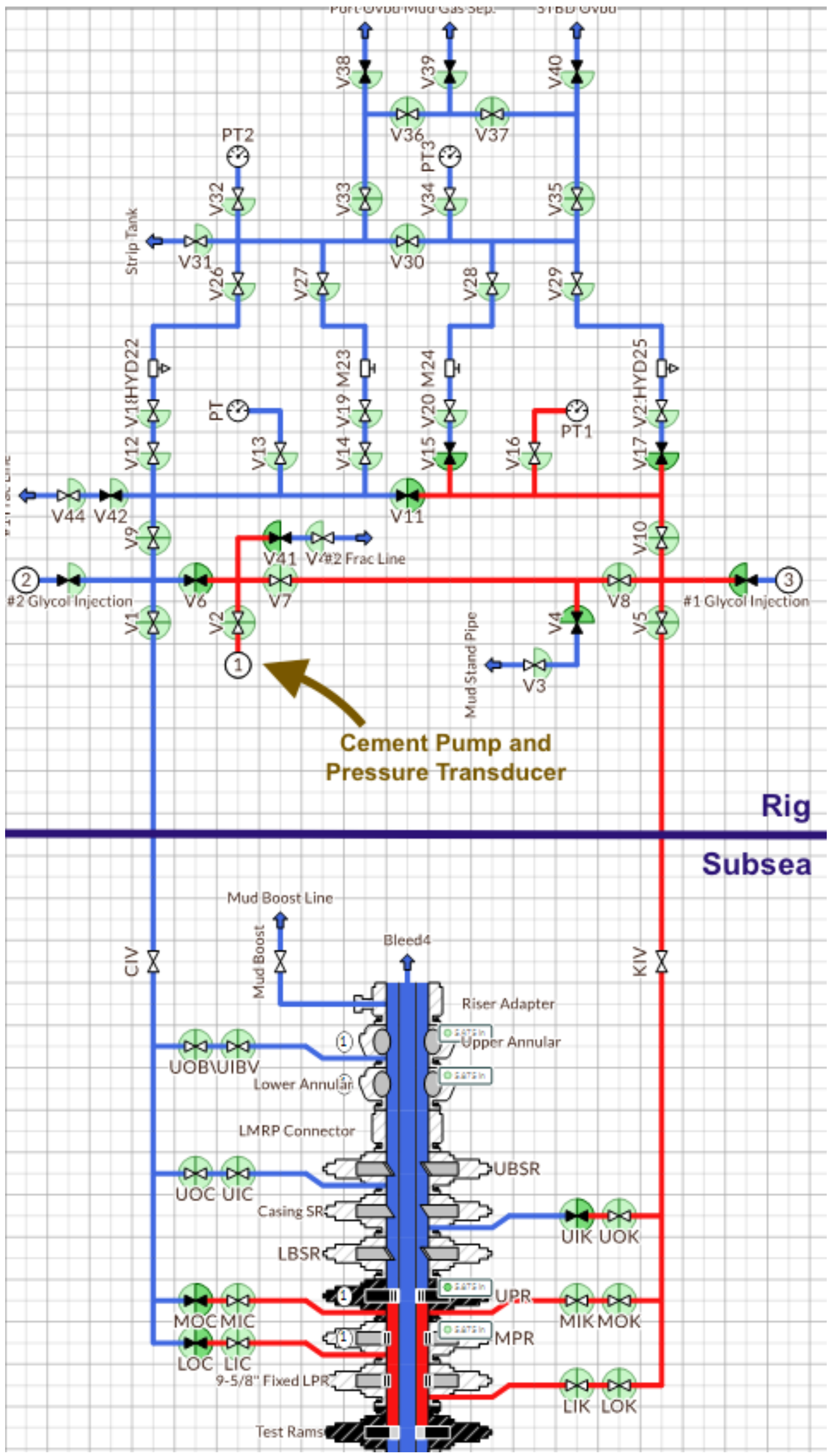


Figure 2-5: Pressure Test Schematic[5]

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5 Schematic showing a subsea BOP utilizing a test ram. Schematic created using IPT Global SurePlan® [14].

> ***Key Point***
>
> *In general, there are three main reasons to pressure test the BOP:*
>
> *1) Stump/Installation/re-latch*
> *2) Scheduled by time*
> *3) After certain subsea operations*

There are several reasons why a BOP pressure test is performed, as outlined in Table 2-4, which contains both regulatory requirements and general "good practices." First, before a subsea BOP is run to the wellhead, a stump test is performed on the rig to verify the performance of the BOP components prior to the start of operations and to verify any maintenance was performed correctly. This is regulatory requirement under §250.737 (d)(3), and the purpose of the test is to avoid running a BOP subsea with nonoperational/failed components. Second, a pressure test is performed once the BOP is installed on the wellhead. This test is a regulatory requirement under §250.737 (d)(4) and verifies the performance of the BOP before subsequent well operations begin. Similarly, regulation requires a BOP pressure test after the repair of any well-pressure containment seal on the BOP (§250.737 (d)(8)), or upon the re-latch of the BOP to the wellhead (§250.734 (b)(2)). Next, a pressure test may need to be performed after the running of casing or a liner[6]. There are additional pressure tests due to the passage of time, which are the majority of subsea pressure tests. These tests fulfill the regulatory requirement in §250.737 (a)(2) to pressure test the BOP before 14 days have elapsed. Although not listed in the table, §250.737 (a)(4) also includes a provision where the BSEE District Manager has the authority to require additional pressure tests, if warranted.

Table 2-4: Reasons for BOP Pressure Test

Pressure Test	***Requirement***	***Description***
Stump	*§250.737 (d)(3)*	*Performed on the stump on the rig prior to running the BOP subsea.*
Installation	*§250.737 (d)(4)*	*Performed when the BOP is first installed on the wellhead.*
After BOP re-latch or repair[1]	*§250.737 (d)(8), §250.734 (b)(2)*	*Performed after repair or after BOP removal from wellhead (overlap with previous requirements).*
After Running Casing or Liner	*§250.737 (a)(3)*	*Performed after running casing/liner (with exceptions[2]).*
Scheduled by Time	*§250.737 (a)(2)*	*Performed before 14 days have elapsed since last subsea pressure test.*
After Certain Events	*§250.738 (i), API 53, best practice*	*Typically rare events, such as after a pipe shearing event or well-control event (additional detail on possible operations that would induce a pressure test is provided in Section 4.2.2)*

[1] Following the repair of any well-pressure containment seal.

[2] This pressure test may be omitted if "if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 14 days.

Lastly, a pressure test may also be performed after certain operations, if it is thought that the operation may have damaged or degraded certain BOP components. There is little direct regulation regarding these tests, although regulation does cite API 53, which includes several provisions for when an additional pressure test may be needed. For example, API 53 5.2.13

[6] There are additional caveats to this requirement, as stated in §250.737 (a)(3), "You may omit this pressure test requirement if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 14 days (or 30 days for blind shear rams)…"

discusses the potential for additional testing following the uncontrolled flow of fluids containing sour gas, and 7.6.11.7.7 mentions additional pressure testing following well control events where pipe was sheared[7]. API 53 7.6.5.4.1 also notes that additional pressure tests may be needed according to the equipment owner or site-specific requirements. Section 4.2.2 of the current report provides additional information on wellbore conditions or operations that may warrant a pressure test. In general, the performance of a pressure test after certain operations is rare, as the occurrence of events that may degrade or damage the elastomers is purposefully avoided.

It is important to note that a pressure test may serve to meet multiple requirements. For example, a pressure test may be conducted after a kick has been circulated out of the well. This may verify that a component was not damaged during the kick (for instance, if there was stripping of annular during the kick circulation process) while also serving as the 14-day test if nearing the end of the time interval.

As stated above, the most frequent pressure test is the time-based pressure test to fulfill the 14-day requirement. Although current regulation stipulates a maximum time interval of 14 days between pressure tests, in reality, the time period between tests is usually shorter. This is typically due to the sequence of well operations. An operator will often schedule the pressure test when the well is both in a safe and stable condition and it is convenient for well operations. Past studies have found that the time interval between pressure tests is closer to 11 days [6]. This is consistent with data collected as part of the current project.

2.2.3 Pressure Test Monitoring

During a pressure test, there are multiple ways to monitor and record wellbore pressure to assess the performance of the BOP component. Typically, pressure transducers at the cement unit are used to measure pressure within the system[8]. This pressure reading is used to determine the absolute pressure at the BOP by accounting for the hydrostatic pressure of the fluid in the system and the surface pressure. In terms of monitoring test fluid pressure, current regulation (§250.746 (a)) allows two options: pressure charts (circular chart recorders) and digital recorders.

Historically, circular chart recorders (CCRs) have been used to monitor system pressure. These electromechanical devices record pressure readings onto rotating graph paper. Although CCRs have been successfully used by industry for decades, the resolution of the chart recorder is limited due to the nature of the device. In recent years, many operators have switched to digital recorders.

[7] §250.738 (i) also directly requires a BOP pressure test after any activation of a shear ram and pipe or casing is sheared.

[8] The inclusion of pressure transducers within subsea BOPs (or choke/kill lines) is becoming increasingly popular for operational purposes, but these sensors are not utilized for pressure testing.

> ***Key Point***
> *Digital pressure testing utilizes the same pressure-measuring equipment as CCR pressure testing, but provides several benefits regarding the analysis and assurance of pressure test performance.*

While both digital recorders and CCRs utilize the same pressure sensors, digital recording can provide several additional benefits. First, digital recording offers greater resolution of the pressure testing results and aids in the archiving of the information, which can then be used for subsequent analysis. Both operators and specialized companies are now beginning to utilize digital pressure testing data to assess component performance over multiple pressure tests. This process allows the possibility to shorten the length of time a component pressure test requires through the comparison of current test performance to past, successful pressure tests. If it can be shown, with adequate confidence, that the component is responding in a similar fashion to past pressure tests, a test may be able to be terminated early. For example, IPT Global has received permission from BSEE to perform such calculations based on proprietary algorithms following a multi-year pilot program. Also, through the analysis of pressure test performance data, it may be possible to identify signs of component degradation before the BOP component fails. For example, if the leak-off rate of the component during the test (*i.e.*, the change in pressure within the sealed volume over time) is significantly different than past pressure tests under similar conditions, it may be indicative of wear or damage to the BOP sealing element or other problem in the pressure testing configuration.

In addition to the digital archiving and analysis of pressure testing data, certain operators have seen added value in onshore real-time oversight of BOP tests to ensure compliance and efficiency, which is not possible when utilizing CCRs alone. Lastly, digital pressure testing is typically used in conjunction with test planning and workflow software, which integrates the testing procedures and results, improving confidence in the testing process and providing greater clarity when reviewing past test performance. This factor can also help mitigate some of the operational risks associated with BOP pressure testing, as will be discussed in Section 3.1.3.

2.2.4 Pressure Test vs. Well Control Event

Although pressure tests are performed to assess the performance of the ram/annular to isolate pressure during well control events, there are differences between testing conditions and real-world events. Of particular importance for the current study is the equipment utilized during the event. As shown in Figure 2-6, during a well control event, a ram or annular will be closed to prevent the communication of annulus pressure across the BOP. The annulus pressure is isolated to the internal body of the BOP through the use of the ram/annular and the associated isolation valves on the choke and kill lines. Once stabilized, the wellbore fluids are then circulated utilizing the choke/kill lines.

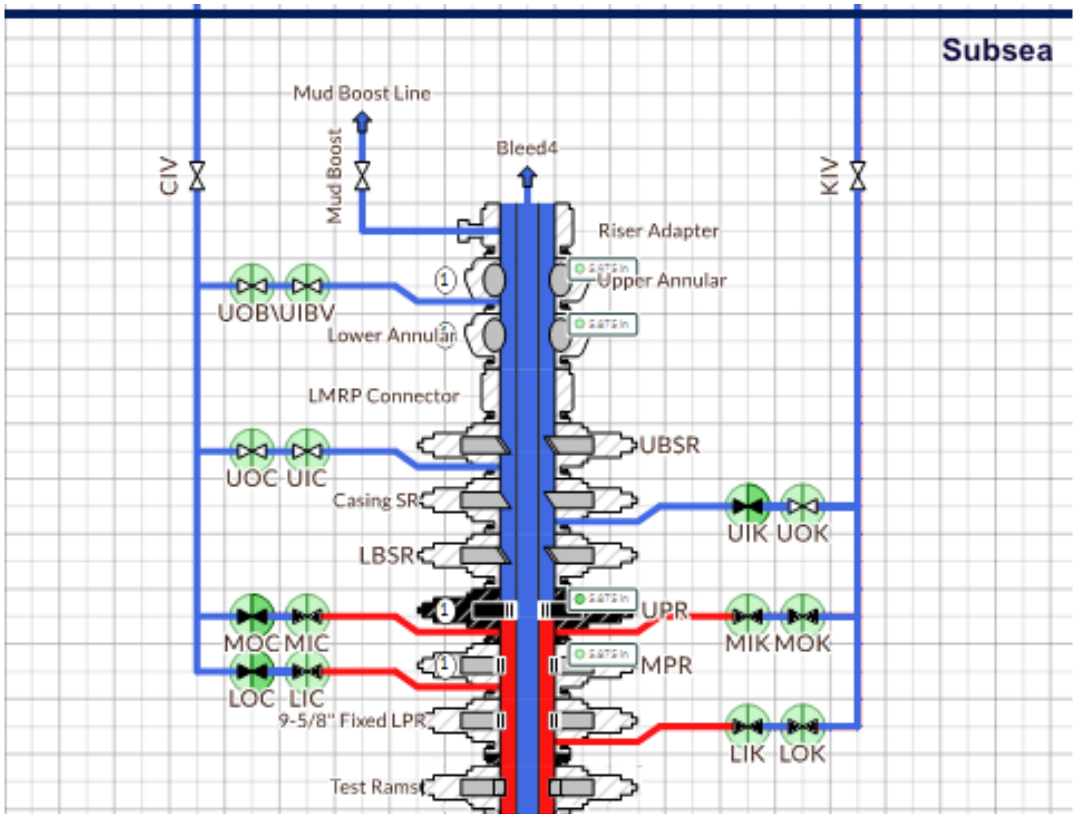

Figure 2-6: Well Control Action Pressure Schematic[9]

> ***Key Point***
>
> *A BOP pressure test involves many components that would not experience a pressure increase during an actual loss-of-well control event.*

The well control event schematic is quite different from that shown for a pressure test in Figure 2-5. In a pressure test, hydraulic pressure is created at the surface (rig). The hydraulic fluid and pressure are communicated to the BOP through a choke or kill line, and the BOP body annulus is isolated from the downhole wellbore through the use of a test ram or test plug. Multiple systems, each including its own piping and valving, are necessary for the successful completion of a pressure test. However, each one of these components presents another failure pathway for the pressure test, as a leak would result in a reduction of pressure and the need for a retest. The BOP ram or annular becomes only one of many components subjected to the test. Table 2-5 compares those components utilized during a BOP pressure test versus those used during a well control event.

During BOP pressure tests, many initial test failures can be attributed to issues with components other the BOP sealing element, such as misaligned valves or leaks in supporting equipment. Failures necessitate the need for repeated pressure tests as these problems, which are *not* related to the BOP ram/annular, are identified and addressed. Valuable rig-time is spent attending to issues associated with test equipment or non-critical, auxiliary equipment not utilized during well control operations.

---

[9] Schematic created using IPT Global SurePlan® [14].

Table 2-5: Components Utilized During BOP Pressure Testing and Well Control Events

Component	*Pressure Test*	*Well Control Event*
Ram/Annular	✓	✓
Choke/Kill Lines	✓	O
Test Plug/Test Ram	✓	✗
Choke/Kill BOP Inlet Valves	✓	✓
Choke/Kill Surface Manifold Vales	✓	O
Cement Pumps and Piping	✓	✗

✓ - Used
O - Used for well fluid circulation
✗ - Not Used

3 Operational Impact

The potential extension of the time-based BOP pressure testing interval has repercussions on both operational safety and operational economics. This section reviews both of these factors to determine the overall impact on offshore operations.

3.1 Operational Safety

BOP pressure tests require a significant amount of downhole and on-rig operations. Each operation has risks associated with it. The following subsections explore three areas where operational safety may be impacted by a reduction in the frequency of BOP pressure testing.

3.1.1 Reduction in Downhole Operations

As described in Section 2.2.2, the BOP pressure testing procedure typically begins by halting drilling operations and pulling the drill string off of the bottom of the hole. If a test ram is being used on a subsea BOP, then the bottom hole assembly (BHA) is pulled up into the last cased section of the hole. This is done to avoid the potential for the drill string to get stuck if hole collapse were to occur onto the BHA. If a test plug is being used for the BOP pressure test, then the drill string is tripped completely out of the well so the test plug can be inserted and tripped into the well.

Whether using a test ram or test plug, downhole operations are necessary to pull the BHA off bottom and into the proper location. Any movement of the BHA off of the bottom of the hole has the potential to induce swabbing or surging. If these effects are of sufficient magnitude, they could induce a kick and result in the need for well control operations. To compound these issues, the high frequency of the 14-day BOP pressure test often results in the need to pressure test while drilling operations are in less-than-ideal locations or stages. To ensure that the well is in a safe and stable state, the BOP pressure test may have to be performed prior to the end of the 14-day window. This is one of the reasons why the average BOP pressure testing interval is closer to 11 days, as mentioned in Section 2.2.2.

Although the occurrence of kicks and well controls issues while preparing for BOP pressure tests is generally rare, due to proper adherence of operating procedures by rig crews, the time-based BOP pressure test interval does have a direct impact on the frequency of such events. A reduction in the number of BOP pressure tests would result in fewer trips off bottom over the lifetime of the well and would also increase the likelihood that the operators will have the well in a safe and stable state before beginning the testing procedures.

3.1.2 Reduction in Rig Exposure to High-Pressure Operations

Once the drill string and BOP have been properly configured for the BOP pressure test, the BOP is then pressurized through the choke/kill lines using fluid from the rig and power from the cement pumps. The exact pressure of the "high-pressure" BOP tests depends on the specifications of the well[10], but can exceed 10,000 psi. Therefore, the cement pumps and the associated

[10] See Section 2.2.2 for specific values.

choke/kill line piping on the rig will see similar fluid pressures. The failure of the choke/kill line piping, which is typically several inches in diameter, at high pressure could pose a threat to rig personnel or equipment.

Accidents involving the rupture of choke/kill lines at the rig during high-pressure BOP testing are rare, thanks to equipment qualification standards [15] and proper procedures. However, failures have occurred in the past, such as a burst jumper line in a rig moonpool during a BOP pressure test after running casing [6]. A reduction in the frequency of BOP pressure tests also results in a reduction of these high-pressure operations on the rig and a decrease in another operational safety risk factor.

3.1.3 Reduction in System Reconfigurations

Pressure testing of BOP components requires many changes to valving alignment both on the rig and on the choke/kill lines. As shown in Figure 2-5, the choke/kill BOP inlet valves and the surface manifold valves are reconfigured to allow the transmission of fluid pressure from the cement pumps to the desired area of the BOP. The choke/kill valve arrangement is then modified as each BOP component is tested. The valve manipulations are typically performed remotely, although manual valve operators are still in service on some rigs.

Rig operators typically follow strict procedures to ensure that valving configurations are correct before returning to downhole operations, but there is a potential for valves to be left in an incorrect state. These errors are usually detected during routine operations following the test. However, since pressure testing utilizes the choke/kill lines and isolation valves that are used to circulate kicks (amongst other actions), an incorrect valve alignment could have serious repercussions if a well control event were to occur soon after test completion. A valve misalignment could result in the failure to isolate a kick or the erroneous circulation of fluid to an incorrect location during well control operations. A reduction in the frequency of BOP pressure tests results in a reduction of the number of reconfigurations of the choke/kill systems and the associated risk factors.

Key Finding

An extension of the time-base BOP pressure test interval could result in a decrease of several risk factors for both rig personnel and operational safety, including:

- *Reduction in the number of instances a drill string must be pulled off bottom*
- *Reduced exposure of rig and crew to high pressure operations*
- *Reduced potential for choke/kill system misalignment*

3.2 Operational Economics

An extension of the time-based BOP pressure test interval could have economic benefits in terms of cost savings from reduced rig downtime and increased productivity. To determine the economic impact of extending the time-based BOP pressure testing interval, a cost-savings analysis was performed. The details of the economic model are described in Appendix A, and an overview is provided here.

3.2.1 Economic Model

The economic model examines the total cost of drilling operations in the GoM over the next 10 years. The output is the cumulative annual rig lease cost across all rigs. An overview of the economic model is provided below. Additional details on the model are included in Appendix A.

3.2.2 Model Parameters

There are several input parameters to the economic model, shown in Table 3-1. The parameters relate to drilling operations in the GoM, such as the number of rigs in operation and daily lease costs. There is significant uncertainty related to each of the input parameters, as they are heavily dependent on the price of crude oil/nautral gas and other macroeconomic factors that are difficult to gauge over a 10-year timespan. In addition, there may be feedback effects not completely captured by the model. Also, many of the input parameters are correlated, such as the number of rigs in operation and the daily lease cost per rig.

Table 3-1: Economic Model Input Parameters

Model Parameter	***Description***
Time-Based BOP Pressure Testing Interval	*Time interval (days) between the time-based BOP pressure test that is required while the BOP is on the well.*
Rig Downtime per Testing Cycle	*Total rig downtime (hours) for each pressure testing cycle. This includes the time necessary to prepare and perform the pressure test.*
Daily Lease Cost per Rig	*The total daily lease cost ($) per rig. This includes direct rig costs and also associated contractors and vessels.*
Number of Rigs in Operation	*The total number of rigs in operation in the GoM in a given year.*
Rig Utilization Time	*Percentage of time in a year that a rig is operating with a BOP on the well and therefore subject to the time-based BOP pressure test requirement.*

Each of the input parameters was assigned an uncertainty distribution, shown in Figure 3-1, based on available data. These input parameter distributions assume no significant deviation of GoM drilling operations from current projections, such as changes that could occur following a major offshore incident or a sudden increase in hydrocarbon prices due to an international event. Such events have occurred in the past and may cause substantial changes to the model assumptions. The remainder of this subsections describes each model input parameter in greater detail.

The first input parameter is the interval of the time-based BOP pressure test while the BOP is on the well. For the current analysis, the time interval is the main independent variable and was varied from 10 days to 30 days. Values below the current regulatory requirement of 14 days were chosen since pressure tests are typically performed in advance of the 14-day deadline (as described in Section 2.2.2, the industry average is approximately 11.5 days).

The next input parameter is the rig downtime per BOP pressure testing cycle. This is the total rig downtime associated with each BOP pressure test and includes the time necessary to prepare for and perform the test. For example, although a BOP pressure test may take a rig eight hours to complete, there may be an additional 16 hours spent getting the well to a safe and stable state then tripping in and out of the hole to run the test plug. Therefore, the total rig downtime for that example scenario is 24 hours. If failures occur during testing, whether from actual component failures or system alignment issues, this adds to the total rig downtime. This parameter was estimated based on conversations with industry and an analysis of operational logs. This is an industry-averaged value and includes both surface and subsea BOP rigs. A normal distribution was chosen to represent this parameter, with a mean of 24 hours and a standard deviation of 2. It is important to note that this factor does not account for the potential of rig downtime associated with unplanned BOP pulls for repairs, which could reduce the calculated benefit, as it could result in additional downtime regardless of the pressure testing interval.

The daily lease cost per rig is another input parameter and represents the total daily operating cost of drilling. This value includes the direct costs of the rig lease and also the additional costs of the associated contractors and supply vessels. This is an industry-averaged value and includes both surface and subsea BOP rigs. This parameter was estimated based on data from operators and contractors. A normal distribution was chosen to represent this parameter, with a mean of $1,000,000 per day and a standard deviation of $125,000.

The number of rigs in operation gives the total numbers of rigs engaged in drilling activities in the GoM in a given year. This is an industry-wide value and includes both surface and subsea BOP rigs. The parameter values are based on projections from the U.S. Energy Information Administration (EIA) and discussions with industry. However, this factor can vary greatly depending on the price of crude oil/natural gas, and there is significant uncertainty when projecting over the next 10 years. A normal distribution was chosen to represent this parameter, with a mean of 59 rigs and a standard deviation of 4.

The final rig-related input parameter is the total rig utilization time. This is the percentage of time, in a given year, that the rig has a BOP on the well and is therefore subject to the time-based BOP pressure test. This parameter was estimated using operational logs and conversations with industry. For individual rigs, this value can vary greatly depending on the conditions of the specific well. However, the parameter represents an industry-averaged value and includes both surface and subsea BOP rigs. A normal distribution was chosen to represent this parameter, with a mean of 59 percent and a standard deviation of 3.

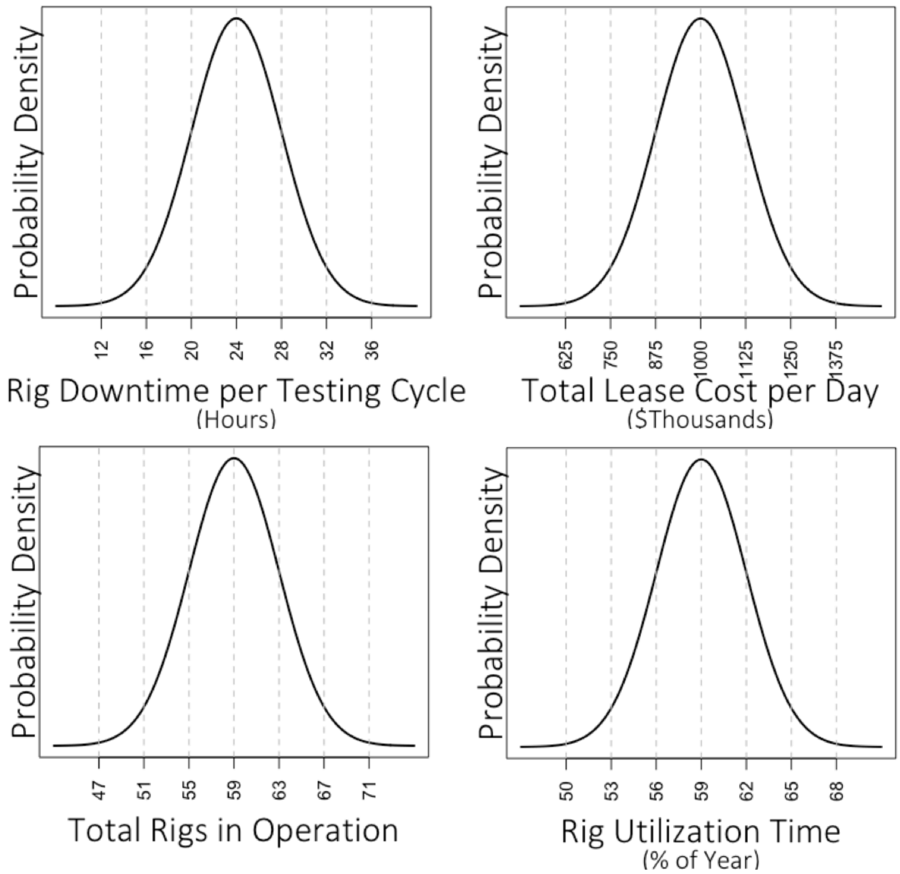

Figure 3-1: Economic Model Input Parameter Uncertainty Distributions

There are other potential economic factors that are not included or explicitly modeled in the following economic analysis. For example, an extension of the time-based pressure testing interval could result in a reduction of drilling costs that are sufficiently large to spur additional GoM activity not currently in projections. Similarly, the reduction in the time-based pressure test interval could also make drilling activity more efficient (beyond just the rig downtime benefit), resulting in shorter wells. Also, as described in Section 3.1, an extension of the time-based BOP pressure testing interval could reduce several risk factors related to rig operations, such as the possibility of inducing kicks and choke/kill valve misalignment. These events not only require additional rig downtime to resolve but have the potential to result in an accident scenario, which could have large economic effects. Although the likelihood of such an event is small, a single accident from these causes could dramatically impact the calculated cost savings.

3.2.3 Cost Savings Associated with Extending the BOP Pressure Testing Interval

To assess the potential nominal cost savings associated with an extension of the time-based BOP pressure testing interval, the economic model was utilized to explore the uncertainty space of the input parameters. A bounding analysis was performed rather than direct Monte Carlo simulations due to limitations of the economic model. A total of seven analyses were performed utilizing the bounding values in Figure 3-2. In addition to mean values for the input parameters, analyses were conducted using plus/minus one, two, and three sigma values.

Table 3-2: Economic Model – Input Values

Parameter	Input Values						
	-3σ	-2σ	-1σ	Mean	+1σ	+2σ	+3σ
Rig Downtime per Testing Cycle	18hr	20hr	22hr	24hr	26hr	28hr	30hr
Daily Lease Cost per Rig	$625k	$750k	$875k	$1,000k	$1,125k	$1,250k	$1,375k
Number of Rigs in Operation	47	51	55	59	63	67	71
Rig Utilization Time	50%	53%	56%	59%	62%	65%	68%

The results of the model can be seen in Figure 3-2 and Table 3-3, which show the industry-wide cost savings per year, averaged over the next 10 years. All cost estimates were compared to an 11-day time-based BOP pressure testing interval, which is the approximate average length of time between time-based BOP pressure tests currently on the GoM (see Section 2.2.2). U tilizing this information, it was assumed that if the time-based pressure testing interval were to be extended to 21 days, this would result in an average time between time-based BOP pressure tests of approximately 18 days. If a 28-day interval requirement were utilized, this was assumed to result in an average time between time-based BOP pressure tests of approximately 25 days.

Utilizing mean values of the input parameters, an extension of the time-based BOP pressure testing interval to 21 days would result in an industry-wide cost savings of $413 million per year over the next 10 years. If a 28-day time-based pressure testing interval was utilized, this would result in an industry-wide cost savings of $596 million, assuming mean input parameter values.

Table 3-3: Economic Model – Key Results[11]

Time-Based BOP Pressure Testing Interval	Industry-Wide Cost Savings per Year ($Millions)[1]						
	Lo3	Lo2	Lo1	Mean	Hi1	Hi2	Hi3
21-Day[2]	$133.3	$207.2	$297.3	$413.0	$563.0	$733.1	$937.6
28-Day[3]	$193.2	$296.4	$430.4	$595.9	$817.5	$1065.3	$1378.5

[1] Nominal value, averaged over next 10 years.
[2] Comparison of 18-day versus 11-day.
[3] Comparison of 25-day versus 11-day.

Key Finding

An extension of the time-based BOP pressure testing interval could result in the following industry-wide cost savings:

***21-Day**: $400 Million/year*
***28-Day**: $600 Million/year*

[11] Note that the Lo and Hi values do not represent corresponding standard deviation values, but are bounding values, as all input parameters were modified jointly and the impact of correlation was not quantitatively addressed.

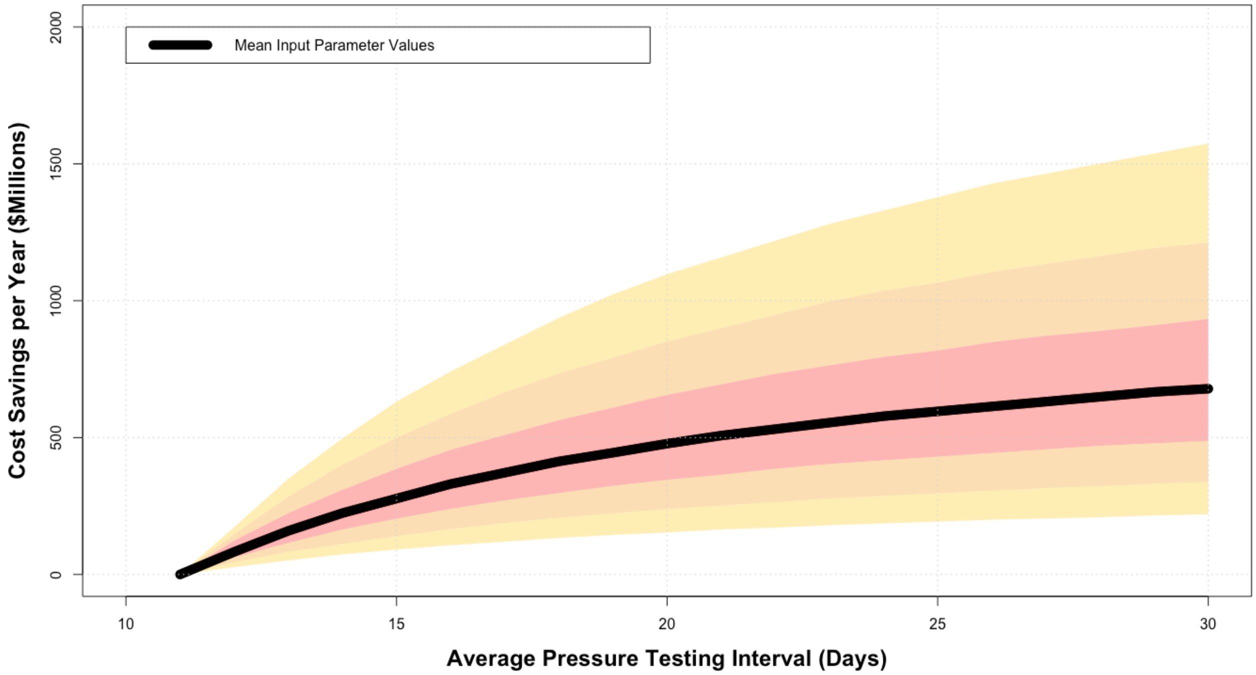

Figure 3-2: Economic Model Results

4 Component Impact

The potential extension of the BOP pressure testing interval could impact the reliability of BOP components, as it is a modification to the frequency of component proof tests. This section follows the process outlined in Figure 4-1 and begins with a success path assessment to identify components that may be affected by the BOP pressure testing interval modification. This is followed by a reliability assessment of those identified components to determine the potential effects of prolonging time-based pressure test intervals. The success path analysis and reliability assessment provide the framework for both a qualitative and quantitative examination of the likelihood of component failure and the net impact related to an extension of the time-based pressure testing interval.

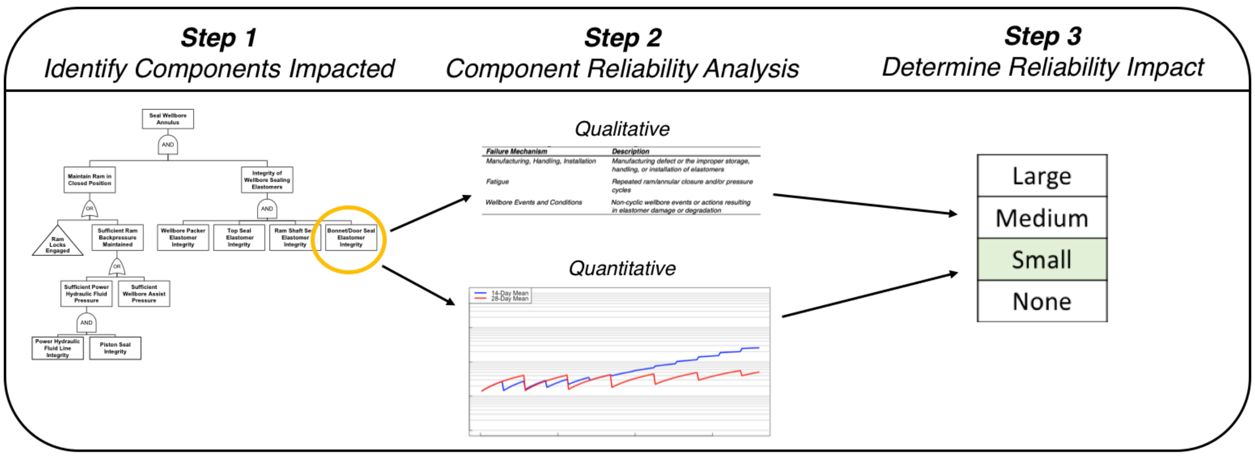

Figure 4-1: Overview of Component Impact Analysis Process

4.1 Success Path Assessment

Recently, Argonne performed a success path assessment of BOP equipment as part of a study regarding blind shear ram reliability [7]. The success path identifies the equipment and actions necessary for successful operation of a system or component during a well control event. Of particular importance for the current study is the success path for the closure of the pipe rams, VBRs, and annulars.

> ***Key Point***
>
> *Successful deployment of the pipe rams, VBRs, or annulars during a well control event requires two general actions:*
>
> 1) *Successful closure of the ram/annular*
> 2) *Successful sealing of the wellbore annulus*

For a pipe ram/VBR or annular to be successfully utilized during a well control event, two main objectives must be met. First, the ram/annular must be successfully closed, and once closed, the ram/annular must successfully isolate pressure by sealing the wellbore annulus. An example success path for a pipe ram illustrating these objectives is shown in Figure 4-2.

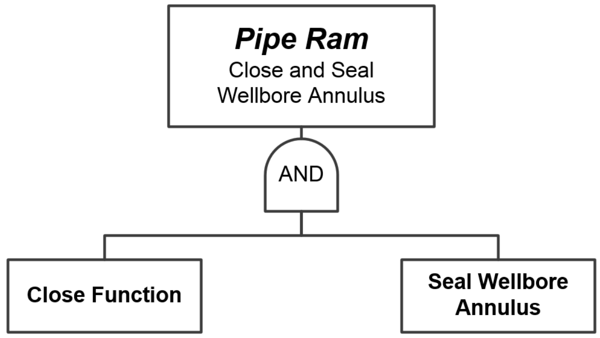

Figure 4-2: Pipe Ram Close and Seal - Success Path

The ***close function*** success path for the ram/annular relies on many systems, as shown in Figure 4-3 for a subsea BOP. As previously highlighted in Figure 2-1, the close function includes the rig panels, the surface control system, the mux system, the subsea control pods, power hydraulic fluid piping, the valving on the BOP, and the ram hardware. Each of these systems comprises many subcomponents and subsystems, while also relying on associated support systems, such as the rig's AC power and hydraulic power units (HPUs). A complete success path for the ***close function*** pathway can be found in Appendix B.

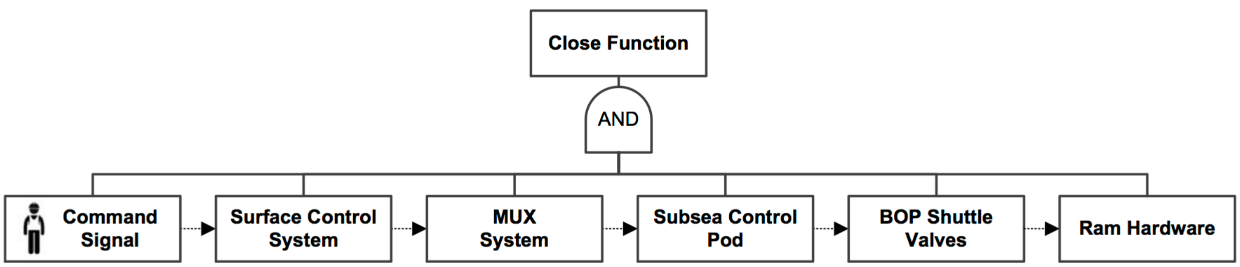

Figure 4-3: Close Function - Success Path

In contrast, the success path to ***seal the wellbore annulus*** and successfully isolate and hold pressure involves fewer systems and components. As shown in Figure 4-4, this success path can be separated into two main sections: maintaining the ram in the closed position and isolating wellbore pressure through successful performance of the wellbore seals.

Maintaining the ram in the closed position can be typically be achieved through one of two pathways: Either the ram locks engage, mechanically preventing the movement of the ram, or there is sufficient backpressure on the ram to keep the ram in the closed position. The ram backpressure can be from the power hydraulic fluid, from wellbore assist, or a combination of the two. The success of the power hydraulic fluid to maintain backpressure relies on the fluid lines and the ram piston seal elastomer.

The ***integrity of the wellbore sealing elastomers*** includes a collection of ram seals that isolate wellbore pressure. As previously shown in Section 2.1, these include the wellbore packer seal, the top seal, the ram shaft seal, and the bonnet/door seal[12]. It is important to note that this portion of the success path *does not* include elastomer seals that are only necessary for the containment of

[12] Depending on the specific design of the ram/annular, there may be more/less wellbore sealing elastomers.

power hydraulic fluid, whether in the open or close chamber, but only seals that contain wellbore pressure.

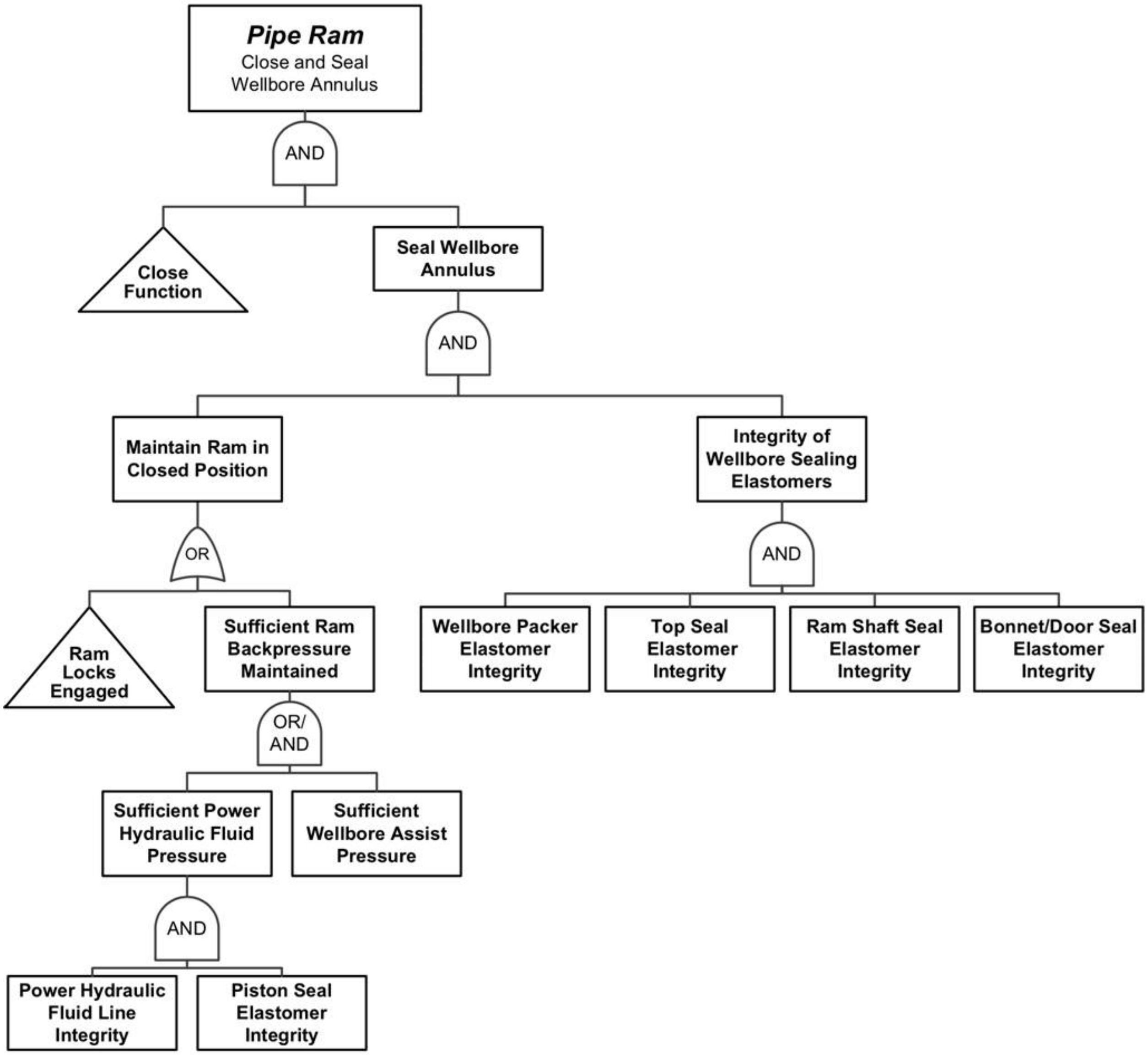

Figure 4-4: Seal Wellbore Annulus – Success Path[13]

> ***Key Point***
>
> *All of the components and systems of the success path necessary for closure of the ram/annular are proof tested through the weekly function test.*

As discussed in Section 2.2.2, there are two types of tests performed utilizing the non-shear rams and annulars: function tests and pressure tests. Although function tests and pressure tests are typically considered separate, a pressure test is naturally also a function test, as the ram/annular must first be closed

13 An "OR/AND" gate is shown for ***sufficient ram backpressure maintained*** since success may be accomplished through either pathway or through a combination of the two, depending on the situation. The triangle associated with ***ram locks engaged*** would transfer to a ram lock-specific success path.

before the pressure test may begin. Figure 4-5 highlights which parts of the success path are proof tested with each test.

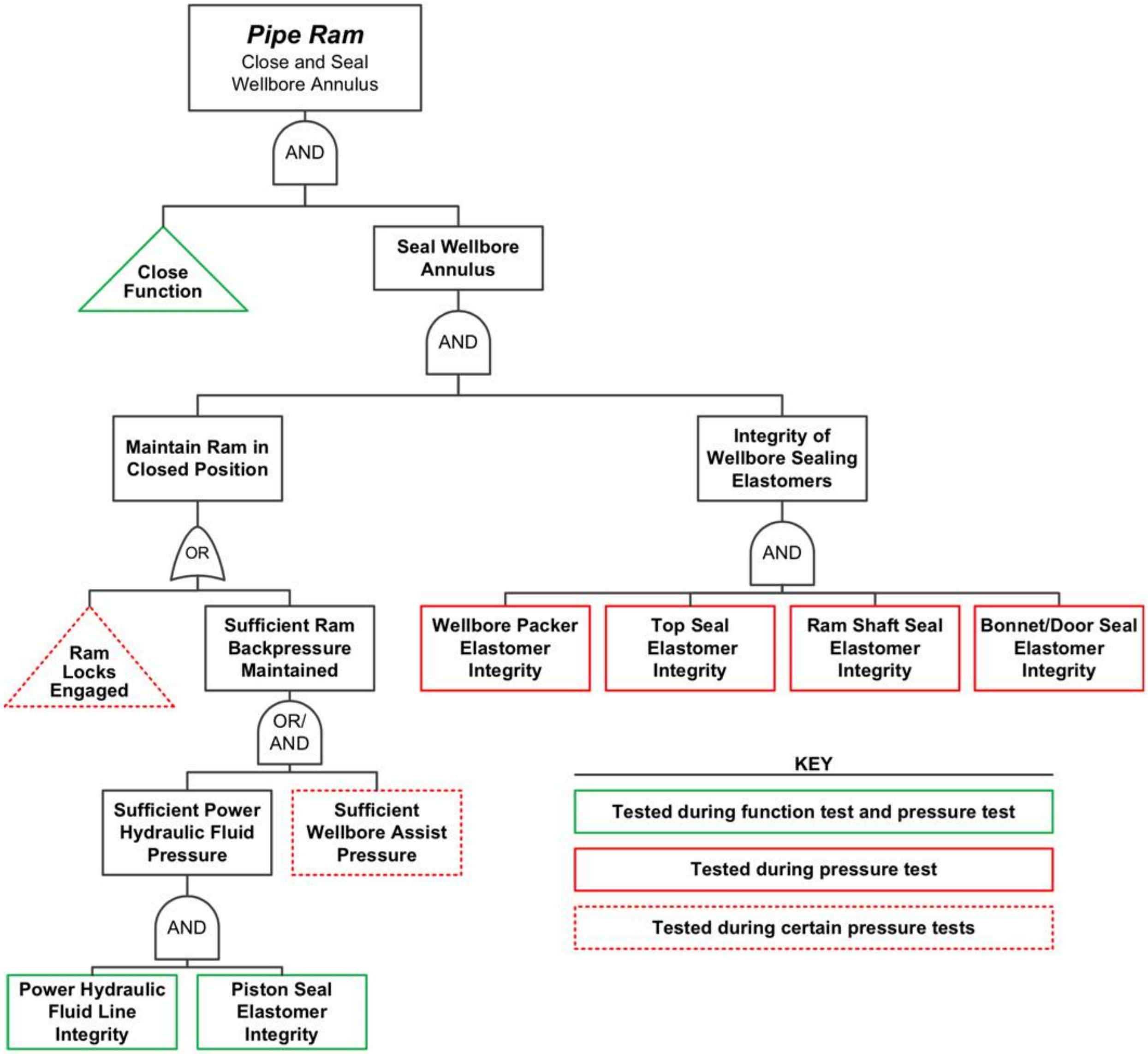

Figure 4-5: Pipe Ram Close and Seal - Success Path, with Testing Coverage[14]

All elements of the ***close function*** are included in the function tests and pressure tests. However, many of the components comprising the ***seal wellbore annulus*** portion of the success path are only proof tested through the pressure test, as the function test does not apply a pressure differential in the wellbore annulus. All of the elastomer seals that are required to seal the wellbore annulus are only tested through the pressure test. On the section of the success path that maintains the ram in the closed position, the rams locks and wellbore assist are tested through

[14] Pressure testing is not considered a proof test of **sufficient wellbore assist** for the pipe rams and VBRs for all pressure tests, as API 53 mandates that ram-type BOPs with locks must have their locks engaged during certain pressure tests (6.5.4.9, 7.6.6.9), and CFR (250.1624, 250.1610, 250.735) requires locks on pipe rams and VBRs.

some, but not all, pressure tests. For example, API 53[15] requires that the power hydraulic fluid lines be vented and the ram locks engaged for initial or pre-deployment tests, but not the time-based pressure test. In addition, wellbore assist may only provide ample closing pressure when the pressure differential across the closed ram is sufficiently high.

As demonstrated in Figure 4-5, the primary group of components that would be impacted by an extension of the BOP pressure test would be the wellbore sealing elastomers (packer seal, top seal, ram shaft seal, bonnet/door seal, etc.), as they are not proof tested through the weekly function test. The weekly function test is not a proof test of these components since no pressure differential is applied in the wellbore. Therefore, following the analysis procedure outlined in Figure 4-1, the wellbore sealing elastomers are selected for the component reliability analysis to determine the impact of extending the time-based BOP pressure testing interval. This analysis is documented in the following section.

Key Finding

The main components of the success path impacted by an extension of the time-based BOP pressure testing interval are the wellbore sealing elastomers, as they are not proof tested by the weekly function test.

[15] See 6.5.4.9 for surface BOPs and 7.6.6.9 for subsea BOPs.

4.2 Impact Assessment – Wellbore Sealing Elastomers

Since the success path assessment in Section 4.1 identified the wellbore sealing elastomers as a key component impacted by an extension of the time-based pressure testing interval, this section provides additional detail on the reliability of wellbore sealing elastomers. This includes information on elastomer manufacturer testing protocol, operational data on the degradation of elastomers, and a reliability assessment of the elastomers when considering different time-based pressure testing intervals.

4.2.1 Elastomer Qualification

Preoperational manufacturer testing requirements for BOP elastomers[16] are defined in ANSI/API Spec 16A [16], "Specification for Drill Through Equipment." Currently, CFR incorporates by reference the 3rd edition of API Spec 16 A, which was published in 2004 and reaffirmed in 2010. However, the 4th edition of API Spec 16A was published in October 2017 and contains several key differences when compared to the 3rd edition. Of most importance for the current study is the inclusion of two levels of Performance Requirements, PR1 and PR2.

> **Key Point**
>
> *The 4th edition (2017) of API 16A now includes two levels of minimum performance criteria for ram and annular manufacturer testing.*

The PR level determines the minimum performance criteria for each of the required validation tests of the BOP elements, such as tests related to sealing characteristics, fatigue, stripping, hang-offs, etc. In general, the PR1 requirements are consistent with those found in the 3rd edition, with only minor modifications. However, the PR2 level has enhanced qualification testing and more stringent minimum performance criteria. If a ram/annular satisfies the PR2 requirements, it also meets PR1 requirements.

A detailed comparison of the PR1 and PR2 level minimum performance criteria can be found in Appendix C. Table 4-1 shows an example of the minimum performance criteria for fixed bore pipe rams. As demonstrated in the table, for many tests, PR2 has quantifiable minimum criteria, while PR1 only has a "reportable" requirement, meaning that the results of the test must only be documented. The values for the minimum number of pressure cycles are based loosely on a year of operational time (assuming one cycle per week for pipe rams and one cycle every two weeks for annulars)

Table 4-1: Minimum Performance Criteria for Fixed Bore Pipe Rams [17]

Test	*PR1 Minimum Performance Criteria*	*PR2 Minimum Performance Criteria*
Sealing Characteristics	*Reportable*	*Reportable*
Fatigue	*Reportable*	*52 Pressure Cycles*
Stripping	*Reportable*	*500 ft*
Hang-off	*Reportable*	*Reportable*
Low Temperature	*3 Pressure Cycles*	*3 Pressure Cycles*
Continuous High Temperature	*N/A*	*10 Pressure Cycles*
Extreme High Temperature	*1 hour hold time*	*1 hour hold time*

[16] API Spec 16A does not apply to the field use or field testing of drill-through equipment.

In addition to the quantifiable minimum performance criteria, the PR2 level also has additional operating manual requirements. Although the PR1 level operating manual requirements include an operational characteristics summary, the PR2 level requirements specify the characteristics and data that must be included pertaining to each validation test. Also, the PR2 level requires recommendations for the inspection of certain components, including non-destructive evaluation, visual inspection, dimensional inspection, etc. The 4th edition also provides additional clarity and transparency regarding certain component tests, such as temperature test performance.

As the 4th edition of the API 16A was recently released, the availability of PR2 qualified components is still limited, but is expected to increase as manufacturers begin implementing 4th edition testing protocol.

4.2.2 Elastomer Failure Mechanisms

As part of the current study, Argonne collected information from industry regarding the degradation and failure of wellbore sealing elastomers. The goal was to determine the likely failure mechanisms[17] of the elastomers during operation. This information would then be utilized in the reliability assessment documented in Section 4.2.4.

> ***Key Point***
>
> *In general, there are 3 main categories of elastomer failure mechanisms:*
>
> 1) *Manufacture Defect or improper handling/installation*
> 2) *Fatigue*
> 3) *Degrading wellbore event/condition*

Based on this analysis, the elastomer failure mechanisms were grouped into three general categories, shown in Table 4-2. The first category is elastomer failure due to manufacturing defect, the improper storage or handling of the elastomer, or the incorrect installation of the elastomer. The second category is elastomer failure due to fatigue from repeated closure or pressure cycles. Lastly, elastomer degradation or damage may occur while the elastomer is within the BOP on the wellhead due to specific wellbore events or actions outside of normal closure and pressure cycling. It is important to clarify that the three potential failure mechanisms are not independent and may result in cumulative damage effects that cause elastomer failure.

Table 4-2: Categories of Wellbore Sealing Elastomer Failure Mechanisms

Failure Mechanism	***Description***
Manufacturing, Handling, Installation	*Manufacturing defect or the improper storage, handling, or installation of elastomers*
Fatigue	*Repeated ram/annular closure and/or pressure cycles*
Wellbore Events and Conditions	*Non-cyclic wellbore events or actions resulting in elastomer damage or degradation*

Through discussions with industry and reviews of industry data, each potential failure mechanism was examined in greater detail. Premature elastomer failure may result from a defect caused during the manufacturing process or due to degradation caused from improper handling or installation.

[17] As defined in ISO 14224 [18], failure mechanisms are the "physical, chemical, or other processes which has led to a failure." A failure mechanism differs from a failure mode in that a failure mode is the "manner of failure," such as a motor failing to start. In general, failure mechanisms are the cause of a failure mode.

This could be the result of deviations from OEM handling and storage protocol. Typical OEM elastomer protocols will include limitations on factors such as temperature, heat sources, direct sunlight, tensile stress, and ozone and ionizing radiation. Similarly, deviations from OEM guidance regarding installation can also result in reduced elastomer reliability.

> **Key Point**
>
> *Current industry practice is to replace BOP wellbore sealing elastomers well before the expected end-of-life from fatigue due to the costs associated with unplanned BOP repairs.*

The fatigue failure mechanism is due to the repeated use of the elastomer through ram/annular closures and subjection to pressure cycles. Repeated use causes the formation and growth of cracks within the elastomer. The planned service life of elastomers is typically based on the number of use cycles. The general current practice of operators in the GoM is to replace wellbore sealing elastomers on the BOP well before the expected end of service life. The reason for this is that the failure of an elastomer during operation (either during a pressure test or as part of a wellbore operation) is likely to result in rig downtime, whether to disassemble a surface BOP or the need to pull a subsea BOP to the rig for elastomer replacement. This process can be costly to the operators as rig time is a major expense of the drilling process. Instead, operators will typically replace all BOP elastomers any time that the BOP has been pulled to the rig[18]. Although the BOP elastomers are expensive components, in comparison to the need to pull a subsea BOP during operation, the cost is generally seen as acceptable.

> **Key Point**
>
> *Certain wellbore conditions or well operations can cause significant degradation to wellbore sealing elastomers.*

The final failure mechanism category is the occurrence of damaging or degrading events while the elastomer is deployed on the BOP. These are events outside of the typical closure/pressure cycles and include a variety of wellbore conditions and well operations. Industry has defined a set of well conditions and well operations that can lead to premature degradation of the wellbore sealing elastomers. Table 4-3 provides a detailed description of many of these degradation factors.

In terms of well conditions, the largest degradation factors are the presence of sour gas or carbon dioxide, the use of brines (or other wellbore fluids) incompatible with the elastomers, and the exposure of the elastomer to temperatures or pressures beyond the designed capabilities (see ref. [19] for additional detail on these factors). In terms of well operations, hang-offs and stripping are known degradation events and often have defined operational limits. In addition, well control events and milling operation also have the potential to cause elastomer damage/degradation.

[18] If the BOP has been subsea for a very short amount of time, some operators may not replace the BOP elastomers. However, this is only done if the elapsed time period (or operational period) is considered to be far below the expected service life of the elastomers.

Table 4-3: Elastomer Degradation Factors

Factor	Description
Well Conditions	
Hydrogen Sulfide – H_2S (Sour Gas)	*H_2S is a highly corrosive gas that reacts and degrades many types of elastomers.*
Carbon Dioxide – CO_2	*CO_2 can result in swelling and rapid gas decompression damage[1].*
Brines	*Brines, such as calcium, sodium, and ZnBr2, can increase elastomer hardness.*
High and low temperatures and/or pressures	*High temperatures typically soften elastomers, while low temperatures will harden elastomers.*
Well Operations	
Hang-offs	*Resting a tool joint on a pipe ram to suspend the weight of the drill string below the BOP. Could result in damaged pipe ram elastomers.*
Stripping	*Pulling the drill string through a closed BOP element (typically annular).*
Well control events	*Including emergency pipe shearing events or other uncontrolled well flow events (kicks).*
Milling	*Cutting through an obstruction in the wellbore. Can create debris in the wellbore annulus that collects in or damages BOP elements.*

[1] If CO_2 permeates into the elastomer while at high pressure, it could cause explosive decompression as pressure is reduced.

4.2.3 Review of Past Elastomer Failures

In addition to discussions with industry, a review of past BOP studies and recent well activity reports (WARs) was conducted in an attempt to determine how elastomer failures have been identified and which, if any, of the wellbore sealing elastomers failure mechanisms is dominant. This information is then used to inform the reliability models described in Section 4.2.4. First, an assessment was made of several past studies on the failure of rams and annulars over various time periods. These three studies, detailed in Table 4-4, cover a time period from 1997 to 2009 and focused on subsea BOPs in the GoM. A review was conducted of the pipe ram, VBR, and annular failures documented in these reports. Specific focus was given to failures that resulted in wellbore leakage through a closed element into the wellbore annulus or leakage from the wellbore through the ram/annular body into the environment.

Table 4-4: Summary of Past BOP Component Reliability Studies

Study	Description
SINTEF – Reliability of Subsea BOP Systems for Deepwater Application (Phase II DW) [6]	• *1997 – 1998* • *83 wells (depth > 400m – 1312ft)* • *Subsea BOPs* • *US GoM OCS*
WEST – Blow-out Prevention Equipment Reliability Joint Industry Project (Phase I – Subsea) [4]	• *2004 – 2006 (plus others)* • *239 wells (depth > 1219m – 4000ft)* • *Subsea BOPs* • *US GoM OCS*
ExproSoft – Reliability of Deepwater Subsea BOP Systems and Well Kicks [13]	• *2007 – 2009* • *259 wells (depth > 612m – 2000ft)* • *Subsea BOPs* • *US GoM OCS*

An attempt was made to classify the failure mechanisms documented in the reports and, if possible, identify how the failure was discovered. The identification pathway was grouped into the categories shown in Table 4-5, which are aligned with the pressure test types described in Table 2-4. However, it should be noted that not all failures documented in the reports were described in sufficient detail to resolve this information.

Table 4-5: Elastomer Failure Identification Categories

Identification Method	*Description*
Stump Pressure Test	*Pressure test performed on rig before running BOP*
Installation Pressure Test	*Pressure test performed after BOP is connected to wellhead*
Pressure Test After Certain Events	*Pressure test performed after a potentially degrading or damaging event has occurred*
During Operation	*Failure identified during well operations, not a pressure test*
After Casing/Liner Pressure Test	*Pressure test performed after running casing/liner*
Time-Based Pressure Test	*Pressure test conducted due to the passage of time while on the wellhead*

Table 4-6 contains a summary of the failures described in the reports. A complete description of the categorization of each failure can be found in Appendix D. In general, it appears that the majority of failure for elastomers on both the annulars and pipe rams/VBRs were identified during the stump and installation pressure tests. Additional failures were identified during operations, pressure tests after certain events, and pressure tests after running casing and liner. The time-based pressure test generally identified the fewest failures, with no clear cases of pipe ram/VBR failure identification.

Table 4-6: Annular/Ram Failures Identified in Past BOP Component Reliability Studies[19]

Failure Identified	*SINTEF Phase II*		*WEST - JIP*[a]		*ExproSoft*		*TOTAL*	
	Ann.	*Pipe/VBR*	*Ann.*	*Pipe/VBR*	*Ann.*	*Pipe/VBR*	*Ann.*	*Pipe/VBR*
Stump/Install PT	2	0	4	7	7	8	13	15
Stump	1	0	4	7	0	4	5	11
Install	1	0	0	0	7	4	8	4
PT After Event	0	0	1	2	0	1	1	3
During Operation	2[b]	0	2	2	2[b]	0	6	2
After Casing/Liner PT	1	2	0	1	0	3	1	6
Time-Based PT	0	0	2	0	2	0	4	0

[a] Identification of four failures unclear.
[b] Failure identified during or immediately after well control operation, including stripping.

In addition, there were several noteworthy events identified during the data review of past studies. There were several cases of apparent common cause failure (CCF) of elastomers on multiple BOP elements at the same time. In two separate instances, two annulars failures were discovered during a wellhead installation pressure test. This could be an indication that there was a CCF mechanism of improper handling or installation of the annular elastomer. In another case, two annulars failures were discovered during a pressure test after the running of casing, which could

19 Failures only include wellbore leakage past a closed BOP element, or wellbore leakage through the BOP element body to an area outside of the wellbore.

signify that a common event or condition occurred that impacted both elements. Of the documented VBR failures, at least three were noted to be BOP test rams, which are not used for wellbore operations and are subject to many more pressure cycles than the other BOP elements (as described in Section 2.2.2). The potentially degrading events that resulted in the performance of a pressure test included kicks and prolonged milling operations.

A review of 2011-2017 WAR data was performed to assess elastomer failure trends in the post-Macondo GoM period. The initial review focused on WAR "significant event" reports, which includes a category for well control equipment failures. As shown in Table 4-4, since the current study is not solely focused on deepwater wells, the number of wells included is much greater than the three past studies and involves both surface and subsea BOPs.

Table 4-7: Summary of Post-Macondo WAR Data

Data	***Description***
Well Activity Reports (WAR)	• *2011 – 2017* • *~1800 wells* • *Surface and Subsea BOPs* • *US GoM OCS*

It should be noted that it was difficult to identify and assess failures in the WARs due to several factors. First, not all failures were properly noted as "Significant Well Events – Well Control Equipment Failure," in the WARs. Second, WARs do not use consistent terminology regarding failures of the BOP to seal the wellbore. For example, operators may use terminology such as "fail to test," "fail to hold pressure," "did not test," "did not seal," or "leak present" all to signify that a pressure test failed. For those failures that occurred during a pressure test, the reason for the pressure test, such as a time-based test or after casing/liner, is rarely stated and must be deduced from examining recent WARs for the rig under consideration. In addition, many times there is little information provided regarding diagnosing the cause of the leak or failure, which makes it difficult to separate control system issues from wellbore sealing elastomer failures. Therefore, the number of WAR failures identified during this period may underrepresent the total number of wellbore sealing elastomer failures. Recognizing these data deficiencies is vitally important for the quantitative reliability analysis reviewed in Section 4.2.4 and Appendix E.

The results of the WAR data significant event review can be found in Table 4-8. For the annulars, the distribution of identified failures is very similar to that found in the three past studies, with the majority of failures identified through the stump/installation pressure tests. There is a higher proportion of failures identified by the pressure test after casing/liner, but the time-based pressure test remains the pressure test with the fewest identified failures. There were fewer pipe ram and VBR failures reported in the significant event WAR data and they were more equally distributed between the install/stump pressure tests, pressure tests after certain operations, and the time-based pressure tests. However, in total, the number of failures identified by the time-based pressure test is still small given the number of wells.

Table 4-8: Annular/Ram Failures Identified in Post-Macondo WAR Data[20]

Failure Identified	Current Study	
	Ann.	Pipe/VBR
Stump/Install PT	18	6
Stump	3	1
Install	15	5
PT After Event[1]	5	5
During Operation[2]	2	0
After Casing/Liner PT	8	0
Time-Based PT	5	6

[1] Events inducing a PT included kicks, milling, and stuck drill strings.
[2] Potentially underrepresented due to the difficulty in distinguishing these failures in the database.

The failures were then divided by rig type since the WAR data represents both subsea and surface BOPs. Although it is difficult to estimate the total number of BOP hours for each rig type, the data is helpful to identify any gross trends in failures. As shown in Table 4-9, failures are distributed across all rig types, including deepwater drillships and shallow-water jack-ups. It does not appear that the failure of wellbore sealing elastomers is limited to only subsea or surface BOPs.

Table 4-9: Type of Rig for Post-Macondo WAR Data Failures[20]

Rig Type	Current Study	
	Ann.	Pipe/VBR
Jackup	11	7
Drillship	11	3
Semi-submersible	12	6
Platform	2	0
Deepwater Platform	4	2

Key Finding

A review of pipe ram, VBR, and annular elastomer failures found that failures are rare events and the majority of failures are identified during stump and installation pressure tests or are associated with degrading events while on the wellhead. The time-based pressure test, although by far the most frequent pressure test, identified the fewest failures.

When reviewing past elastomer failures and examining the impact of extending the BOP pressure test interval on elastomer reliability, it is important to consider the redundancies that are required in BOP stack configuration. CFR[21] requires that both surface and subsea BOPs contain at least two pipe rams[22] and one annular. Therefore, there is redundancy in the availability of these

[20] WAR data from 2011 – 2017. Failures only include wellbore leakage past a closed BOP element, or wellbore leakage through the BOP element body to an area outside of the wellbore.

[21] §250.733 – Surface, §250.734 – Subsea.

[22] "The two BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, except for tubing with exterior control lines and flat packs, a bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools."

components, if one were to experience a wellbore sealing elastomer failure. In additional, there is no modification assessed in this study that would impact these redundancy requirements. However, there are several important factors to consider when crediting this redundancy for well control operations.

First, depending on the particular well control scenario, the timing of the events may make it difficult to employee a second BOP element if the first one has failed. For the successful deployment of a secondary pipe ram/annular, the operating crew will first have to recognize the failure of the primary element, diagnose the situation, and activate the second element before the well has reached a state where the BOP element is no longer effective. This process could be difficult to achieve under some circumstances.

The second factor to consider is the possibility of CCF. As discussed above, there appears to be several past examples of multiple pipe rams/VBRs/annulars failing due to a common cause factor. It is possible that both of the dominant elastomer failure mechanisms, degrading wellbore events or conditions and improper install/handling, may impact multiple BOP elements simultaneously. This highlights the importance of properly understanding and recognizing the dominant failure mechanisms.

Both of these factors should be recognized and considered when operators choose the BOP configuration for a well. Specifically, API 53[23] requires that a documented risk assessment be performed to assess BOP arrangement and identify ram placements and configurations for well control management.

4.2.4 Elastomer Quantitative Reliability Analysis

As described in Section 2.2, the BOP pressure test is primarily a proof test of the wellbore sealing elastomers. It is the only proof test of these seals, since function testing alone does not provide insight into their sealing and pressure-isolating capability. Determining the impact of extending the time-based pressure test interval can be complex. A detailed reliability assessment of the wellbore sealing elastomers was performed with a focus on the effect of modifications to the pressure testing interval. A complete description of the reliability model and the analysis is provided in Appendix E, with an overview of the key findings presented here.

> ***Key Point***
>
> *The use of the term "standby" component refers to the fact that the BOP ram/annulars on the wellhead are not in constant use. It does NOT refer to a backup BOP stack on the rig that is not installed on the wellhead.*

The wellbore sealing elastomers of the pipe rams, VBRs, and annulars are considered "standby" components, meaning that they are not in continuous operation, but instead are placed into operational standby until called upon to perform an action. It is important to highlight that the terminology "standby" component refers to those BOP ram/annulars on the wellhead that are not in constant use. It does not refer to the backup BOP stack on the rig that is not installed. As detailed in Appendix E and outlined in Figure 4-6, a reliability model was constructed that attempts to capture the multiple contributors to the probability of wellbore sealing elastomers failing to perform when demanded, referred to

[23] 6.1.2.7/6.1.2.12/6.1.2.13 – Surface, 7.1.3.1.5 – Subsea.

here as PFD (probability of failure on demand). This includes contributions from factors that could cause the elastomers to fail while in standby and contributors that could result in elastomer failure during the demand itself. The model includes parameters related to both contributors and uses parameter values that are estimated based on failure data from past studies.

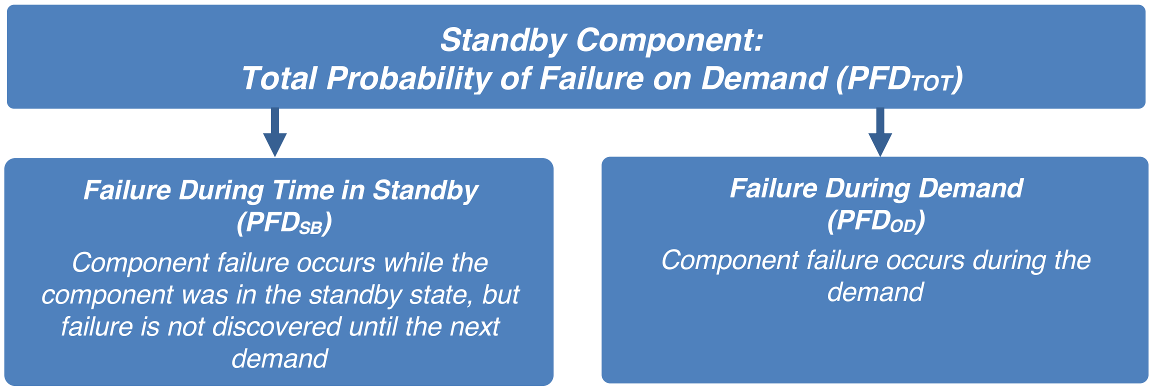

Figure 4-6: Standby Component Failure Contributors

Using the reliability model, three scenarios were examined that represent failures from the three main failure mechanism categories described in Section 4.2.2. For each scenario, the impact of extending the time-based pressure testing interval was assessed. **It is important to highlight that the main purpose of the quantitative reliability analysis is not the determination of the absolute values for PFD, but to compare the magnitude of the multiple, competing failure mechanism effects and to provide insights regarding how changes in the pressure testing interval may impact the PFD.**

Table 4-10: Scenario #1 Summary Results

Scenario #1	
Scenario Description	*Elastomer compromised due to manufacturing defect or improper installation/handling*
Reliability Analysis Results	*Vital actions for reducing impact of failures from this mechanism:* ○ *Proper quality controls regarding elastomer manufacturing and handling/installation by customer.* ○ *Continued use of stump and installation pressure tests as screening mechanisms for identification of compromised elastomers.* *Further pressure testing cannot repair irreversible elastomer damage.*
Impact on Elastomer Reliability of Extending Time Based Pressure Testing Interval	***Minimal*** *– Damage occurs before elastomers enter service on wellhead and stump and installation pressure tests are key to identification.*

The first scenario analyzed with the reliability model was the event where a wellbore sealing elastomer is compromised due to a material defect or damage from improper handling or installation. The findings of this analysis are summarized in Table 4-10. The first step of the analysis was to determine how these events impact the contributors to the elastomer PFD.

For this case, the damage from the pre-operational event likely causes an increase in the probability of failure during the next demand. This failure mechanism does not appear to increase the probability of failure while in standby, as failures are being identified during the stump and installation pressure tests, which occur before the elastomer enters its time in standby on the wellhead. In addition, when examining past data, the total number of failures that were identified after a successful installation pressure are less than those that were found during the stump and installation test. Therefore, even if all of the failures identified after a successful installation pressure test could be attributed to an increase in the standby failure rate (which does not appear to be the case), the impact on standby failure still appears to be smaller than the increase in the probability of failure during the next demand (the stump/installation test). This fact also indicates that the stump and installation tests are doing an adequate job of identifying and screening damaged elastomers before they enter service on the wellhead.

Since pressure tests do not repair damaged elastomers, but only identify whether the damage is of sufficient severity to cause a degradation in performance, the subsequent time-based pressure test interval after the installation pressure test likely has minimal impact on elastomer PFD for this scenario. It is a common saying that a manufacturer cannot "test-in" quality to a product after it is built. In much the same way, the time-based pressure test cannot "test-in" reliability into a previously damaged component. Instead, the primary method in which failures from this mechanism can be avoided is through prevention.

Quality controls during manufacturing, handling, and installation are the key pathways to reducing failures from this failure mechanism. Quality controls should be a seamless process from manufacturing to transport/handling and eventual installation. This includes proper quality controls during the manufacturing process to screen products that could contain defects. On the customer side, it is necessary to understand manufacturer recommendations regarding elastomer storage, handling, and installation.

Table 4-11: Scenario #2 Summary Results

Scenario #2	
Scenario Description	*Elastomer successfully passes stump and installation pressure tests and enters service on the wellhead, but then experiences a damaging or degrading wellbore event/condition.*
Reliability Analysis Results	*Vital actions for reducing impact of failures from this mechanism:* • *Knowledge and avoidance of damaging/degrading events and conditions.* • *Prompt identification if a damaging/degrading event has occurred.* • *Pressure test after event to determine if elastomer has failed or suffered significant degradation.* *Further pressure testing cannot repair irreversible elastomer damage. Data indicates that such events do not typically cause an appreciable increase in the standby failure rate.*
Impact on Elastomer Reliability of Extending Time Based Pressure Testing Interval	***Minimal*** *– Prompt pressure testing after the event is preferred to relying solely on the time-based pressure test for identification as to minimize the time period with a failed elastomer in service.*

The second scenario analyzed involves an elastomer that has successfully passed the stump and installation pressure tests, but is then subjected to an unusual damaging or degrading event while in service on the wellhead. This scenario aligns with the last failure mechanism category in Table 4-2, such as one of the wellbore events or conditions described in Table 4-3. The results are summarized in Table 4-11. As with the previous scenario, the first task is to determine how the event impacts the contributors to the elastomer PFD.

The damaging wellbore event may increase the probability of failure during the next demand, the standby failure rate, or both. An examination of past data appears to indicate that the consequences of such an event primarily impact the first factor, the probability of failure during the next demand. Reviewing the failures in Section 4.2.3, there are a significant number that were identified either during a degrading event or by a pressure test immediately after a degrading event. There are more failures identified by these two pathways than by the time-based pressure test. This indicates that elastomer failures induced from these events typically occur quickly and not at a later time. It could be that the degrading and damaging events are falling into two general categories. Either the event is severe enough to cause immediate failure or the events are of insufficient severity to have an appreciable subsequent impact on the standby failure rate.

As with the previous scenario, subsequent pressure tests cannot repair the damage that has occurred from the event, but only identify whether the damage is of sufficient severity to cause a degradation in performance. Once a pressure test is performed immediately after the event, there is little additional benefit to frequent time-based pressure tests, as the change in standby failure rate appears small and further pressure testing will cause additional elastomer damage (from cumulative fatigue damage). The time-based pressure test alone should not be relied upon to identify failures from this mechanism, as that may result in several days of operational-time passing before the next testing cycle. Prevention and proper identification are the keys to reducing failures from this mechanism.

First, the wellbore events and conditions that can damage the wellbore sealing elastomers should be well documented and subsequently avoided. Second, if such an event occurs, it needs to be identified by the operators immediately. Lastly, once identified, a pressure test should be performed to determine whether the event was of sufficient magnitude to cause fatal damage or observable degradation. In general, these factors are known to industry and they appear to do an acceptable job implementing them. However, as described in Section 2.2.2, guidance on these events is not as clear or refined as the requirements related to stump/installation pressure tests or time-based pressure tests. As outlined in Table 4-11, assuming correct identification of the degrading/damaging event occurs and a subsequent pressure test is performed, there appears to be minimal impact of changes to the time-based pressure test interval on elastomer reliability for this scenario.

Table 4-12: Scenario #3 Summary Results

Scenario #3	
Scenario Description	*Elastomer successfully passes stump and installation pressure tests and enters service on the wellhead. No atypical damaging or degrading wellbore events/conditions during time on wellhead, but the elastomer is subjected to repeated time-based pressure tests.*
Reliability Analysis Results	• *The time-based pressure test improves confidence in elastomer reliability by demonstrating that the component has not failed during the previous time in standby, but also increases cumulative fatigue damage with each pressure cycle* • *Available data appears to indicate that the standby failure rate is low, which implies a small net PFD benefit when cumulative fatigue damage is reduced by extending the time-based pressure test interval.* • *Uncertainties in the data, and therefore in the modeling results, could be reduced through further industry data collection efforts.*
Impact on Elastomer Reliability of Extending Time Based Pressure Testing Interval	***Minimal*** *– Extension of the time-based pressure test interval has minimal impact on elastomer reliability, as the main benefit of the test is the identification of failures that occur during standby, but such events are rare (i.e., the standby failure rate is low).*

The last scenario considered is the most common and also the most difficult to assess. In this scenario, the elastomer successfully passes the stump and installation pressure tests and enters service on the wellhead. No unusual damaging or degrading wellbore events occur and the elastomer undergoes repeated pressure test cycles due to the passage of time. This results in the accumulation of fatigue damage (the third failure mechanism). An overview of the analysis can be found in Table 4-12. For this scenario, there is a balance between cumulative fatigue damage and the time period between pressure tests.

As mentioned at the beginning of this section, elastomer PFD has two components: the possibility of failure while in standby and the possible failure during the next demand. The longer the time period an elastomer is in standby on the wellhead between pressure tests, the higher the probability of failure due to the standby failure rate. Conversely, with each pressure test, fatigue damage accumulates and results in an increase in the likelihood of failure during the next demand. The difficulty in assessing this scenario is determining proper values for the parameters related to the standby failure rate and the accumulation of fatigue damage. Described in more detail in Appendix E, the parameters were estimated based on data from past studies, as there was greater uncertainty regarding the values determined from the post-Macondo WAR data. However, this appears to be a conservative approach (*i.e.,* likely results in an overestimation of failure likelihood) based on a comparison of the two data sources[24]. Utilizing this approach, the standby failure rate appears to be very low, while cumulative fatigue damage may increase quickly, when fatigue life is based on the requirements of API 16A 4th edition, PR2.

The annulars and the pipe rams/VBRs were assessed separately. The PFD was calculated assuming a 180-day period of the BOP on the wellhead, and the PFD was compared for different

[24] See Appendix E for additional details.

time-based pressure testing intervals. For the annulars, the accumulation of fatigue damage has a major impact on the calculated PFD. By the halfway point of the well (~90 days), with a 14-day interval, the time-based pressure test is no longer providing a reduction in elastomer PFD, as the cumulative fatigue damage contribution is larger than that of the standby failure rate. In turn, when the number of pressure cycles is reduced by extending the time-based pressure test interval, the average PFD during the well is also reduced. The results for a 14-, 21-, and 28-day pressure testing interval for the annulars are shown in Figure 4-7. The uncertainty bounds are fairly large due to the high uncertainty regarding the model parameter estimates. However, the mean 21- and 28-day results fall within the margin of uncertainty for the 14-day interval.

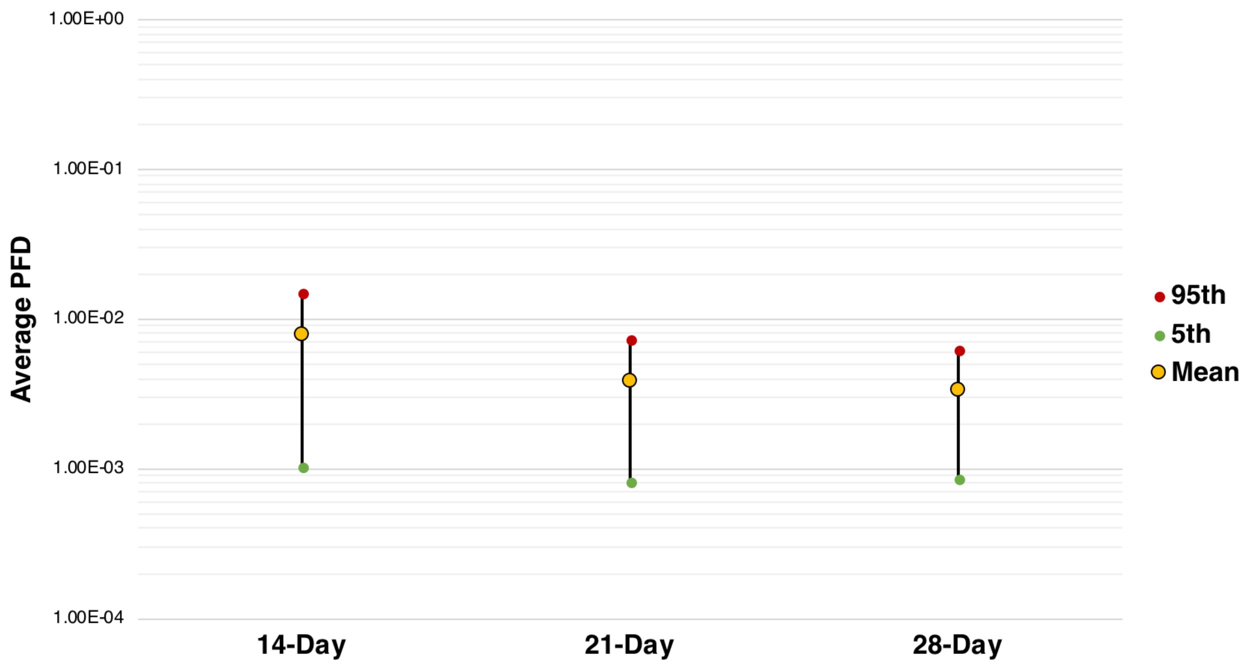

Figure 4-7: Annular – Average PFD with Varying Time-Based Pressure Test Interval[25]

For the pipe rams and annulars, there is a slight difference in the result, as shown in Figure 4-8. The reliability model calculates a slight increase in elastomer PFD when the time-based pressure testing interval is increased. This is due to the way the model addresses elastomer cumulative fatigue damage, which is based on the minimum performance requirements of API 16A 4th edition. The pipe rams and VBRs have a more stringent requirement regarding pressure cycle fatigue than the annulars (52 versus 28 pressure cycles). Therefore, fatigue damage accumulates slower in the analysis of the pipe rams and VBRs and extending the time-based pressure testing interval does not result in an overall reduction in the average PFD. However, it is important to note that the increase in PFD is small and still well within the margin of error of the 14-day result.

25 Average over 180-day well. Uncertainty bounds are 5th and 95th percentile. See Appendix E for additional analysis details.

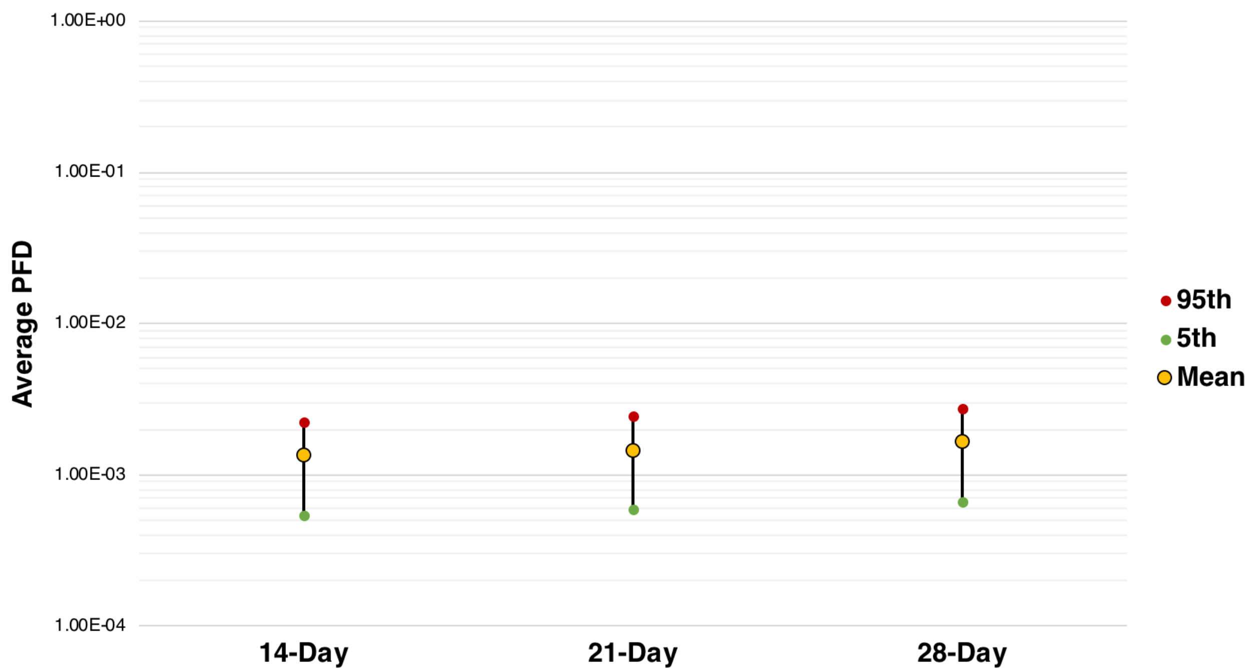

Figure 4-8: Pipe Ram/VBR – Average PFD with Varying Time-Based Pressure Test Interval[26]

There are several key findings from the results of the third scenario analysis. First, the increase in failure probability due to the accumulation of elastomer fatigue damage is highly uncertain as a result of limited available data and the fact that industry routinely replaces elastomers well before their fatigue failure threshold (as described in Section 4.2.2). However, this aspect is vitally important in the reliability model, as an extension of the time-based pressure testing interval impacts the balance between the standby failure rate and cumulative fatigue damage. Model parameter estimates based on the data in Section 4.2.3 indicate that the standby failure rate is low, which then results in a small net PFD benefit when cumulative fatigue damage is reduced.

In general, the results of the quantitative reliability analysis indicate that extending the time-based pressure test interval has minimal impact on the elastomer PFD for this scenario. This is likely a result of the nature of the test and the dominant failure mechanisms of the elastomer. A time-based proof test, like the time-based pressure test, provides the greatest benefit in identifying failures caused by time-based phenomena (specifically in this case, standby time-based phenomena). However, as previous sections have shown, the dominant failure mechanisms of the elastomer are not necessarily time-based phenomena, but are discrete events (material defect, improper handling/install, and degrading events on the wellhead). Therefore, it is not surprising that adjustments in the time-based pressure testing interval do not appear to have a major impact on elastomer reliability, as it is a test that is designed to identify failures from mechanisms that do not appear to be dominant.

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26 Average over 180-day well. Uncertainty bounds are 5th and 95th percentile. See Appendix E for additional analysis details.

Key Finding

A detailed reliability analysis of the wellbore sealing elastomers was conducted for three scenarios:

1) *For an elastomer defect or damage during handling/installation, prevention is the key action followed by screening through the stump and installation pressure tests.*
2) *For degrading events while in service on the wellhead, knowledge and avoidance is key, followed by identification of the event and an immediate pressure test.*
3) *For operation without a degrading event, extension of the time-based pressure testing interval increases uncertainty regarding the status of the component, but this is generally compensated by a reduction in cumulative fatigue damage.*

Taken together, the results of the three scenarios assessed indicate that an extension of the time-based pressure testing interval has minimal impact on elastomer reliability. The central reason for this is that the dominant elastomer failure mechanisms are discrete events and not time-dependent phenomena. Therefore, modifications to a time-based proof test yield little change to elastomer reliability. This finding is generally in line with that of previous studies on the topic[27], which have found minimal impact on BOP reliability due to adjustments in the time-based pressure test.

Key Finding

In general, time-based proof tests provide the most benefit in identifying failures caused by time-dependent phenomena. However, the dominant elastomer failure mechanisms are not time-dependent but occur as discrete events.

There are several additional important findings from the reliability analysis regarding how elastomer failures can be reduced. First, improvements in quality controls could likely yield a reduction in the number of failures due to material defect or improper handling/installation. This includes tracking of elastomers throughout their life cycle, from manufacturing to storage and to eventual use. Similarly, improvements in elastomer manufacturer qualification, such as the quantifiable minimum performance criteria of PR2 in API 16A 4th edition, are helpful in that they set a minimum threshold, but they also give operators confidence in their predictions of elastomer lifetimes. This aids in the planning of BOP maintenance and elastomer replacement.

Second, an improved understanding of the wellbore events and conditions that can degrade elastomers could assist not only in a reduction of the occurrence of these events, but also the identification of when such an event has occurred. Although industry, in general, avoids these events and recognizes when they occur, it is typically dependent on industry best practices and driller knowledge, rather than refined guidance or requirements. This could result in inconsistencies regarding how events are handled and whether pressure tests are performed after events.

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[27] See findings #1 and #2 of ref. [3], "What-If Case 1" of ref. [5], and the recommendation on page 58 of ref. [4].

Key Finding

The results of the scenario analysis indicate several ways in which elastomer reliability could be improved:

- *Improvement in elastomer life-cycle quality controls and further adoption of quantifiable manufacturer minimum testing criteria.*
- *Improved knowledge and guidance regarding wellbore events and conditions that can result in elastomer damage or degradation.*

When quantitatively examining the reliability of the wellbore sealing elastomers, it is important to view the results in context of complete BOP system reliability. There have been several previous studies examining the reliability of BOP rams and annulars (summarized in ref [20]). The findings of the studies have been consistent in that the dominant failure pathway for the complete BOP system, when examining past data, has been components/systems of the control system[28]. This is likely due to the complexity of this system, as it involves many components and subsystems. Although there is redundancy present in several of the systems (hydraulic fluid supply, PODs, etc.), there are also single points of failure (shuttle valves, piping connections, etc.) that can disable the ability to close rams/annulars.

Ref [20] performed a preliminary quantitative assessment of BOP control system reliability. While that quantitative analysis is not completely analogous to the one performed here for wellbore sealing elastomers, it does provide a useful point of approximate comparison. The previous study found the PFD of the control system to close a pipe ram/VBR/annular is approximately 1E-2 (see the "Manual HP Close" results in Section 3.2). This value is almost an order of magnitude higher than the predicted PFD for the wellbore sealing elastomers. In addition, most component failures of the control system impact all BOP elements simultaneously. For example, the loss of a POD will result in the loss of that activation pathway for all rams/annulars. In contrast, wellbore sealing elastomer failures are limited to a single BOP element, unless a CCF event has occurred.

[28] In terms of the success path reviewed in Section 4.1, these would be failures associated with the "closure function" pathway.

4.3 Impact Assessment – Additional BOP Components

Although the success path in Section 4.1 focused on components that are part of the actuation pathway for rams and annulars, there are other systems and components that could potentially be impacted by changes in the BOP pressure testing interval, including choke/kill line valves and BOP bolts. The effect on these components is examined here.

4.3.1 Choke and Kill Lines

As described in Section 2.2.2, a typical BOP pressure testing cycle includes pressure tests of multiple choke/kill valves, such as the line valves, BOP inlet valves, and manifold valves. While some of these components can be pressure tested during drilling operations, extension of the time-based BOP pressure testing interval could result in a reduced pressure test frequency for others. However, the overall potential system impact is affected by both the reliability of the valves and their required configuration, as explained below.

When examining past data from subsea BOPs [4, 6, 13], choke/kill valve failures[29] are rare, especially once the valves have successfully passed the stump and installation pressure tests. Table 4-13 contains an overview of the choke/kill line valve failures identified in these studies. As shown in the table, only 22 choke/kill valve failures were identified during this period, despite a typical BOP stack including 8 to 12 choke/kill valves. The vast majority of the failures were found during the BOP stump or installation pressure test, with only two valve failures identified by the time-based pressure test.

Table 4-13: Choke/Kill Line Valve Failures Identified in Past BOP Component Reliability Studies[29]

Failure Identified	*SINTEF Phase II*	*WEST - JIP*	*ExproSoft*	*TOTAL*
Stump/Install PT	*8*	*6*	*3*	*17*
Stump	*7*	*5*	*0*	*12*
Install	*1*	*1*	*3*	*5*
During Operation	*0*	*1*	*0*	*1*
After Casing/Liner PT	*1*	*0*	*1*	*2*
Time-Based PT	*1*	*1*	*0*	*2*

In addition, the choke/kill isolation valves at the BOP are redundant components, with two valves placed in series at each BOP inlet. This is a requirement of CFR 250.443 [21] and API 53 7.2.3.2.9 [10]. For uncontrolled flow through the choke/kill lines to occur, both valves would have to fail. If uncontrolled wellbore flow was able to enter the choke and kill lines, there is additional valving in the choke and kill manifolds that could also be used to halt flow [4].

[29] Failure refers to either internal leakage through a closed valve, or leakage from within the valve line externally to the environment; leakage of power hydraulic fluid that operates the valve is not included.

Taken together, the high reliability of the choke/kill line valves coupled with the required, direct redundancy of the system design results in a low probability of wellbore leakage through this pathway. The extension of the pressure testing interval for the choke/kill valves appears to have minimal impact on system reliability due to these characteristics.

Key Finding

The high reliability of the choke/kill valves, coupled with the direct redundancy in the system design required by both regulation and standards, results in a low probability failure pathway. Therefore, an extension of the pressure testing interval for the choke/kill line valves would likely have minimal impact on system reliability.

4.3.2 BOP Bolts

Another potential concern with the extension of the pressure testing interval is the possible impact on the identification of BOP bolting failures. Although it is not the primary intent of the BOP pressure test, the pressurization of the wellbore within the BOP during a pressure test could expose failures in critical BOP bolts.

A series of recent BOP bolt failures resulted in a 2016 BSEE Safety Alert to GoM operators [22]. In response to the safety alert, API and industry developed a proposed action plan, outlined in Table 4-14. The steps included the definition of "critical bolting" and the voluntary adoption of API 20 E/F for critical BOP bolting. However, the transition to the upgraded bolts and bolting standard will take some amount of time to implement. In response, BSEE inquired into what interim actions could be taken to confirm the integrity of BOP bolting before replacement occurs. API stated that the BOP pressure tests, specified under API 53, verify the integrity of bolted connections [23].

Table 4-14: API March 31st, 2016 Proposed Action Plan [24]

Action	***Description***
a)	*Defined "critical bolting" as bolting that the failure of which could result in loss of containment of wellbore fluids to the environment*
b)	*Voluntary industry adoption of API 20 E/F for critical BOP bolting*
c)	*Voluntary industry upgrade of critical bolting with hardness > 35 HRC*
d)	*Enhanced QAQC of 3rd party manufactured bolting (i.e., sampling, 20 E/F requirements)*
e)	*Updated make-up procedures, with additional engineering rigor and oversight*
f)	*Elimination of electroplated Zinc coatings*
g)	*Enhanced failure reporting with wider distribution*
h)	*Consistent with the direction of API standards work*

Since that time, industry has made significant progress in the implementation of the action plan (see industry progress update in ref [25]). As progress continues, the need for the BOP pressure test as an interim mechanism for the identification of critical BOP bolting failures should be reduced. In general, the BOP pressure test should not be viewed as an integral proof test of critical BOP bolts, as that is not the primary intention of the test and it is not designed to specifically address that need. Due to the critical nature of the BOP bolts, and the infrequency of their failures, the optimal pathway to improve bolting reliability is not through proof testing of in-service bolts, but through proper and rigorous qualification and procedures, as outlined in the API action plan. Therefore, the impact of an extension of the time-based BOP pressure test will have minimal impact on the identification of BOP bolting failures, assuming that the API action plan has been implemented.

Key Finding

While the BOP pressure test has been identified as an interim action to verify bolting integrity during the implementation period of the API bolting action plan, due to the nature of BOP bolts and the infrequency of their failures, the optimal pathway to improve reliability is not through increased proof-testing of in-service bolts, but through proper and rigorous qualification.

5 Potential Path Forward

Based on the findings of Sections 3 and 4, a potential path forward was developed that outlines recommendations regarding the time-based BOP pressure testing interval and possible requirements to ensure operational safety. This section begins with an overview of the project findings in terms of both the operation impact and component impact of extending the BOP pressure testing interval. This is followed by recommendations associated with the time-based BOP pressure testing interval, including an assessment of potential new requirements.

5.1 Project Findings

As described in Section 1.1, the goal of the project was to evaluate both the operational impact and the component reliability of potentially extending the time-based BOP pressure testing interval for the pipe rams, VBRs, and annulars. The highlights of this study and the major findings are presented in Table 5-1.

Table 5-1: Overview of Project Findings

	Impact of an Extension of the Time-Based BOP Pressure Test Interval		
Factor	**Operational Economics**	**Operational Safety**	**Component Reliability**
Analysis Results	*downtime is necessary to prepare for and perform BOP pressure tests, which adds to the costs associated with offshore drilling.* *An economic analysis found average industry wide cost savings over the next ten years of:* • *$410 Mil/year for 21 day* • *$600 Mil/year for 28 day*	*BOP pressure testing requires significant downhole and on rig operations and system reconfigurations.* *Reduction in risks associated with the following factors:* • *Downhole operations* • *High pressure rig operations* • *Potential for system misalignment*	*The BOP pressure tests is primarily a proof test of the following components:* • *BOP wellbore sealing elastomers* • *Choke/kill lines and valves* *A qualitative and quantitative reliability analysis demonstrates that there is minimal net impact on component reliability due to an extension of the time based pressure test interval.*
Conclusion	**Significant Benefit**	**Significant Benefit**	**Minimal Impact**

Section 3 examined the potential operational impact of extending the time-based pressure testing interval, in terms of both safety and economics, and the findings of the study can be found in Table 5-2. The decreased frequency of BOP pressure testing results in the potential reduction of risk factors associated with pulling the drill string off the hole bottom, lessened exposure of the rig and personnel to high-pressure operations, and the reduced probability of choke/kill line valve misalignment. As for economic impact, an extension to a 21-day time-based pressure testing interval would likely yield an industry-wide cost savings of over $400 million per year (averaged over the next 10 years), although there is significant uncertainty regarding the exact value due to difficulties with projections in this time frame.

Table 5-2: Operational Impact – Major Findings

Operational Safety	• *An extension of the time-base BOP pressure test interval could result in a decrease of several risk factors for both personnel and operational safety, including:* ○ *Reduction in the number of instances a drill string must be pulled off bottom* ○ *Reduced exposure of rig and crew to high pressure operations* ○ *Reduced potential for choke/kill system misalignment*
Operational Economics	• *An extension of the time-based BOP pressure testing interval could result in the following industry-wide cost savings:* ***21-Day****: $400 Million/year* ***28-Day****: $600 Million/year*

Section 4 examined the component impact, with the major findings highlighted in Table 5-3. Through the use of success path assessment, it was determined that the vast majority of systems/components that are necessary for successful operation of the rams/annulars are proof tested through the weekly function test. Therefore, extending the pressure testing interval primarily impacts the wellbore sealing elastomers, as they are one of the few components of the success path that are not proof tested by the weekly function test.

A review of wellbore sealing elastomer failures found that failures, in general, are rare, and the majority of failures were identified through the stump/installation pressure test or a pressure test after a potentially damaging/degradation event or condition while on the wellhead. The time-based pressure test yielded the fewest identified failures despite being the most frequent pressure test performed. Utilizing this information, a detailed reliability assessment of multiple scenarios found that extending the time-based pressure testing interval has, in general, a minimal impact on wellbore sealing elastomer reliability. The primary reason for this finding the dominant failure mechanisms of the wellbore sealing elastomers are not time-dependent phenomena. Therefore, a time-dependent test has less influence on reliability than other pressure tests that are performed, such as the stump/installation pressure test or those conducted after degrading events.

Several insights were gained regarding how wellbore sealing elastomer reliability could be improved. These actions include the use of properly qualified components and quality controls (handling/installation procedures), improved knowledge regarding potentially degrading events and conditions, and greater clarity regarding the monitoring of wellbore conditions for the identification of degrading events during operation.

Lastly, the potential impact of changes in the BOP time-based pressure testing interval on choke/kill valves and BOP bolt reliability was examined. For choke/kill valves, the high reliability of these components in conjunction with their directly redundant design results in minor changes in system failure probability. For BOP bolts, as the items of the API BOP bolting action plan are instituted, the use of the BOP pressure test as an interim action for the identification of BOP bolt failures should be reduced.

Table 5-3: Component Impact – Major Findings

Success Path Analysis	• *The main components of the success path impacted by an extension of the time-based BOP pressure testing interval are the wellbore sealing elastomers, as they are not proof tested by the weekly function test.*
Qualitative Elastomer Analysis	• *A review of non-shear ram & annular elastomer failures found that failures are rare events and the majority of failures are identified during stump and installation pressure tests or pressure tests after certain operations or are associated with degrading events while on the wellhead. The time-based pressure test, although by far the most frequent pressure test, revealed the fewest failures.*
Quantitative Elastomer Analysis	• *A detailed reliability analysis of the wellbore sealing elastomers was conducted for three scenarios:* *1) For an elastomer defect or damage during handling/installation, prevention is the key action followed by screening through the stump and installation pressure tests.* *2) For degrading events while in service on the wellhead, knowledge and avoidance is key, followed by identification of the event and an immediate pressure test.* *3) For operation without a degrading event, extension of the time-based pressure testing interval increases uncertainty regarding the status of the component, but this is generally compensated by a reduction in cumulative fatigue damage.* • *In general, time-based proof tests provide the most benefit in identifying failures caused by time-dependent phenomena. However, the dominant elastomer failure mechanisms are not time-dependent but occur as discrete events.* • *The results of the scenario analysis indicate several ways in which elastomer reliability could be improved:* o *Improvement in elastomer life-cycle quality controls and further adoption of quantifiable manufacturer minimum testing criteria.* o *Improved knowledge and guidance regarding wellbore events and conditions that can result in elastomer damage or degradation.*
Other Impacted Components	• *The high reliability of the choke/kill valves, coupled with the direct redundancy in the system design required by both regulation and standards, results in a low probability failure pathway. Therefore, an extension of the pressure testing interval for the choke/kill valves would likely have minimal impact on system reliability* • *While the BOP pressure test has been identified as an interim action to verify bolting integrity during the implementation period of the API bolting action plan, due to the nature of BOP bolts and the infrequency of their failures, the optimal pathway to improve reliability is not through increased proof-testing of in-service bolts, but through proper and rigorous qualification.*

In addition to these findings, several areas of high uncertainty were identified during the study, shown in Table 5-4. The first area relates to uncertainty regarding BOP component reliability. This is due to two factors, first being the difficulty associated with extracting information from the WARs and second, the general industry practice to not openly share component reliability information. The next two areas of uncertainty are associated with wellbore sealing elastomer failure, including degradation events and fatigue. The avoidance and identification of degradation events typically relies on driller expertise rather than definitive guidance. Data regarding the expected fatigue lifetime of elastomers is occasionally recorded by companies for internal use, but a comprehensive database of industry experience is not available. In addition, there are no current quantitative requirements regarding elastomer fatigue lifetime, although this may change if the 4th edition of API Spec 16A is incorporated by reference into regulation in the future.

Table 5-4: Identified Uncertainties

Uncertainty	*Description*
Component Reliability Data	*BOP component reliability data is difficult to extract from the Well Activity Reports (WAR) and not routinely shared within industry.*
Elastomer Degradation Events	*Guidance on the avoidance and identification of wellbore events or conditions that can potentially degrade BOP wellbore sealing elastomers is not well defined.*
Elastomer Fatigue	*Current regulation and referenced standards do not have quantitative requirements regarding BOP wellbore sealing elastomer fatigue and data sharing within industry regarding elastomer fatigue is rare.*

5.2 Addressing Uncertainties to Ensure BOP Reliability

The findings of the current study indicate that an extension of the time-based pressure testing interval for annulars, pipe rams, and VBRs has minimal impact on elastomer reliability, while increasing operational safety and providing significant cost savings for industry. However, as described in the preceding section, three major areas of uncertainty regarding elastomer reliability were identified through the course of the project. To ensure high BOP reliability in the event of an extension of the BOP pressure testing interval beyond 14-days or a transition to a performance-based or risk-informed test protocol (discussed in Section 5.3), a series of potential actions were explored to address the areas of uncertainty. These actions have been categorized by type, as shown in Table 5-5. The following subsections detail each of these action categories, including a description of how they reduce uncertainty and an estimate of their cost to industry.

Table 5-5: Potential Actions to Address Uncertainties

Topic	*Potential Actions to Address Uncertainties*
WAR Data Actions	*Modifications to the Well Activity Report format and database structure to improve reporting consistency and aid in future data mining efforts.*
Equipment Qualification Actions	*Uncertainty regarding elastomer fatigue could be addressed through the adoption of the PR2 level of the 4th edition of API 16A, which has quantitative minimum elastomer performance requirements.*
Condition-Based Actions	*Multiple uncertainties could be addressed through the establishment of an allowable elastomer operating window for each well and the tracking of elastomer cycles, operations, and exposed conditions during time in service.*
Performance-Based Actions	*Multiple uncertainties could be addressed through the use of elastomer performance trend analysis utilizing digital pressure testing and post use elastomer inspection.*

5.2.1 WAR Data Actions

As described in Section 4.2.3, an effort was made to review post-Macondo failures of BOP wellbore sealing elastomers. This was done primarily through an examination of 2011-2017 WAR data. However, due to the quality of the data provided in the WARs within the TIMS database, it could not be confidently asserted that all failures during this time period were identified. This fact was generally a result of the inconsistencies in the data reporting process, which made the data-mining process extremely difficult. This was due to several factors:

- Not all failures of BOP wellbore sealing elastomers were properly identified as "Significant Well Events – Well Control Equipment Failure."
- For BOP pressure tests, the specific reason for the pressure test is rarely stated and must be deduced from the collection of WAR reports for a well.
- Inconsistent terminology was utilized to describe failures (*e.g.*, "failed to test", "did not test", "did not seal", "leak present", "failed to hold pressure", etc.).
- Very little information is typically provided regarding BOP wellbore sealing failures, such as the specific component that was found to have failed.

Taken together, these factors make any automated data search process nearly impossible. Instead, experienced offshore personnel are needed to individually review suspect WARs for failure information. This process is not conducive to extracting important insights from such a large database and similar issues have been encountered in past studies (see Section 16.5 of ref [26]).

Moving forward, consideration should be given to ways in which the WAR reporting format and structure could be modified, such as those outlined in Table 5-6, to improve consistency and ease the use of searching algorithms. The first recommendation is in regard to clarifying the specific definition of the "significant event – well control equipment failure" flag. The second recommendation encourages the listing of the reason for testing (such as installation, time-based, after event, etc.). Next, there is an opportunity to provide guidance to industry on the terminology for the description of BOP failures, whether encountered through testing or operations. The last recommendation is to encourage industry to list a preliminary failure mode for well control equipment failures. As time or information may be limited, a gross analysis of the cause of failure, such as a control system issues versus a wellbore sealing elastomer issue, would be appropriate.

Table 5-6: Potential WAR Data Improvements

Description
• *Clarify the WAR definition of a "Significant Event – Well Control Equipment Failure" to include any failure of a BOP wellbore sealing elastomer during testing or operations.*
• *For WARs that include a BOP pressure test, encourage the documenting of the reason for the pressure test[1].*
• *Provide guidelines on the use of consistent terminology regarding BOP failures, whether encountered during testing or operations.*
• *For BOP failures, encourage the documenting of a gross analysis of the cause of failure, such as a control system or elastomer failure.*

[1] There may be multiple purposes for a BOP pressure test.

5.2.2 Equipment Qualification Actions

One area of uncertainty identified by the current analysis relates to the accumulation of elastomer fatigue damage and the subsequent impact on the probability of elastomer failure. Data regarding this phenomenon is not readily available, however, this factor has a large impact on the results of the elastomer reliability analysis discussed in Section 4.2.4 and Appendix E. Therefore, potential equipment qualification actions, highlighted in Figure 5-1 and described in Table 5-7, were developed, with separate potential requirements for wellbore sealing elastomers and BOP bolts. As described in Section 4.2.1, the 4th version of API 16A now contains two performance requirement levels with separate minimum acceptance criteria. The enhanced qualification testing associated with level PR2 includes many quantifiable minimum criteria, which were only "reportable" in previous standard versions and for PR1. There are several reasons why the use of PR2-qualified pipe rams, VBRs, and annulars (or demonstrated equivalence based on past operating performance[30]) c an help improve confidence in BOP performance in the presence of reduced pressure tests.

[30] The exact process to determine equivocal performance of non-PR2 qualified equipment would require additional research and coordination with API 16A.

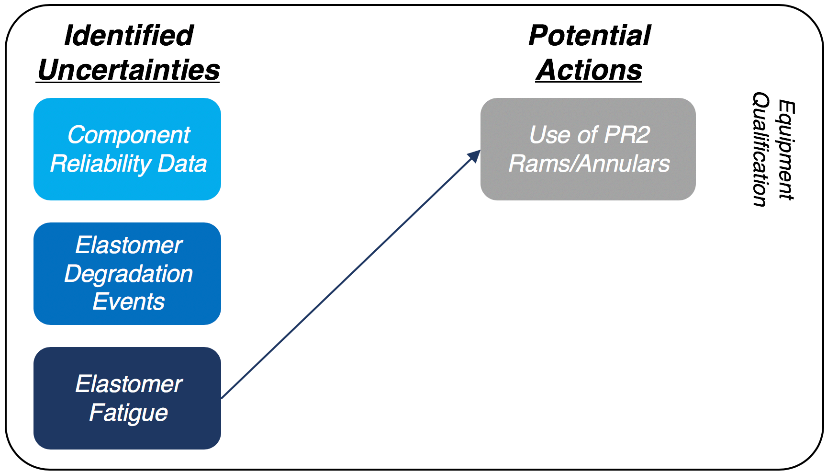

Figure 5-1: Connection Between Identified Uncertainties and Equipment Qualification Actions

First, the clear definition of minimum acceptance criteria for critical ram/annular characteristics, such as fatigue life, stripping, and performance in high/low temperatures, provides valuable guidance to industry regarding component lifespans and acceptable operating windows. This information is vital in determining replacement timelines and the identification of potentially damaging/degrading events. This factor also sets minimums for cumulative fatigue damage, an important factor in the elastomer reliability analysis performed here and a main point of uncertainty. The PR2 requirements align with the assumptions utilized in the reliability model of the current study for cumulative fatigue damage. The adoption of this requirement level would provide additional confidence in the reliability model results and findings. In addition, PR2 requires more detailed operating manual information regarding elastomer test performance. This information can assist in the reduction of elastomer failures from both of the dominant failure mechanism categories (material defect/improper handling and installation and damaging/degrading events and conditions).

The second potential equipment qualification action is associated with BOP bolts. As described in Section 4.3.2, in response to a series of bolt failures, industry and API developed a proposed action plan to increase bolt reliability. This included actions such as the adoption of API 20 E/F for critical BOP bolting and upgrading of critical bolting with hardness >35 HRC. If implemented, the steps in the action plan help ensure confidence in the BOP bolts and reduce the need of the BOP pressure test as a mechanism for the identification of BOP bolting failures.

Table 5-7: Potential Equipment Qualification Actions

Action	***Description***
Use of pipe rams, VBRs, and annulars that satisfy performance requirement level two (PR2) of API Spec 16A, 4th Edition (or demonstrate equivalence through historical data)	*Level PR2 includes more stringent minimum acceptance criteria regarding elastomer manufacturer validation testing and more detailed operating manual information. However, since PR2 is a new qualification requirement, historical operating data could be utilized to demonstrate equivalent performance.*
Implement steps defined in March 31st, 2016 API bolting action plan	*The steps outlined in the action plan, such as the use of API 20 E/F for critical BOP bolting, help ensure BOP bolt reliability and reduce the need for the BOP pressure test as a bolting failure identification pathway.*

5.2.3 Condition-Based Actions

Equipment qualification is one avenue to address uncertainty regarding elastomer fatigue, another potential path are condition-based actions, which account for the conditions and operations that the elastomers encounter during their time-in-service. Such actions could help reduce the uncertainty related not only to elastomer fatigue, but other factors. First, there is uncertainty related to the collection of component reliability data and the difficulties associated with the extraction of reliability data from the currently available database. Another area of uncertainty is associated with the wellbore events and conditions that may damage or degrade the elastomers. Specifically, industry guidance regarding when to conduct a pressure test after these events is not as well defined as the standard and regulatory requirements related to other pressure tests. To address these factors, a series of condition-based actions were developed, as outlined in Figure 5-2.

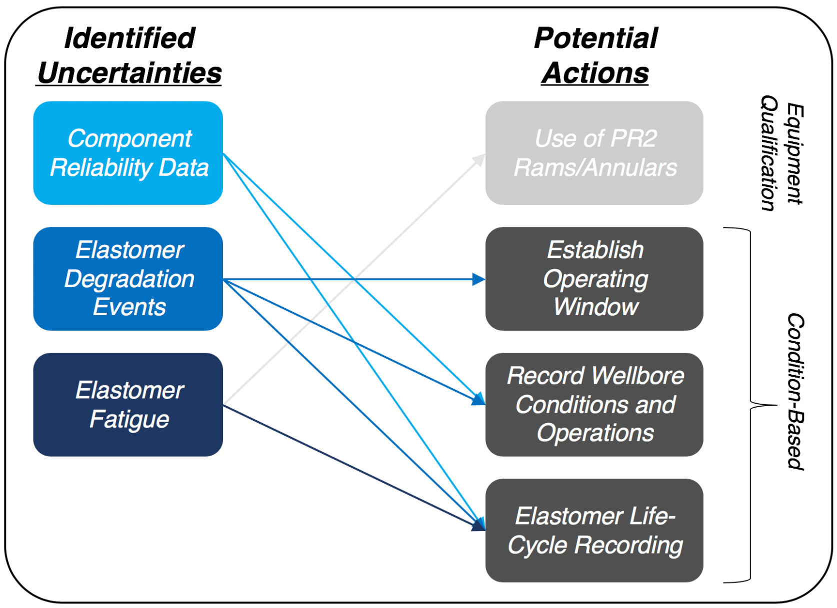

Figure 5-2: Connection Between Identified Uncertainties and Condition-Based Actions

The potential condition-based actions are detailed in Table 5-8, which focus on ensuring proper elastomer usage and the collection of reliability data. This begins with the creation of an elastomer "operating window" document for each well, which describes planned well conditions (fluids, temperatures, pressures) and expected operations (stripping, hangoffs, fatigue cycles, etc.). This document sets the design requirements for the BOP wellbore sealing elastomers and would build off API 53 requirements [10], such as 6.5.4.10 and 6.5.4.11, which require verification of elastomer compatibility and characteristics. Next, during well operations, the wellbore conditions, operations, and BOP use cycles are recorded and compared to the elastomer operating window. This ensures that the operating window is not exceeded and the elastomers are not exposed to conditions or events that may compromise their performance.

Although the actions related to the elastomer "operating window" are mainly quality control documents and book-keeping, they are important for formalizing the process to assure elastomer reliability. In addition, with each completed well, the knowledge database regarding elastomer performance will expand and be complemented with recorded, citable operating records. These actions not only help expand the knowledgebase regarding elastomer fatigue damage (another area of uncertainty), but also aid in the definition of, and guidance associated with, wellbore events or conditions that may damage or degrade wellbore sealing elastomers.

The information collected by the condition-based actions could aid in the future development of an industry-wide component reliability database. Although not currently in place, the creation of such a system could be warranted due to the important role of the wellbore sealing elastomers for well control. At the very least, the improvement of internal company record-keeping could help shift knowledge from driller experience to defined requirements, such as improving the guidance on when to pressure test after potentially degrading operations. Real-world data collection is also vital for addressing areas that are not covered by elastomer testing in API 16A, such as long-term elastomer compatibility with well fluids. As will be described later, this additional data collection and reliability analysis could provide a basis for or potentially transitioning the pressure testing requirement from time-based to performance-based criteria.

Table 5-8: Potential Condition-Based Actions

Action	***Description***
Establish and Document Operating Window	*Create a document outlining the expected wellbore conditions and wellbore operations to be encountered. Information could include the wellbore fluids to be utilized, expected wellbore temperatures and pressures, wellbore operations (hangoff/stripping limits), etc. Include information regarding the expected number of use cycles. Verify BOP wellbore sealing elastomers are suitable for operating window. Document actions if operational window is exceeded (early pressure test, switch use of ram, etc.)*
Wellbore Condition and Operations Recording	*During operation, document the wellbore conditions and operations and verify they are within the operating window.*
Elastomer Life-Cycle Recording	*During operation, document the use cycles (open/close and pressure cycles) of the BOP ram and annular elements and verify they are within the operating window.*

5.2.4 Performance-Based Actions

The analyses described in Sections 3 and 4 demonstrated that a transition to a 28-day time-based pressure testing interval for the annulars, pipe rams, and VBRs provides a significant economic benefit with minimal impact on elastomer reliability. However, such a testing protocol would represent a substantial change in testing requirements, and additional actions may be warranted to ensure that the well operations are not continuing for multiple days with a failed elastomer. Therefore, a category of performance-based actions is provided that assess elastomer performance throughout the well to prevent the operation of the BOP with a degraded or failed elastomer. The performance-based actions provide additional protections against all three identified uncertainties, as shown in Figure 5-3.

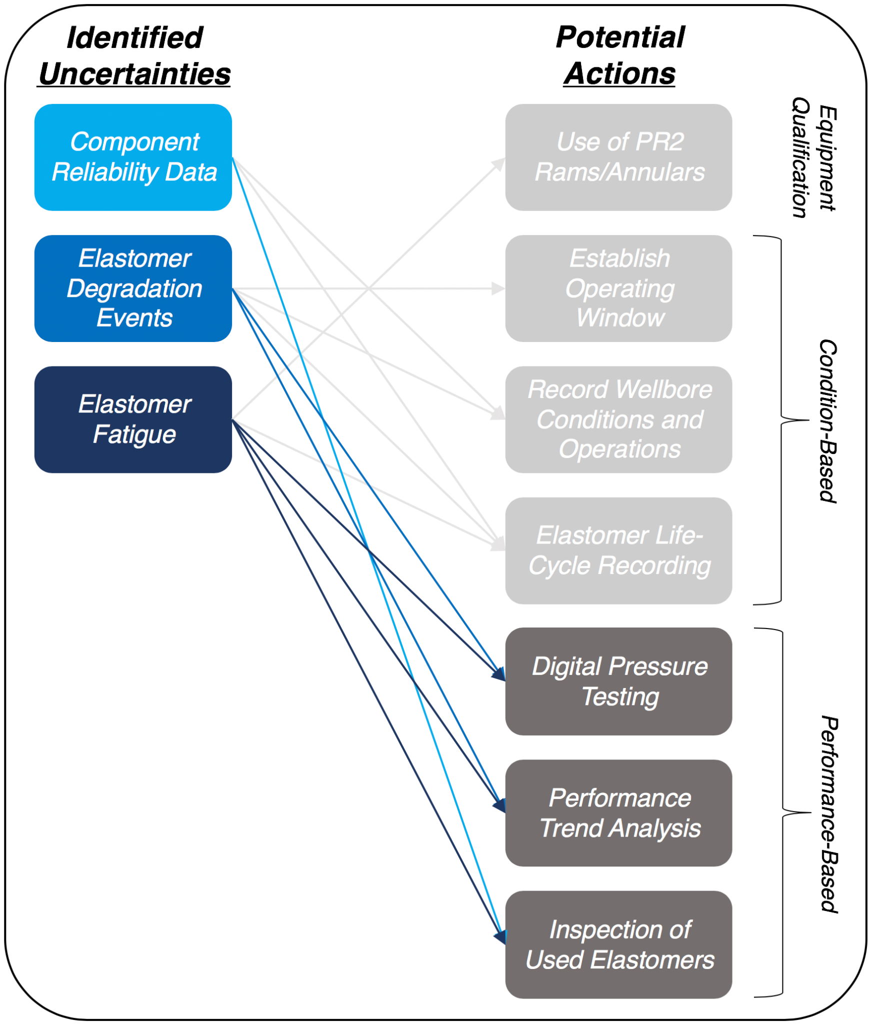

Figure 5-3: Connection Between Identified Uncertainties and Performance-Based Actions

In addition to the equipment qualification (Table 5-7) and condition-based (Table 5-8) actions of the previous two sections, Table 5-9 outlines a series of performance-based actions intended to improve elastomer reliability and address the major sources of uncertainty. The first action is the use of digital pressure testing, or in other words, the use of pressure testing techniques that allow the digital archiving of pressure test performance data[31]. Digital pressure testing can use the same pressure transducer equipment as CCR testing, but simply includes recording the output data in a digital format. Collecting pressure test performance data in this manner permits the second potential action, which is the monitoring and assessment of elastomer pressure test performance over the elastomer lifetime. Such an analysis could include comparing the response (leak-off rate) of the BOP element from one test to the next in an effort to identify changes in elastomer performance. The goal is to recognize potential degradation or damage before it becomes of sufficient severity to impact well control operations. In addition, digital pressure testing is typically used in conjunction with test planning tools, which can aid in the avoidance of system misconfigurations, a risk factor identified in Section 3.1.3. These steps, in conjunction with the

[31] If such an action is instituted, it is important to include operational options if digital pressure testing equipment becomes non-operational, such as permitting the use of CCR techniques and a reduced time-based pressure testing interval in the interim.

condition-based actions in Table 5-8, also help provide the information necessary for industry to transition to a maintenance and inspection program that is based on equipment use cycles, the conditions/events encountered, and diagnostic data, rather than set time intervals.

The final performance-based action is associated with used elastomer analysis. While BOP repairs or maintenance are being performed, some portion of the wellbore sealing elastomer population that is removed from the BOP should be saved and subjected to further inspection and forensic analysis. The goal of this action is to continue to improve the knowledge base regarding elastomer performance in various well operations and conditions. The results of this action could provide assurance that an extension of the time-based pressure testing interval is not impacting elastomer wear patterns or degradation and could help identify unknown types of damaging events. This analysis, in conjunction with the life-cycle documentation action in Table 5-8 provides a comprehensive elastomer performance database and could help provide the basis for a future performance-based BOP pressure testing protocol. The PR2 level of the 4th edition of API 16A potentially lays the groundwork for such a requirement, as it mandates inspection protocol (including non-destructive evaluation, dimensional inspection, etc.) within the BOP element operating manual[32].

Table 5-9: Potential Performance-Based Actions

Action	*Description*
Digital Pressure Testing	*Utilize digital pressure testing techniques that allow the recording and archiving of pressure test performance data.*
Performance Trend Analysis	*Analyze pressure testing performance data of individual BOP rams/annulars over their lifetime with the focus on identifying degradation in performance.*
Inspection/Analysis of Used Elastomers	*After removal from the BOP, subject some portion of wellbore sealing elastomer population to additional inspection and forensic analysis. Utilize life-cycle documentation to establish wear patterns and potential degrading events/conditions.*

5.2.5 Cost-Benefit Analysis of Potential Actions

Since the potential actions outlined in Sections 5.2.2 through 5.2.4 could result in additional costs for operators, a cost-benefit analysis was performed to determine the net impact on operational costs. This analysis utilizes the same economic model described in Section 3.2 and Appendix A.

For this analysis, cost estimates were established for each of the actions listed in Table 5-7 through Table 5-9. There is significant uncertainty regarding the estimates due to several factors. First, some of the potential new actions are partly covered in existing requirements, but in different ways. For example, the condition-based action for documentation of wellbore conditions and operations is related to CFR 250.703(c), which requires constant well surveillance, unless secured. In addition, some operators have already begun to institute several of the potential actions, such as digital pressure testing or documenting elastomer life-cycles.

The cost estimates are provided in Table 5-10. For each action, a mean value cost was estimated and a low/high estimate. Some of the requirements are a single cost per well, while others are a

32 See 4.9.i of ref [17].

monthly operating cost. There is large uncertainty associated with the estimates, as the details regarding their implementation would have a great impact on the cost. Discussions and records from industry, including operators, contractors, and BOP manufacturers, were used as the basis for the estimates.

Table 5-10: Potential Actions – Cost Estimates

Action	Cost Estimate				
	Low	Mean	High	Units	Frequency
Use of PR2 Rams/Annulars[1]	$5,000	$25,000	$50,000	5/BOP	Per Well
API Bolting Action Plan[2]	-	-	-	-	-
Document Operating Window	16hr	24hr	40hr	$200/hr	Monthly
Wellbore Recording	50hr	100hr	200hr	$200/hr	Monthly
Life-Cycle Recording	20hr	40hr	80hr	$200/hr	Monthly
Digital Pressure Testing[3]	75%	50%	25%	$50,000	Per Well
Performance Trend Analysis	20hr	40hr	80hr	$200/hr	Monthly
Analysis of Used Elastomers	$10,000	$15,000	$20,000	1	Per Well

[1] Assuming a total of five annulars, pipe rams, and VBRs per BOP stack. Cost in addition to typical elastomer cost.
[2] Assumed to occur regardless of potential changes to BOP pressure testing interval.
[3] Percentage of wells not already using digital pressure testing.

Utilizing these costs, an industry-wide cost per year was calculated for both the 21-day and 28-day requirements. It was assumed that the equipment qualification and condition-based actions were utilized for a 21-day pressure testing interval, while the equipment qualification, condition-based, and performance-based actions were used for a 28-day interval. The results of this analysis can be found in Table 5-11, which gives the average cost per year for all of industry. Using the results of the cost-savings analysis in Section 3.2, a net benefit was calculated, as shown in Table 5-11 and Figure 5-4. As the results demonstrate, when including the costs of the equipment qualification and condition-based actions, there is a mean reduction in the net benefit of only 7.4%. When exploring a 28-day testing protocol and the actions from all three categories, there is a reduction in cost savings of 6.3%. Of all the potential actions, the most costly may be the use of PR2-qualified annulars and rams. This value is particularly difficult to estimate, as the 4th edition of API Spec 16A was recently released ,and cost estimates for PR2 qualified equipment are still uncertain. It is possible that the estimates utilized here may be higher than the final additional cost for qualification.

Table 5-11 Potential Actions Cost – Key Results

Input Values	Industry-Wide per Year[1]					
	21-Day[2]			28-Day[3]		
	Cost ($Millions)	Reduction of Cost Savings (%)	Net Cost Savings ($Millions)	Cost ($Millions)	Reduction of Cost Savings (%)	Net Cost Savings ($Millions)
Low	$13.65	3.31%	$399.35	$17.22	2.89%	$578.68
Mean	$30.60	7.41%	$382.40	$37.74	6.33%	$558.16
High	$60.07	14.54%	$352.93	$73.61	12.35%	$522.29

[1] Averaged over next 10 years.
[2] Comparison of 18-day versus 11-day.
[3] Comparison of 25-day versus 11-day.

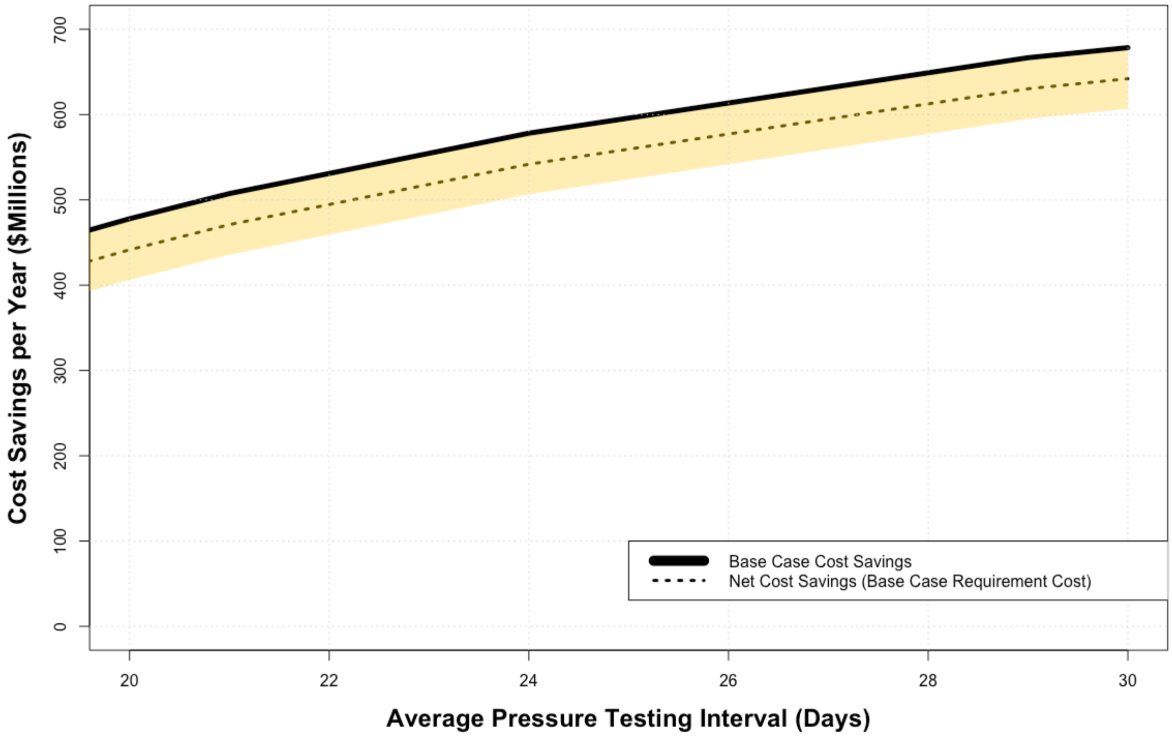

Figure 5-4: Cost-Benefit Analysis Results with All Potential Actions

5.3 Project Recommendations

As described by the project findings in Section 5.1, due to the nature of the dominant failure mechanisms of the wellbore sealing elastomers, there is a potential opportunity to transition from a time-based BOP pressure testing interval to one that is performance-based or risk-informed. For example, a performance-based approach might utilize information regarding ram/annular pressure testing results in conjunction with fatigue and wellbore operations information to determine the need for pressure testing. A risk-informed approach might include similar information, but also account for the role of the specific ram/annular in well control activities and the risk associated with the specific well and current operations.

Project Recommendation

A transition from a time-based BOP pressure testing program to a performance-based or risk-informed program may be possible but is dependent on increased component reliability data collection and improved industry guidance regarding the occurrence of potentially degrading events.

Based on the current study, there are several issues that must first be addressed before such a program could be instituted. First, historically, the manufacturing qualification standards for the wellbore sealing elastomers (outlined in API 16A) have not contained quantifiable minimum requirements regarding elastomer performance. Although this has now changed with the introduction of the PR2 level in the 4th edition of API 16A, this is a recent development and will take some period of time before industry adoption. Second, the guidance regarding when a pressure test should be performed following a potentially damaging/degrading event is not as refined as other BOP testing protocols and relies mostly on industry best practices and driller knowledge. Because of this, it is possible that pressure tests may not be performed after certain degradation events. Currently, the time-based pressure test is an insurance policy against such a scenario and ensures that a pressure test will be performed within a reasonable amount of time.

A transition from the time-based pressure testing interval is possible if these areas of uncertainty are resolved. First is the industry adoption of clearer, quantifiable qualification standards for the wellbore sealing elastomers and the collection of operational reliability data. Second is continued development of a knowledge database regarding elastomer performance, including degrading events/conditions and elastomer cumulative fatigue damage. Such knowledge could be gained through additional elastomer testing, improved archiving of elastomer life cycles, and the examination of used elastomers. Many of these uncertainty factors could be addressed through the implementation of the three categories of potential actions outlined in Sections 5.2.2 through 5.2.4.

In addition, a pilot program using a 21-day (or similar extended period) time-based BOP pressure testing interval could play an important role in providing validation data and supporting the findings of the current study. However, it is difficult to rely solely on the results of a pilot program for the justification of future pressure testing modifications due to the infrequency of wellbore sealing elastomer failure. Since failure is rare, the pilot period necessary to provide statistically meaningful results could be prohibitively long. For example, based on the results in Appendix E, the standby failure rate of an annular (failure being a wellbore sealing elastomer failure) is estimated to be ~9.8E-5 per day. This implies a mean time to failure (MTTF) of

~10,200 standby days. Assuming each BOP has two annulars, this gives a MTTF of ~5,000 BOP operating days. If it is assumed that an average well takes 120 BOP-days, it would take over 40 wells to reach 5,000 BOP days. Since failures are rare, a significant amount of 21-day data is necessary to provide confidence in a direct 14-day to 21-day comparison. In addition, if an elastomer failure were to occur early in a pilot program, it could be misconstrued as being a direct result of the 21-day program when there are many other failure mechanisms and factors that must be considered, as described in Section 4.2.2.

Despite its limitations, the data from a 21-day pilot program could be useful in supporting and validating the analyses performed here, such as those assumptions related to elastomer fatigue and the rare occurrence of standby failures. In addition, it could begin the process of addressing the uncertainties outlined in Section 5.1 by increasing the elastomer reliability database and providing new information regarding elastomer degradation. However, for such improvements to occur, actions are needed to collect and document such reliability information during the pilot period.

6 References

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Appendix A: Economic Model

A.1 Introduction

Argonne researchers used quantitative methods to develop a structured analytical framework for estimating the cumulative 10-year costs associated with BOP pressure testing for a range of testing intervals. The economic model developed to estimate costs associated with different pressure testing intervals accounts for *economic benefits* in terms of cost reductions from reduced downtime and *additional costs* related to potential actions outlined in Sections 5.2.2 through 5.2.4 of the main report.

This Appendix describes the methodology and assumptions used to compare alternative pressure testing requirements.

A.2 Methodology for Economic Evaluation

Economic Model Assumptions

The following parameters are used in measuring benefits and costs of alternative time-based pressure testing intervals:

Study Period: The period of analysis spans from January 2019 through December 2028.

***Discount Rate*:** In measuring NPV, the CBA is performed in constant dollars and applies a real discount rate of 3%. No income taxes or royalty taxes are included in the net present value analysis, as these amounts are transfers that do not affect the inherent benefits or costs to society.

BOP Pressure Testing Interval: Time interval (days) between the time-based BOP pressure test while the BOP is on the well.

Rig Downtime per Testing Cycle: Total rig downtime (hours) for each pressure testing cycle. This includes the time necessary to prepare and perform the pressure test.

Daily Lease Cost per Rig: The total daily lease cost ($) per rig. This includes direct rig costs and also associated contractors and vessels.

Number of Rigs in Operation: The total number of rigs in operation in the GoM in a given year.

Rig Utilization Factor: Percentage of time in a year that a rig is operating with a BOP on the well and therefore subject to the time-based BOP pressure test requirement.

Cost of Potential Qualification Actions: The cost estimates, provided in Table 5-10, for potential actions required to qualify for an extended pressure testing interval. Depending on the qualifying action, values can be specified as a single capital cost per rig or a monthly operating cost.

Illustrative assumptions for the economic model are displayed in Figure A - 1.

Key Assumptions for Single Run

	Unit	Value
BOP Pressure Testing Interval	days	11
Rig Downtime per Testing Cycle	hours	24
Daily Lease Cost per Rig	nominal USD	1,000,000
Real Discount Rate		3.00%

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Number of Rigs in Operation	59	59	59	59	59	59	59	59	59	59	59
Rig Utilization Factor	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%

Estimated Cost of Potential Qualification Actions

Action	Cost per Unit	Unit	Units per Rig	Timing	Total - One Time	Total - Monthly	Percent of Existing Rigs Applicable	Percent of New Rigs Applicable
Potential Elastomer Testing Requirements								
Use of PR2 rams/annulars	$25,000	per ram	50	One-time	$1,250,000		100%	100%
Potential Condition-Based Testing Requirements								
Establish/document operating window	$200	per hr	24	Monthly		$4,800	100%	100%
Monitor wellbore conditions/operations	$200	per hr	100	Monthly		$20,000	100%	100%
Potential Performance-Based Testing Requirements								
Digital pressure testing	$50,000	per well	1	One-time	$50,000		50%	100%
Performance trend analysis	$200	per hr	40	Monthly		$8,000	100%	100%
Life-cycle recording	$200	per hr	40	Monthly		$8,000	100%	100%
Inspection/analysis of used seals	$5,000	per ram	1	Monthly		$5,000	100%	100%

Figure A - 1: Illustrative Assumptions and Input Data for the Economic Model

A.3 Economic Model Computations

The economic model enables efficient evaluation of alternative testing intervals.

Representative Pressure Testing Schedule

Based on input data specified in Figure A - 1, the model calculates a representative daily schedule of rig operations over the study period. As displayed in row 61 of Figure A - 2, the amount of time between pressure tests (447.46 hours) is computed as the BOP Pressure Testing Interval (11 days) divided by the Rig Utilization Factor (59%) times 24 hours in a day.

The remaining hours before a required pressure test is tracked in row 66 of Figure A - 2, and number of hours of rig downtime for pressure each day is displayed in row 92. Conditional formatting is used to highlight periods of rig downtime for pressure testing in the color blue.

Cost Analysis

Next, the economic model computes the estimate costs associated with rig downtime for pressure testing and potential qualification actions. The total cost associated with rig downtime for required pressure testing (row 113) is computed as the Cost of Rig Lease per Day ($1 million) times the Percent of Day Out for pressure testing (row 98) times the number of rigs in operation (59).

				1	2	3	4	5	6	7	8	9	10
1	**Timeline**												
2	Period Number			1	2	3	4	5	6	7	8	9	10
3	Start of Period			1-Jan-19	2-Jan-19	3-Jan-19	4-Jan-19	5-Jan-19	6-Jan-19	7-Jan-19	8-Jan-19	9-Jan-19	10-Jan-19
6													
54	**Representative Schedule of Rig Operations**												
59	Percent of Time in Operation			59.00%	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%
60	Adjusted Testing Interval Days for Operation Percent			18.64	18.64	18.64	18.64	18.64	18.64	18.64	18.64	18.64	18.64
61	Testing Interval Hours (Days x 24)			447.46	447.46	447.46	447.46	447.46	447.46	447.46	447.46	447.46	447.46
62													
66	Remaining Hours before Pressure Test			447.46	423.46	399.46	375.46	351.46	327.46	303.46	279.46	255.46	231.46
91													
92	Pressure Testing Hours in Period	Hrs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
94													
95	**Rig Downtime Cost Analysis**												
96	Per Rig												
97	Cost of Rig Lease per Day	USD		1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
98	Percent of Day Out	%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
99	Lease Cost Amount	USD		-	-	-	-	-	-	-	-	-	-
106													
108	Number of Rigs	Number	59	59	59	59	59	59	59	59	59	59	59
110	Aggregate												
111	Total Downtime for Pressure Testing	Hrs		0	0	0	0	0	0	0	0	0	0
113	Aggregate Lease Cost During Testing	USD		-	-	-	-	-	-	-	-	-	-
118													
119	**Cost of Qualification Actions**	**Interval**											
127	One-time Up-front Capital Cost												
130	Cost per Rig - Existing	USD	1,275,000	-	-	-	-	-	-	-	-	-	-
131	Total Up-Front Cost for All Rigs		75,225,000	-	-	-	-	-	-	-	-	-	-
132													
136	On-Going Operation & Maintenance Cost												
137	Cost per Rig per Day	USD/Day		1,504.72	1,504.72	1,504.72	1,504.72	1,504.72	1,504.72	1,504.72	1,504.72	1,504.72	1,504.72
138	Percent Applicable	%		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
139	Total On-Going Cost - All Rigs			88,779	88,779	88,779	88,779	88,779	88,779	88,779	88,779	88,779	88,779

		11	12	13	14	15	16	17	18	19	20	21
1	**Timeline**											
2	Period Number	11	12	13	14	15	16	17	18	19	20	21
3	Start of Period	11-Jan-19	12-Jan-19	13-Jan-19	14-Jan-19	15-Jan-19	16-Jan-19	17-Jan-19	18-Jan-19	19-Jan-19	20-Jan-19	21-Jan-19
6												
54	**Representative Schedule of Rig Operations**											
59	Percent of Time in Operation	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%	59.00%
60	Adjusted Testing Interval Days for Operation Percent	18.64	18.64	18.64	18.64	18.64	18.64	18.64	18.64	18.64	18.64	18.64
61	Testing Interval Hours (Days x 24)	447.46	447.46	447.46	447.46	447.46	447.46	447.46	447.46	447.46	447.46	447.46
62												
66	Remaining Hours before Pressure Test	207.46	183.46	159.46	135.46	111.46	87.46	63.46	39.46	15.46	432.00	438.92
91												
92	Pressure Testing Hours in Period	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.54	15.46	0.00
94												
95	**Rig Downtime Cost Analysis**											
96	Per Rig											
97	Cost of Rig Lease per Day	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
98	Percent of Day Out	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	35.59%	64.41%	0.00%
99	Lease Cost Amount	-	-	-	-	-	-	-	-	355,932	644,068	-
106												
108	Number of Rigs	59	59	59	59	59	59	59	59	59	59	59
110	Aggregate											
111	Total Downtime for Pressure Testing	0	0	0	0	0	0	0	0	504	912	0
113	Aggregate Lease Cost During Testing	-	-	-	-	-	-	-	-	21,000,000	38,000,000	-
118												
119	**Cost of Qualification Actions**											
127	One-time Up-front Capital Cost											
130	Cost per Rig - Existing	-	-	-	-	-	-	-	-	-	-	-
131	Total Up-Front Cost for All Rigs	-	-	-	-	-	-	-	-	-	-	-
132												
136	On-Going Operation & Maintenance Cost											
137	Cost per Rig per Day	1,504.72	1,504.72	1,504.72	1,504.72	1,504.72	1,504.72	1,504.72	1,504.72	1,504.72	1,504.72	1,504.72
138	Percent Applicable	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
139	Total On-Going Cost - All Rigs	88,779	88,779	88,779	88,779	88,779	88,779	88,779	88,779	88,779	88,779	88,779

Figure A - 2: Daily Schedule and Costs for Economic Model Run with Data in Figure A - 1

A.4 Economic Model Results

Finally, the economic model performs the cost analysis described above for pressure testing intervals ranging from 10 to 30 days and reports the associated present value (PV) and nominal system-wide costs over the 10-year period of analysis. Results of the Base Case 11-day testing interval and cost differential for alternative intervals are displayed in Table A -1.

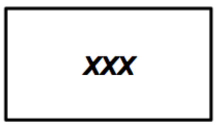
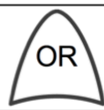
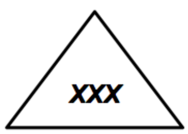
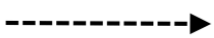
Table A - 1: Economic Model Results for Base Case

Testing Interval	PV Cost	Nominal Cost	PV Diff	Nominal Diff
10	10,365	11,977	(916)	(1,062)
11	9,449	10,915	-	-
12	8,728	10,089	721	826
13	8,067	9,322	1,382	1,593
14	7,506	8,673	1,943	2,242
15	7,043	8,142	2,406	2,773
16	6,588	7,611	2,861	3,304
17	6,228	7,198	3,221	3,717
18	5,873	6,785	3,576	4,130
19	5,595	6,468	3,854	4,447
20	5,309	6,136	4,139	4,779
21	5,055	5,841	4,394	5,074
22	4,848	5,605	4,601	5,310
23	4,643	5,369	4,806	5,546
24	4,441	5,133	5,008	5,782
25	4,285	4,956	5,164	5,959
26	4,130	4,779	5,319	6,136
27	3,977	4,602	5,471	6,313
28	3,826	4,425	5,623	6,490
29	3,676	4,248	5,773	6,667
30	3,571	4,130	5,878	6,785

Appendix B: Success Paths

This section provides the complete pipe ram success path described in Section 4.1. This begins with a review of the pipe ram success path itself and is followed by the success path for the support systems. Some of the success paths are shared from ref. [7]. More information about the success path approach to safety can be found in ref. [27]. The success path diagrams use notation similar to fault trees, seen in Table A - 2. However, the success path diagrams depict what systems, components, and actions are necessary for success, rather than noting possible failure modes.

Table A - 2: Success Path Diagram Notation

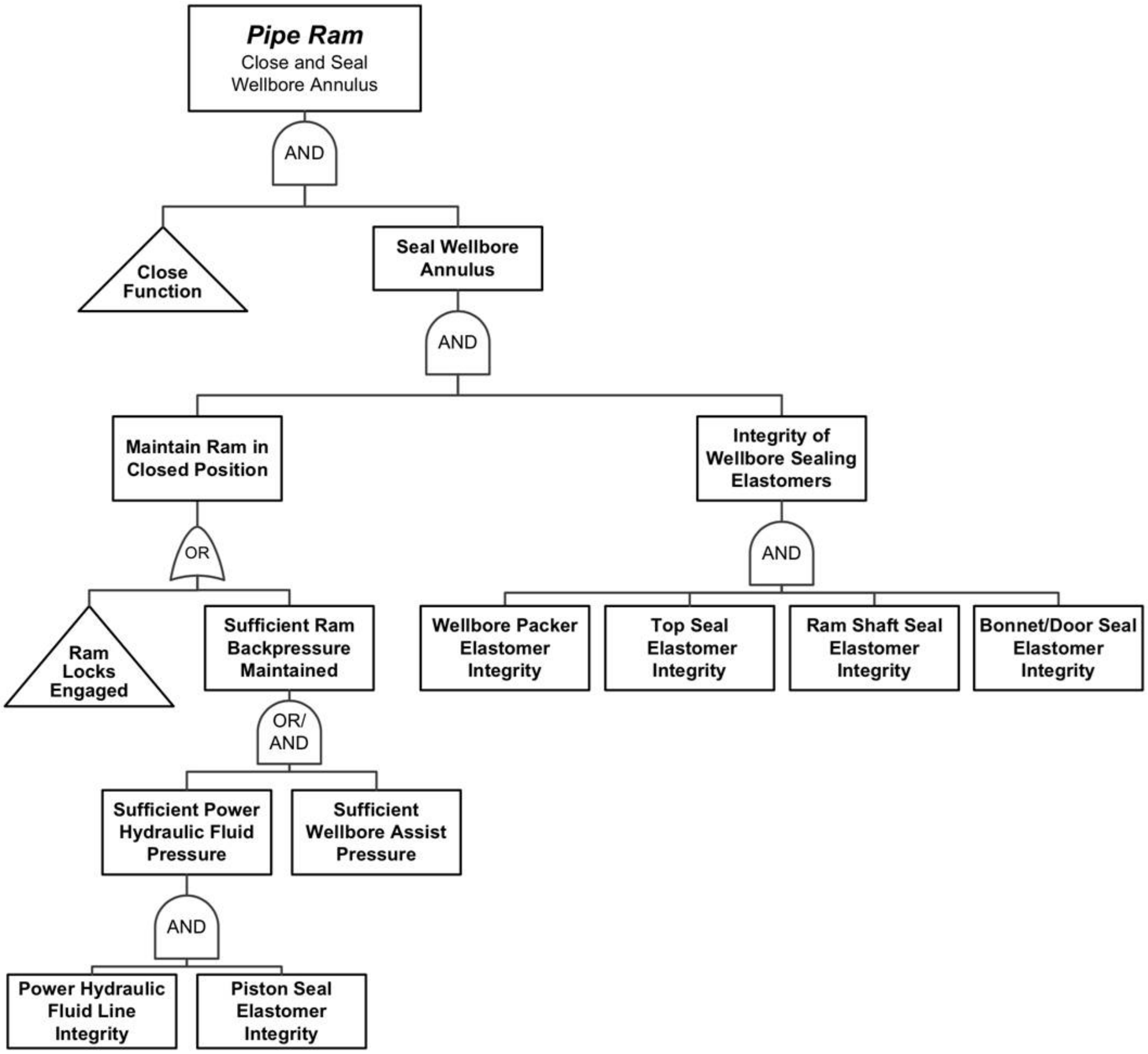
Symbol	***Name***	***Description***
	*System, Group, Function, or Base Event*	*Name of a system, group of functions, intermediate step, or base event*
	*AND - Gate*	***All** of the inputs are necessary for success*
	*OR - Gate*	***Any** of the inputs are adequate for success*
	*Transfer Gate*	*Transfer to a different success path diagram*
	*Actuation Progression*	*Shows the order of actions/ component actuation*

B.1 Success Path – Pipe Ram

Applicability

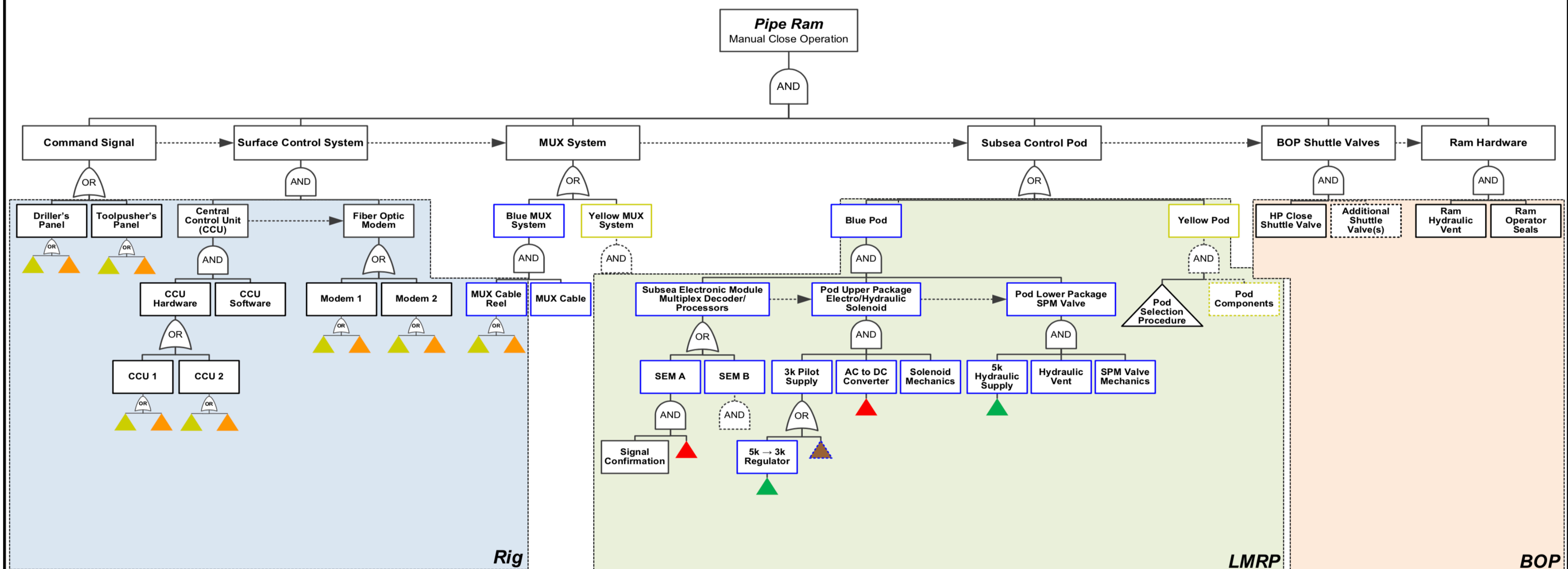
Safety Function

Success Path



Alternative Success Paths	
Necessary Support Systems	
Threat Scenarios	

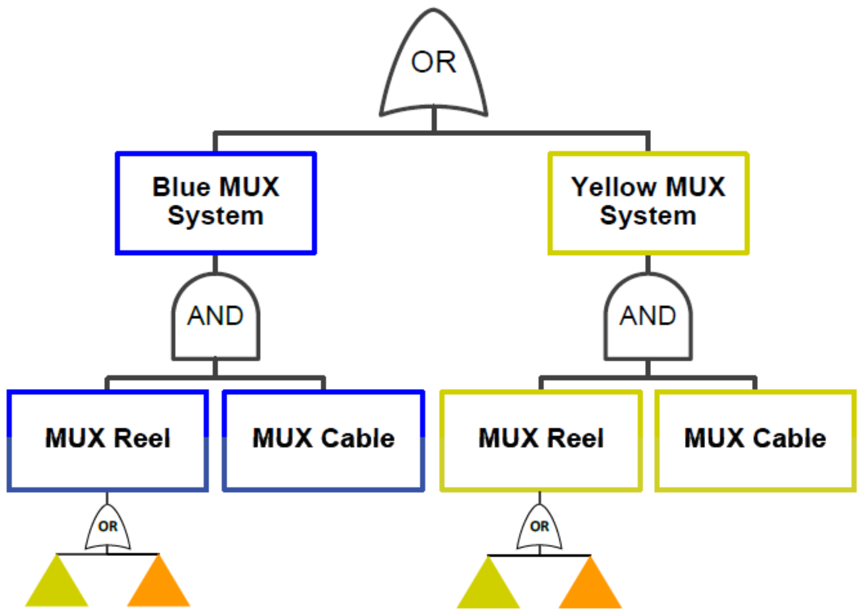
Physical Barrier: Pipe Ram

Applicability	Conventional Drilling
Safety Function	
Success Path	

Alternative Success Paths	
Necessary Support Systems	Primary Rig AC Power; Secondary (UPS) Rig AC Power; 5k Surface Hydraulic Supply; Subsea AC Power; 3k Accumulator Pilot Supply (Pod Dependent)
Threat Scenarios	<u>Limitations:</u> Wellbore must be clear of possible obstructions and at proper pressures for closure.

B.2 Success Path – Support Systems

MUX System



Alternative Success Paths

Necessary Support Systems

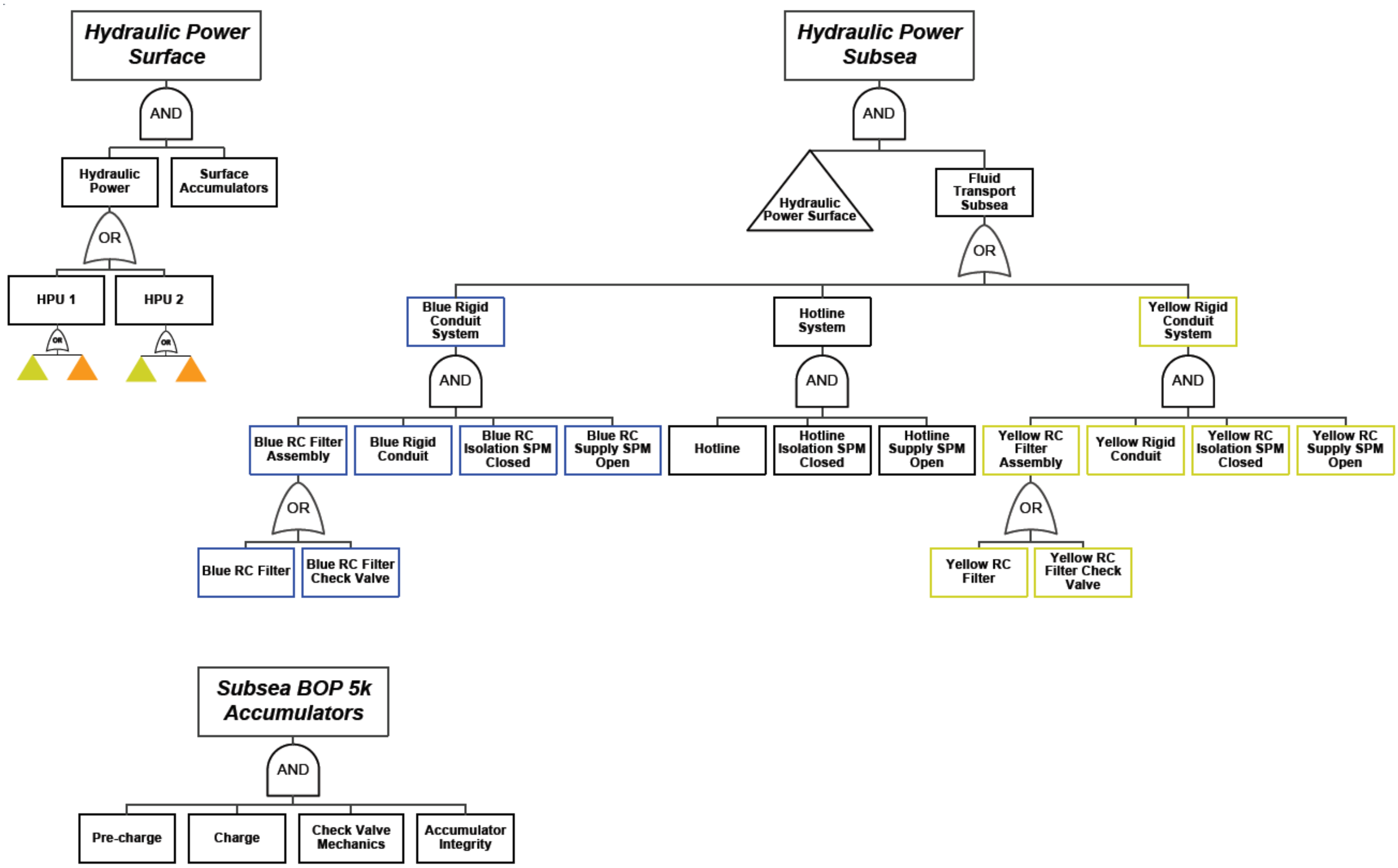
Primary Rig AC Power *Secondary (UPS) Rig AC Power*

Threat Scenarios

Applicability

Safety Function

Success Path



Alternative Success Paths

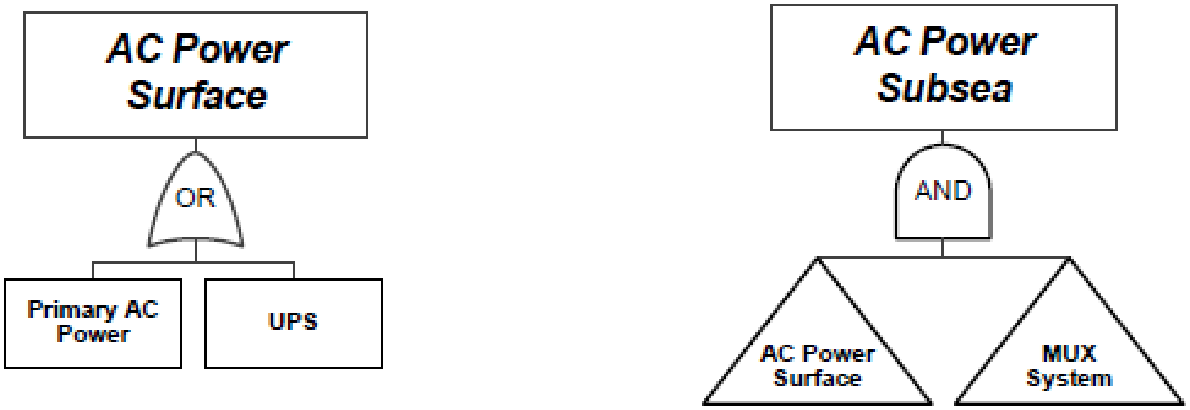
Necessary Support Systems

Primary Rig AC Power *Secondary (UPS) Rig AC Power*

Threat Scenarios

Applicability	Conventional Drilling
Safety Function	

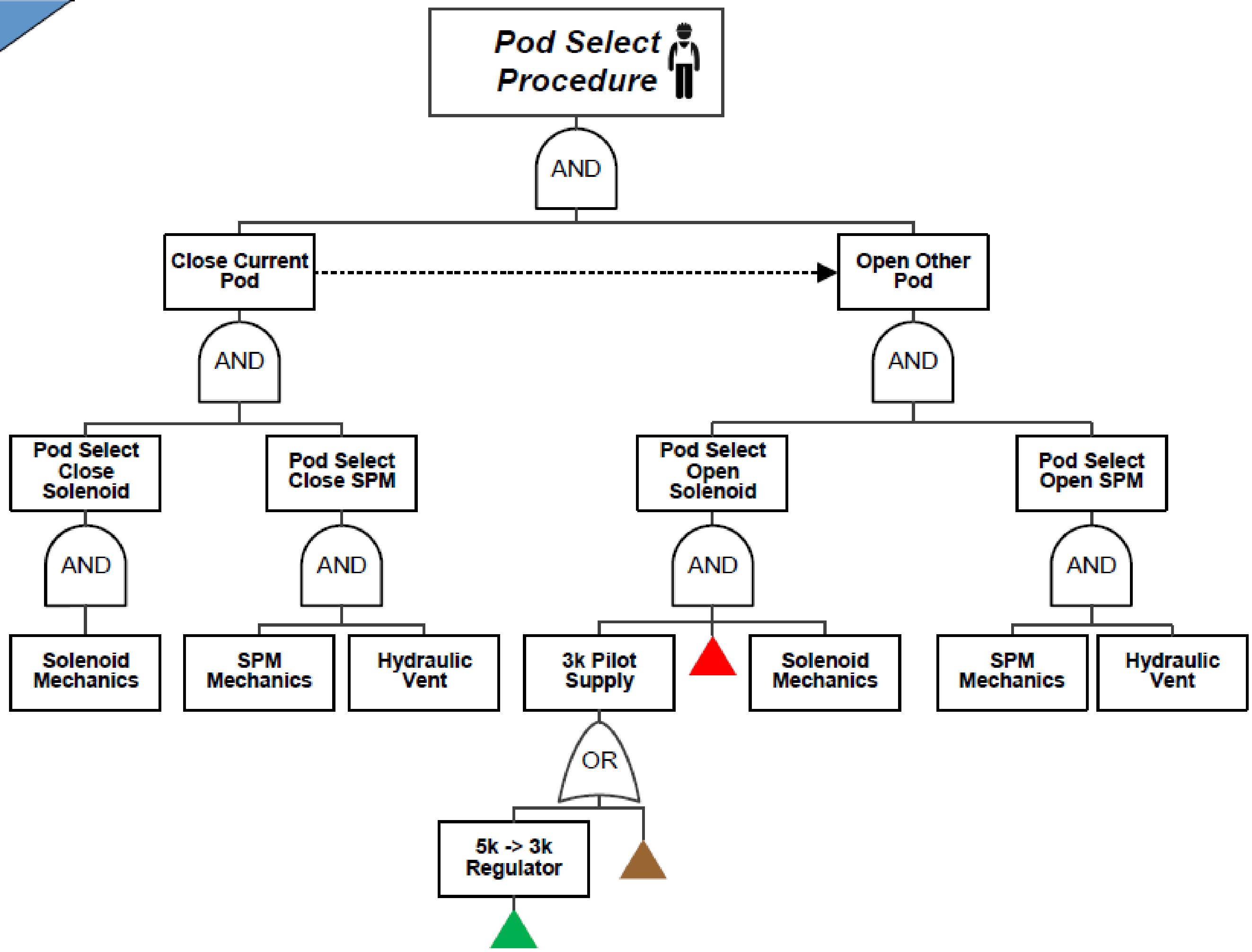
Success Path



Alternative Success Paths	
Necessary Support Systems	
Threat Scenarios	

Applicability	
Safety Function	

Success Path



Alternative Success Paths	
Necessary Support Systems	*5k Hydraulic Supply From Surface* *Human Action* *(Operation)* *Subsea AC Power* *3k Accumulator Pilot Supply (Pod Dependent)*
Threat Scenarios	

Appendix C: API Spec 16A – PR1/PR2 Comparison

Table A - 3 through Table A - 8 contain a comparison of the API 16A 4th edition PR1 and PR2 minimum performance criteria for rams and annulars. Differences have been highlighted in red. If a ram/annular satisfies the requirements of the PR2 level, then it also satisfies PR1. As defined in the standard, "reportable" means that a test shall be performed and documentation shall be provided to the purchaser of the equipment, in accordance with requirements 4.8 or 4.9, which mandates the information that must be within the operating manuals. As mentioned in Section 4.2.1, there are also differences between the PR1 and PR2 levels for operating manual requirements, as PR2 mandates additional detail on the sealing characteristics test, the stripping life test, the hang-off test, and the shear ram test.

Table A - 3: Minimum Performance Criteria for Ram BOPs [17]

Test	*PR1 Minimum Performance Criteria*	*PR2 Minimum Performance Criteria*
Ram Access	*200 cycles with 10 pressure cycles*	*200 cycles with 10 pressure cycles*
Fatigue	*Reportable*	*52 Pressure Cycles*
Ram Locking	*1 locking pressure cycle*	*52 locking pressure cycles*
Low Temperature	*3 Pressure Cycles*	*3 Pressure Cycles*
Continuous High Temperature	*N/A*	*10 Pressure Cycles*
Extreme High Temperature	*1 hour hold time*	*1 hour hold time*

Table A - 4: Minimum Performance Criteria for VBRs [17]

Test	*PR1 Minimum Performance Criteria*	*PR2 Minimum Performance Criteria*
Sealing Characteristics	*Reportable*	*Reportable*
Fatigue	*Reportable*	*28 Pressure Cycles*
Stripping	*Reportable*	*Reportable*
Hang-off	*Reportable*	*Reportable*
Low Temperature	*3 Pressure Cycles*	*3 Pressure Cycles*
Continuous High Temperature	*N/A*	*10 Pressure Cycles*
Extreme High Temperature	*1 hour hold time*	*1 hour hold time*

Table A - 5: Test Mandrel Sizes for Ram Testing [17]

Nominal (in)	*PR1 (in)*	*PR2 (in)*
7 1/16	*3 ½*	*3 ½*
9	*3 ½*	*3 ½*
11	*5*	*5*
13 5/8	*5*	*5*
16 ¾	*5*	*5*
18 ¾	*5*	*5 and one size ≥ 10 ¾*
20 ¾	*5*	*5 and one size ≥ 10 ¾*
21 ¼	*5*	*5 and one size ≥ 10 ¾*
26 ¾	*5*	*5 and one size ≥ 10 ¾*
30	*5*	*5 and one size ≥ 10 ¾*

Table A - 6: Minimum Performance Criteria for Annular BOPs [17]

Test	*PR1 Minimum Performance Criteria*	*PR2 Minimum Performance Criteria*
Packer Access	*Reportable*	*60 cycles with 3 pressure cycles*
Fatigue	*Reportable*	*26 Pressure Cycles*
Low Temperature	*3 Pressure Cycles*	*3 Pressure Cycles*
Continuous High Temperature	*N/A*	*10 Pressure Cycles*
Extreme High Temperature	*1 hour hold time*	*1 hour hold time*

Table A - 7: Minimum Performance Criteria for Annular Packers [17]

Test	PR1 Minimum Performance Criteria	PR2 Minimum Performance Criteria
Sealing Characteristics	*Reportable*	*Reportable*
Fatigue	*Reportable*	*28 Pressure Cycles*
Extended Range Operational Characteristics	*N/A*	*Optional test*
Stripping	*Reportable*	*50 stripping cycles*
Low Temperature	*3 Pressure Cycles*	*3 Pressure Cycles*
Continuous High Temperature	*N/A*	*10 Pressure Cycles*
Extreme High Temperature	*1 hour hold time*	*1 hour hold time*
Low Temperature Drift Characteristics	*N/A*	*Reportable*

Table A - 8: Test Mandrel Sizes for Annular Testing [17]

Nominal (in)	PR1 (in)	PR2 (in)
7 1/16	*3 ½*	*3 ½*
9	*3 ½*	*3 ½*
11	*5*	*Min and Max**
13 5/8	*5*	*Min and Max**
16 ¾	*5*	*Min and Max**
18 ¾ +	*5*	*Min and Max**

* Minimum and Maximum is the mandrel size range of the annular packing unit at the rated working pressure determined by the manufacturer.

Appendix D: Review of Past Pipe Ram, VBR, and Annular Failures

The following tables outline the annular and pipe ram/VBR failures identified in three past BOP studies (ref. [4, 6, 13]). In each table, the "failure category" corresponds to the failure classification provided in the report. The "failure identification" and notes categories are part of the current study. The purpose of the failure review was to attempt to identify previous elastomer failures and classify the identification method. Many failures were screened from the analysis, as they were not related to elastomer failures, such as failures of the control system, or were part of maintenance activities.

Table A - 9: SINTEF Phase II – Annular Failures

Failure	*Failure Category*	*Failure Identification*	*Note*
1	*Internal Leakage (on the rig)*	*Stump PT*	*Cap seal leakage.*
2	*Internal Leakage (on the wellhead)*	*Screened*	*Power hydraulic fluid leaking from close to open chamber. Not wellbore leak.*
3	*Internal Leakage (on the wellhead)*	*PT After Casing/Liner*	*Leak from operating chamber to wellbore.*
4	*Internal Leakage (on the wellhead)*	*Operations*	*Annular rubber returns after stripping during well control operation. Subsequent BOP pressure test.*
5	*Internal Leakage (on the wellhead)*	*Operations*	*Annular leaking during well control operations.*
6	*Internal Leakage (on the wellhead)*	*Installation PT*	*Unable to test upper annular. Appears due to piston seal leak, unclear if leak into wellbore.*

Table A - 10: SINTEF Phase II – Ram Failures

Failure	*Failure Category*	*Failure Identification*	*Note*
1	*External Leakage*	*Screened*	*Blind shear ram.*
2	*Internal Leakage (through closed ram)*	*Screened*	*Blind shear ram.*
3	*Internal Leakage (through closed ram)*	*PT After Casing/Liner*	*LPR passed function but failed to pressure test (missing VBR flexpacker)*
4	*Internal Leakage (through closed ram)*	*Screened*	*Suspected wellhead connector leakage, could not be confirmed. Repeat test passed.*
5	*Internal Leakage (through closed ram)*	*PT After Casing/Liner*	*VBR would not pressure test on 3½" but would test on 4½".*

Table A - 11: WEST JIP – Annular Failures

Failure	Failure Category	Failure Identification	Note
1	Pre-latch	Operation	Damage due to attempts to force a full-bore tool through the annular before allowing time for element to fully open. Damage inspection while on rig.
2	Pre-latch	Screened	Relief valve issue.
3	Pre-latch	Stump PT	Lower annular latched head seal leak.
4	Pre-latch	Screened	Removed milling swarf (not a failure).
5	Pre-latch	Stump PT	Lower annular, wellbore seal leaking (from wellbore to operating chamber).
6	Pre-latch	Screened	Swarf removed during maintenance.
7	Pre-latch	Stump PT	Upper annular failed to maintain pressure.
8	Pre-latch	Screened	Repair swarf damage to piston.
9	Pre-latch	Screened	Repair swarf damage to piston.
10	Pre-latch	Operation	Wellbore fluid observed venting from the weep hold. LMRP pulled to rig for repair.
11	Pre-latch	Screened	Deformation of open chamber head.
12	Pre-latch	Screened	Packer element worn from stripping (unclear if failure had occurred).
13	Pre-latch	Stump PT	Issues with lower annular during pre-latch testing, annular element changed.
14	Wellhead	Screened	Function test failure.
15	Wellhead	Time-Based PT	Lower annular failed low test. Assumed to be time-based PT.
16	Wellhead	Unclear	Insufficient information.
17	Wellhead	Screened	Function test failure.
18	Wellhead	Unclear	Insufficient information.
19	Wellhead	Time-Based PT	Upper annular would not test (after use of calcium bromide). Assumed to be time-based PT.
20	Wellhead	PT After Event	Pressure test after kick, problems running test plug, upper annular would not test.
21	Wellhead	Screened	Function test.
22	Wellhead	Unclear	Insufficient information.
23	Wellhead	Screened	Open chamber piping leaking from bolting flange.
24	Wellhead	Unclear	Insufficient information.

Table A - 12: WEST JIP – Ram Failures

Failure	*Failure Category*	*Failure Identification*	*Note*
1	*Pre-latch*	*Screened*	*Tension studs leaked.*
2	*Pre-latch*	*Screened*	*Leak from open chamber bonnet.*
3	*Pre-latch*	*Stump PT (x2)*	*Middle and lower pipe rams failed locks-only pressure test.*
4	*Pre-latch*	*Screened*	*Shear rams.*
5	*Pre-latch*	*Screened*	*Shear rams.*
6	*Pre-latch*	*Screened*	*Pipe rams, open chamber leaking into close chamber and closing door hinge leak.*
7	*Pre-latch*	*Screened*	*Shear rams.*
8	*Pre-latch*	*Stump PT (x2)*	*While on the rig, two bonnets were leaking wellbore pressure (gaskets in poor condition).*
9	*Pre-latch*	*Screened*	*CX sealing area leak.*
10	*Pre-latch*	*Screened*	*Shear ram.*
11	*Pre-latch*	*Stump PT*	*Upper pipe ram would not test (ram locking system failure?).*
12	*Pre-latch*	*Screened*	*Shear ram.*
13	*Pre-latch*	*Screened*	*Shear ram.*
14	*Pre-latch*	*Screened*	*Shear ram.*
15	*Pre-latch*	*Screened*	*Wedgelock balance chamber bladders collapsed.*
16	*Pre-latch*	*Stump PT*	*Lower pipe ram failure due to piston rod seal leakage.*
17	*Pre-latch*	*Screened*	*Shear ram.*
18	*Pre-latch*	*Screened*	*Pipe ram cap screw failure.*
19	*Pre-latch*	*Screened*	*Information unclear, but there appears to be no failures, just maintenance issues with bonnets.*
20	*Pre-latch*	*Screened*	*Scoring found on lower pipe rams.*
21	*Pre-latch*	*Stump PT*	*Lower pipe rams failed low test, new ram packers installed.*
22	*Pre-latch*	*Screened*	*Damage found in upper seal seats in ram cavities.*
23	*Wellhead*	*PT After Casing/Liner*	*Lower fixed pipe rams would not test (but closed correctly).*
24	*Wellhead*	*PT After Event*	*Lower pipe ram would not test after cement squeeze job.*
25	*Wellhead*	*Screened*	*Function test.*
26	*Wellhead*	*Screened*	*Shuttle valve leak.*
27	*Wellhead*	*Screened*	*Open hose leak.*
28	*Wellhead*	*Screened*	*Open function leak.*
29	*Wellhead*	*Screened*	*Would not close from SEM B (worked from SEM A).*
30	*Wellhead*	*Screened*	*Function test.*
31	*Wellhead*	*Operation (x2)*	*While returning to normal operations after a hurricane, failures of ram locking devices on middle and lower pipe rams.*
32	*Wellhead*	*PT After Event*	*VBR failed during pressure test after milling and fishing.*

Table A - 13: Exprosoft– Annular Failures

Failure	*Failure Category*	*Failure Identification*	*Note*
1	Internal Leakage (through a closed annular)	Time-Based PT	Upper annular failure, piston seal leak to weep hole (found cut annular packer).
2	Internal Leakage (through a closed annular)	Installation PT	Annular would not test, changed element.
3	Internal Leakage (through a closed annular)	Time-Based PT	Annular would not test, changed rubber.
4	Internal Leakage (through a closed annular)	Installation PT	Upper annular failed to test, found leaking from upper vent ports, observed flaking from upper cylinder head.
5	Internal Leakage (through a closed annular)	Stump PT	With previous, leak found after pulling BOP to rig (spare annular on rig also found in failed state).
6	Internal Leakage (through a closed annular)	Installation PT	Upper annular failed to test, pulled and changed element.
7	Internal Leakage (through a closed annular)	Installation PT	With previous, lower annular failed to test, pulled and changed piston.
8	Internal Leakage (through a closed annular)	Operation	After kick, annular found leaking (likely due to stripping).
9	Internal Leakage (through a closed annular)	Operation	While circulating a kick, annular found leaking while stripping out of hole.
10	Internal Leakage (through a closed annular)	Installation PT	Lower annular leaking, changed piston and upper seals.
11	Internal Leakage (through a closed annular)	Installation PT	Lower annular failed to test, pulled and changed annular element.

Table A - 14: Exprosoft – Ram Failures

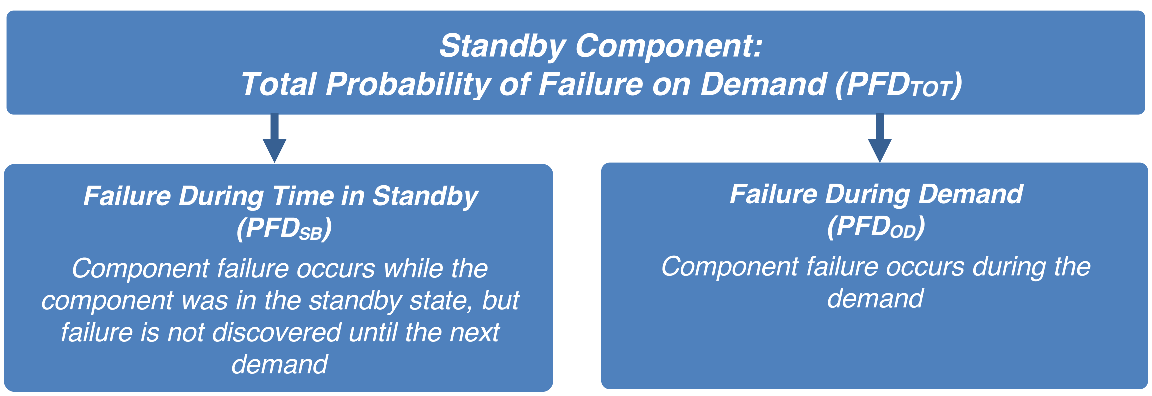
Failure	*Failure Category*	*Failure Identification*	*Note*
1	*External Leakage*	*Installation PT*	*Leak on upper pipe ram bonnet seals to environment (possible hydraulic fluid).*
2	*External Leakage*	*Screened*	*Shear ram.*
3	*Internal Leakage (leakage through a closed ram)*	*Installation PT*	*VBR would not test.*
4	*Internal Leakage (leakage through a closed ram)*	*Installation PT*	*Test ram found leaking.*
5	*Internal Leakage (leakage through a closed ram)*	*Installation PT*	*Test ram found leaking.*
6	*Internal Leakage (leakage through a closed ram)*	*PT After Casing/Liner (x2)*	*Upper and lower VBRs leaking. Changed ram elements.*
7	*Internal Leakage (leakage through a closed ram)*	*Screened*	*Shear ram.*
8	*Internal Leakage (leakage through a closed ram)*	*Stump PT*	*Middle pipe ram would not test, removed/replaced seals.*
9	*Internal Leakage (leakage through a closed ram)*	*Installation PT*	*With previous, observed middle pipe ram leaking after running BOP subsea.*
10	*Internal Leakage (leakage through a closed ram)*	*PT After Casing/Liner*	*Test ram found leaking.*
11	*Internal Leakage (leakage through a closed ram)*	*Screened*	*Shear ram.*
12	*Internal Leakage (leakage through a closed ram)*	*Stump PT*	*Middle pipe ram failed to test, changed ram.*
13	*Internal Leakage (leakage through a closed ram)*	*Installation PT*	*Recovered pieces of VBR while pulling test plug.*
14	*Internal Leakage (leakage through a closed ram)*	*PT After Event*	*After circulating a kick, a VBR would not test (ram element was two weeks old).*
15	*Internal Leakage (leakage through a closed ram)*	*Screened*	*Shear ram.*
16	*Internal Leakage (leakage through a closed ram)*	*PT After Casing/Liner*	*Middle VBR would not test, pulled for repairs.*
17	*Internal Leakage (leakage through a closed ram)*	*Stump PT*	*Ram closed on tool joint, dressed the ram.*

Appendix E: BOP Elastomer Reliability Analysis

E.1 Standby Component Failure Models

The pipe rams, VBRs, and annulars are standby components, meaning that they are not in continuous operation, but are called upon at specific instances to perform their designed task. Therefore, the wellbore sealing elastomers are also standby components, as the rams or annulars are normally in an open state and will close and seal the wellbore only when demanded. It is important to highlight that the terminology "standby" component refers to those BOP ram/annulars on the wellhead that are not in constant use. It does not refer to the backup BOP stack on the rig that is not installed. There are various models available to assess the reliability of standby components. This subsection examines the models in detail and determines the most appropriate model for the reliability analysis of the wellbore sealing elastomers.

When a standby component is called upon, there is a probability that the component may fail to perform the assigned task as designed. This is considered the probability of failure on demand (**PFD**). The standby component PFD can potentially have multiple contributors, as shown below. The component may have failed while it was in the standby state, but this failure was not discovered until the demand. Conversely, the demand itself may induce failure. These two aspects are sometimes referred to as the "standby failure" and "failure on demand" models [28]. These models are routinely applied to components and systems of high-reliability industries, such as the nuclear and offshore oil and gas sectors. The following subsections review each contributor and also discuss the potential impact of system "shocks" to each contributor.



E.1.1 Component Failure During Time in Standby

The first contributor to the standby component PFD is the possibility that the component has previously failed during its time in standby, but the failure is not discovered until the next demand or test[33]. For example, consider the standby component of a pressure relief value. During its time in standby, crud buildup or metal oxidation may result in the piston or poppet becoming stuck. However, this failure is not discovered until the next demand, when system

[33] For some standby components, it is possible to continuously monitor the state of the component while in standby. However, this is uncommon for most mechanical components, including elastomer wellbore seals.

pressure exceeds the relief threshold and the valve does not open. Although component failure occurred while the component was in standby, it is not discovered that the component is not operational until it is called upon to change state or perform an action.

The failure of a component while it is in standby is typically modeled by assuming Poisson Process, where failure is random but occurs at a known - typically constant[34] - rate (λ). Therefore, the contribution to the component PFD from standby failures can be calculated based on Eq. 1. As can be seen, the longer the component is in a standby state, the higher the PFD_{SB}. This is a consequence of the unknown status of the component (assuming constant monitoring is not possible). Since the component could fail while in standby, the longer the time period in standby, the greater the likelihood that the component will have failed before the next demand or test. Figure A - 3 illustrates the growth in PFD_{SB} with time in standby.

$$PFD_{SB}(t) = 1 - e^{-\lambda t} \approx \lambda t \qquad \text{Eq.1}$$

where,

$PFD_{SB}(t)$: Probability of failure on demand at time t due to standby failure
λ : Standby failure rate
t : Time in standby

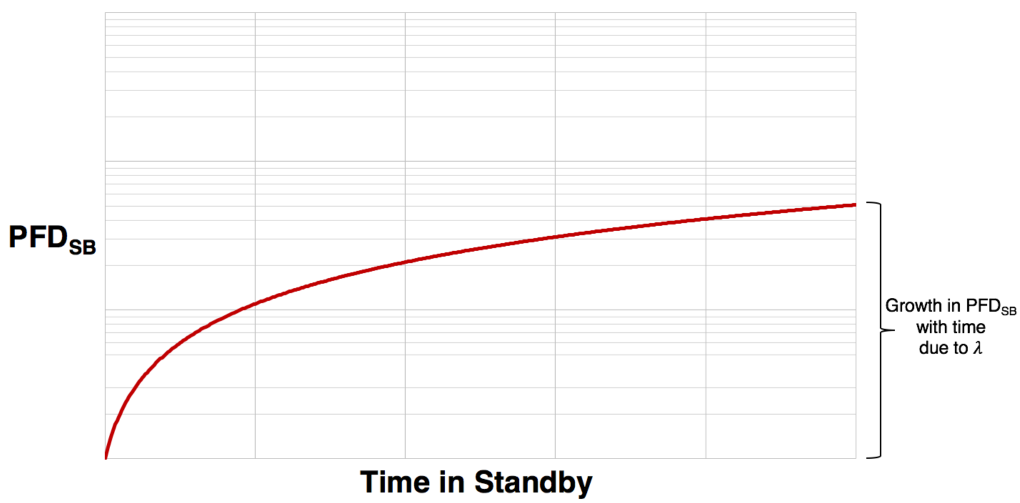


Figure A - 3: PFD_{SB} versus Time in Standby

A successful demand or proof test can restore confidence in the ability of the component to perform its mission by demonstrating that the component did not fail during the previous standby time interval. Therefore, a proof test or demand reduces the PFD_{SB} to its original value. As illustrated in Figure A - 4, the standby time interval between demands or proof tests then has a direct impact on the maximum and average PFD_{SB} of the component. The average PFD_{SB} can be calculated following Eq. 2. It is possible that a proof test may not be capable of exposing all potential failures. These are called imperfect or partial proof tests and reduce the PFD_{SB}, but not to the original value (see ref [32] for more detail).

[34] For systems with non-constant failure rates, see refs [29] and [30], or Non-Homogeneous Poisson Processes (NHPP) [31].

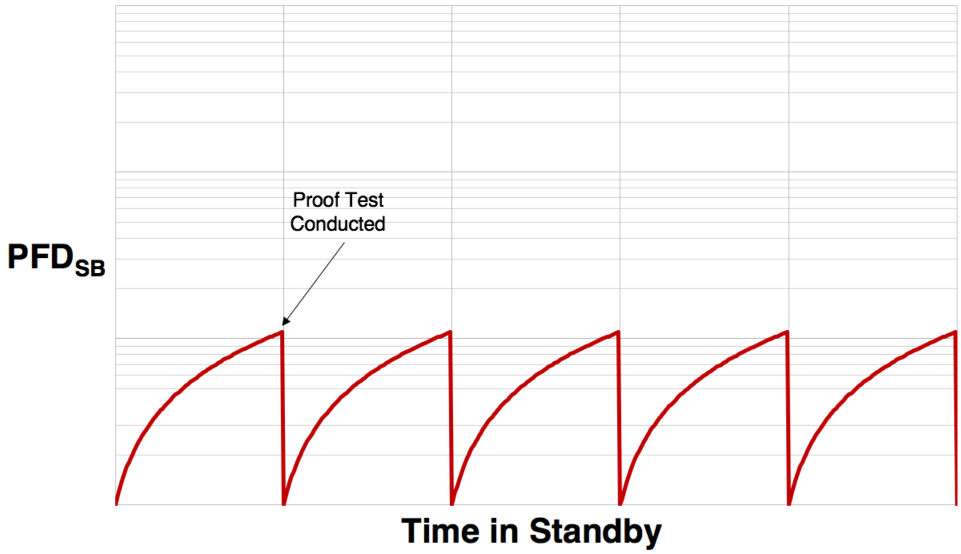


Figure A - 4: PFD$_{SB}$ with Proof Test[35]

$$PFD_{SB_{avg}} = 1 - \frac{1 - e^{-\lambda T}}{\lambda T} \approx \frac{\lambda T}{2} \qquad \text{Eq.2}$$

where,

$PFD_{SB_{avg}}$: Average probability of failure on demand at time t due to standby failure
λ : Standby failure rate
T : Time interval between proof tests

Typically, a proof testing interval is established that maintains the peak component PFD$_{SB}$ (or average PFD$_{SB}$) below a certain threshold, such as a safety integrity level (SIL) [33], as shown in Figure A - 5. The rate at which the PFD increases with time is directly dependent on the standby failure rate (λ). A higher failure rate will cause a more rapid increase in the PFD$_{SB}$ and will likely necessitate a more frequent proof test of the system.

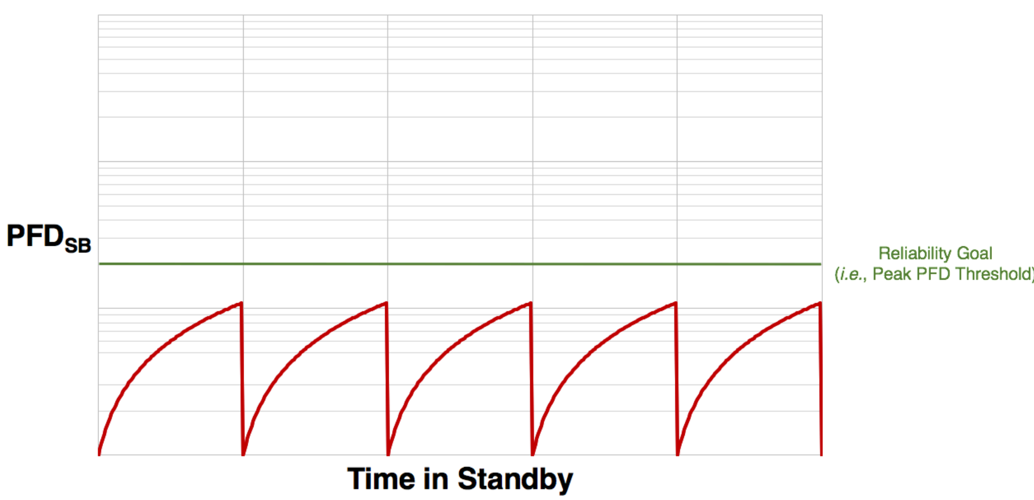


Figure A - 5: PFD$_{SB}$ versus Reliability Goal

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[35] Figure assumes perfect proof test.

Many analyses of standby component reliability will assume that standby failure is the only factor of PFD. This is a popular choice because the only information necessary to estimate the standby failure rate (λ) is the number of failures observed and time in standby. The latter of which is typically known based on documented testing intervals. This provides a straightforward approach to calculating component PFD based on past data, when detailed information about component failures and demands is not known. Such an approach has also been used previously in studies of BOP reliability [4, 6, 13].

E.1.2 Component Failure During Demand

In contrast to component failure during its time in standby, failure may also potentially occur during the demand itself. For example, consider an emergency diesel generator that is in standby. During a demand, the diesel generator may fail due to a failure of the crankshaft. While it is possible that the crankshaft had failed previously while in non-operational standby, the likely cause of failure was the stresses imposed on the crankshaft during engine startup.

Modeling the occurrence of failure due to the demand utilizes a binomial distribution, where the likelihood of failure during a demand is p. Since the probability of failure is not a rate (*i.e.*, not dependent on time in standby), the probability of failure p does not necessarily increase with the passage of time in standby. Therefore, the time period between proof tests is typically assumed to have no impact on the component PFD_{OD}, as shown in Eq. 3. This results in the PFD_{OD} curve shown in Figure A - 6.

$$PFD_{OD} = p \qquad \text{Eq.3}$$

where,

$PFD_{OD}(t)$: Probability of failure on demand at time t due to demand − induced failure
p : Probability of failure due to demand

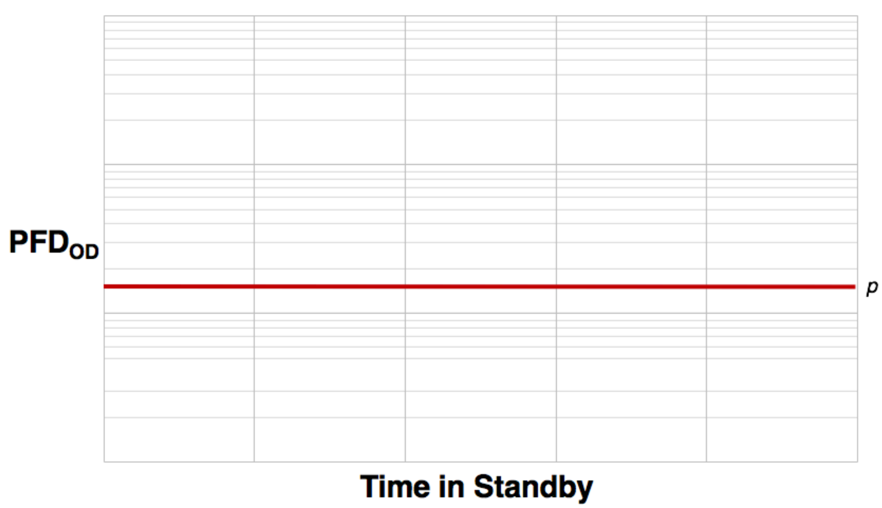

Figure A - 6: PFD_{OD} versus Time[36]

[36] Figure assumes no changes to p due to events or actions while the component is in standby.

To estimate p for a component, all that is needed is the number of observed failures and the number of demands. However, depending on the component, this approach can be challenging since the number of demands is not always recorded.

Although the probability of failure during a demand p is usually assumed to be constant with time, it is possible that events or actions may change the value of p. However, accounting for these changes is rare for most analyses that model failure during a demand, as it would require even more detailed information or data (beyond the number of failures and number of demands), which is typically not present. Additional discussion regarding adjusting p during the time in standby is provided in Section E.1.4.

E.1.3 Combining Failure Contributors

Taking both failure contributors, failure during standby and failure during the demand, into consideration results in the model shown in Eq. 4. This model attempts to account for both contributors to the total component PFD[37]. Figure A - 7 shows how the PFD_{TOT} changes with time in standby based on these two factors. While the first factor, p, is present from the beginning of the time in standby of the component, the second (time-dependent, based on the failure rate) factor increases with time.

$$PFD_{TOT}(t) = PFD_{OD} + PFD_{SB} \qquad \text{Eq.4}$$
$$PFD_{TOT}(t) = p + (1-p) \times (1-e^{-\lambda t}) \approx p + \lambda t$$

where,

$PFD_{TOT}(t)$: Total probability of failure on demand at time t
p : Probability of failure due to demand (PFD_{OD})
λ : Standby failure rate
t : Time

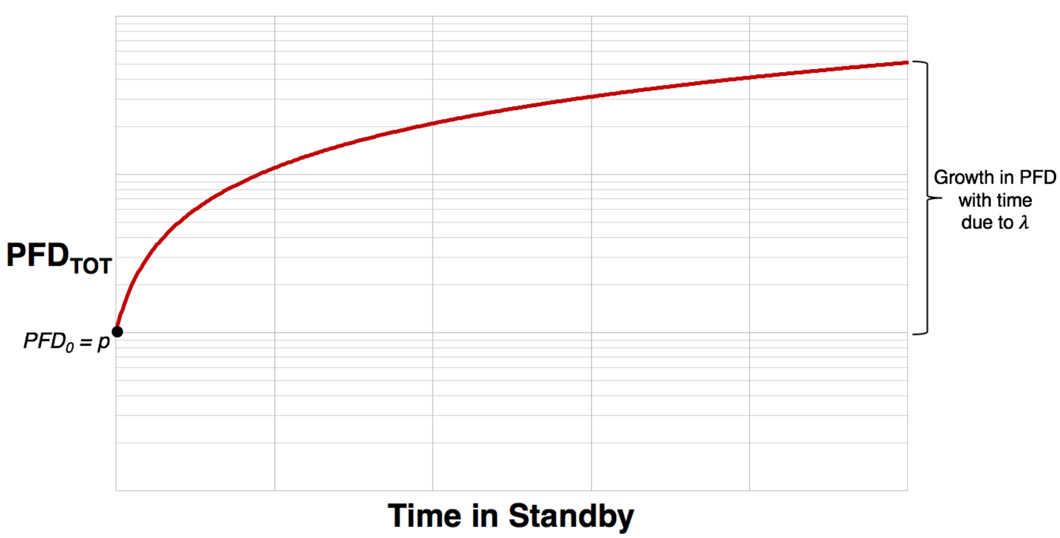

Figure A - 7: Change in PFD_{TOT} with Time, No Proof Testing

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[37] The combined model is sometimes called the "$q + \lambda t$" model [34].

In the total PFD model, a proof test still yields some benefit, as it can reduce the contribution from PFD_{SB}, as shown in Figure A - 8. However, the proof test cannot reduce the contribution from PFD_{OD} (p), as it is the inherent property of the likelihood of failure from the next demand based on the state of the component. The average PFD_{TOT} of the component can be calculated using Eq. 5, which utilizes the proof testing interval.

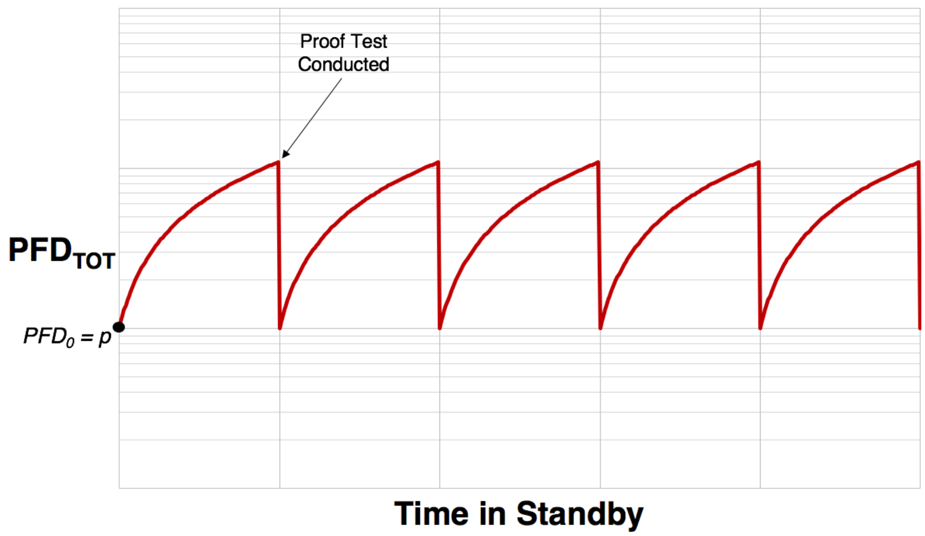

Figure A - 8: Change in PFD_{TOT} with Time – Combined Model with Proof Test[38]

$$PFD_{TOT\,avg} = p + 1 - \frac{1 - e^{-\lambda T}}{\lambda T} \approx p + \frac{\lambda T}{2} \qquad \text{Eq.5}$$

where,

$PFD_{TOT_{avg}}$: Average total probability of failure on demand
p : Probability of failure due to demand (PFD_{OD})
λ : Standby failure rate
T : Time interval between proof tests

E.1.4 Application of Shock Models

In addition to the models presented in the previous subsections, "shock models" are becoming increasingly popular for component reliability analysis. Shock models should not be viewed as completely distinct from the two aspects described above, but as complementary. Shock models assume that components undergo discrete "shock" events that damage or degrade the component. These shocks can cause immediate failure (fatal shocks) or cause failure due to cumulative damage[39]. Additional detail on the theory of shock models can be found in ref [36]. What is reviewed here is the implications on the parameters of the model described in the preceding subsection.

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[38] Figure assumes that p is constant (no changes to p due to events or actions while the component is in standby or from the proof tests).

[39] A shock model that considers both types of shock failure is often called a mixed shock model [35].

A standby component can be subjected to a shock in multiple ways. First, the demands themselves may be viewed as a shock, if they result in component fatigue or degradation. In addition, a shock can occur while the component is in standby. For example, if environmental conditions were to change rapidly and impact the performance of the component. For either type of shock, there are multiple potential repercussions on component reliability. First, the probability of the component failing during the next demand may increase (PFD_{OD}, variable p of Eq. 3), as the component has now incurred more degradation or damage than in its previous state. In addition, the failure rate (variable λ of PFD_{SB}) could also increase. This may be due to the increase in damage, which could make the probability of sudden failure of the component during its time in standby more likely. Figure A - 9 and Figure A - 10 present both possibilities. It is possible for the shock event to impact both the failure rate and the probability of failure at the next demand, as shown in Figure A - 11.

If the shock is of sufficient magnitude, it could cause immediate failure (a fatal shock). This can be depicted on the PFD plot as either p becoming a value of one, meaning certain failure at the next demand, or possibly an extremely high failure rate (λ), meaning failure occurs immediately following the shock event. The repercussion of the shock is the same either way it is depicted, with failure guaranteed at the next demand.

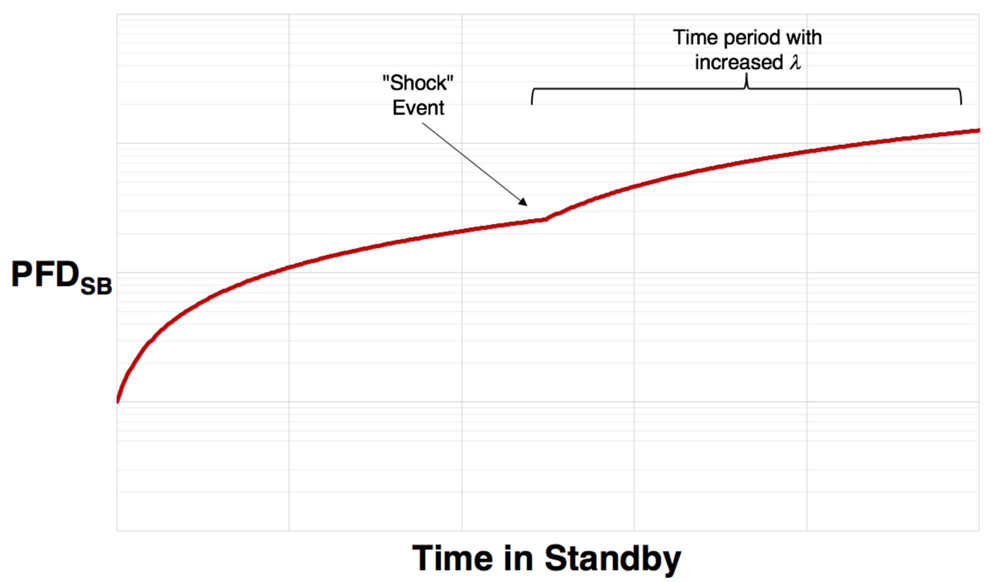


Figure A - 9: PFD_{SB} – Shock Model – Increase in Failure Rate (λ)[40]

[40] The “shock” included here is assumed not to be a demand.

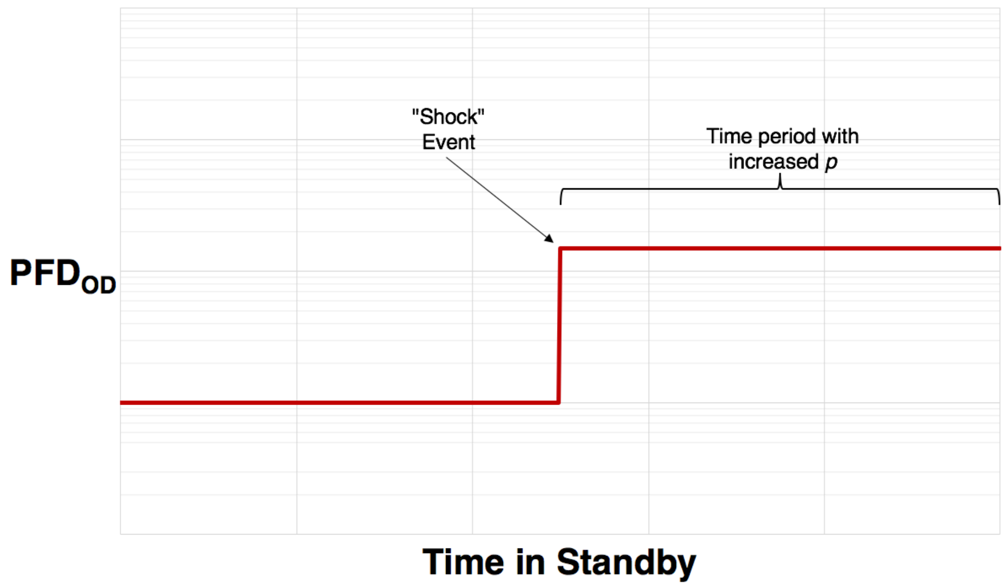


Figure A - 10: PFD$_{OD}$ – Shock Model – Increase in Failure Probability (p)

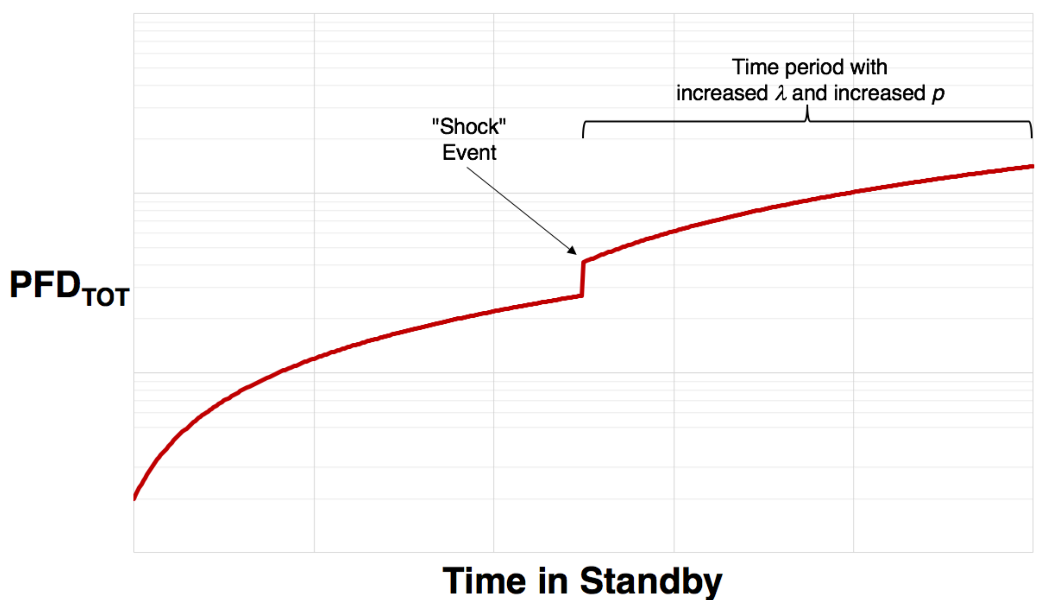


Figure A - 11: PFD$_{TOT}$ – Shock Model – Increase in λ and p

E.2 Elastomer Reliability Assessment

With the models and information reviewed in the previous section, a reliability model of the wellbore sealing elastomers can be constructed. This model attempts to capture both contributors to PFD: PFD$_{SB}$ and PFD$_{OD}$. In addition, aspects of shock models and component fatigue are instituted to assist with incorporating findings from data. Once developed, the model is then utilized to examine the impact of extending the pressure testing interval for select scenarios. Before the model is utilized, the failure data presented in Section 4.2.3 is reviewed for general insights regarding elastomer reliability.

E.2.1 General Data Trends and Insights

There are several apparent trends from the elastomer failure data presented in Section 4.2.3. First, the majority of elastomer failures were identified during the stump or installation pressure test. Additionally, a large number of failures were found either during a degrading operation or by a pressure test after a particular operation or after running casing/liner. The smallest number of elastomer failures were identified by the time-based pressure test. Several general conclusions can be inferred from this information.

First, the comparatively high number of failures on stump/installation pressure tests appears to indicate that the dominant failure mechanism for the elastomers is the category related to manufacturing defects and/or improper handling and installation, as this is the only failure mechanism category that impacts the elastomers before they have entered service, meaning before they have been placed in standby on the wellhead. This also highlights that the largest impact of this failure mechanism category is on the probability of failure during the next demand (PFD_{OD} or p) and not the failure rate during standby (λ), as the identified failures occurred during the first series of demands before the component was ever placed in standby.

Second, the lack of identified failures outside of the stump/installation pressure test and the operation-based tests/demands indicates that there are likely very few elastomer failures occurring due to fatigue. If this failure mechanism was more prominent, there would be an expectation to see more failures during time-based pressure tests without an additional contributor from a specific operation-based degrading/damaging event. There are likely several reasons for the lack of fatigue-induced failures. First, the elastomers are specifically designed and tested for this application. Second, as described in Section 4.2.2, most operators are replacing the wellbore sealing elastomers before their predicted fatigue failure thresholds. The implication for the reliability model is two-fold. First, the fatigue contribution to the increase in the probability of failure during the next demand (PFD_{OD} or p) is likely small for the cyclic ratio region where the elastomers are operating[41], as elastomer replacement is occurring before the cumulative degradation level is having a significant effect on reliability. Second, the probability of sudden failure while in standby (failure rate – λ) due to the fatigue failure mechanism also appears small, as failures are not presenting themselves during the time-based pressure tests, which indicates that the elastomers are generally not failing while in standby.

Lastly, the presence of elastomer failures detected during damaging/degrading events, or through a pressure test immediately following such an event, indicates that these wellbore events or conditions do pose a threat to elastomer reliability. However, it appears that such events are rare and industry is, in general, recognizing when such events have occurred and is taking steps to verify elastomer performance, such as conducting pressure tests following the events. The fact that elastomer failures are occurring either during the events or during the pressure tests immediately after the events indicates that these "shocks" are either fatal or result in sufficient damage to make the probability of failure during the next demand (PFD_{OD} or p) very high. The fact that failures are not being identified at a later time, through the time-based pressure test, signifies that the impact on the growth of the standby failure rate (λ) is

[41] The cyclic ratio is the number of cycles experienced divided by design life (cycles) of the component or material.

small for those elastomers that survive the initial shock. It could be that the degrading and damaging events are falling into two general categories. Either the event is severe enough to cause immediate failure (fatal) or the events are of insufficient severity to have an appreciable subsequent impact on the standby failure rate.

E.2.2 Reliability Analysis of Scenarios

In this subsection, the impact on elastomer reliability of extending the time-based pressure testing interval is assessed for a series of potential scenarios. The scenarios are intended to coincide with the three failure mechanism categories described in Section 4.2.2. An attempt is made to quantitatively assess elastomer reliability for each scenario, based on past data. However, it should be noted that the calculated PFD values are only estimates utilizing imperfect data and large uncertainties. **The main purpose of the quantitative analysis is not the determination of the absolute values for PFD, but to compare the magnitude of the multiple, competing failure mechanism effects and to provide insights regarding how changes in the pressure testing interval may impact the PFD.**

Scenario 1: Improper Handling/Installation or Material Defect

The first scenario examined is the event where a wellbore sealing elastomer is damaged or degraded prior to service due to improper handling/installation or a material defect. As described in the preceding section, such an event will like result in an increase in the probability of failure during the next demand (PFD_{OD} or *p*). Specifically, damage to the elastomer before it enters service will impact the initial value of PFD_{OD}, as shown in Figure A - 12.

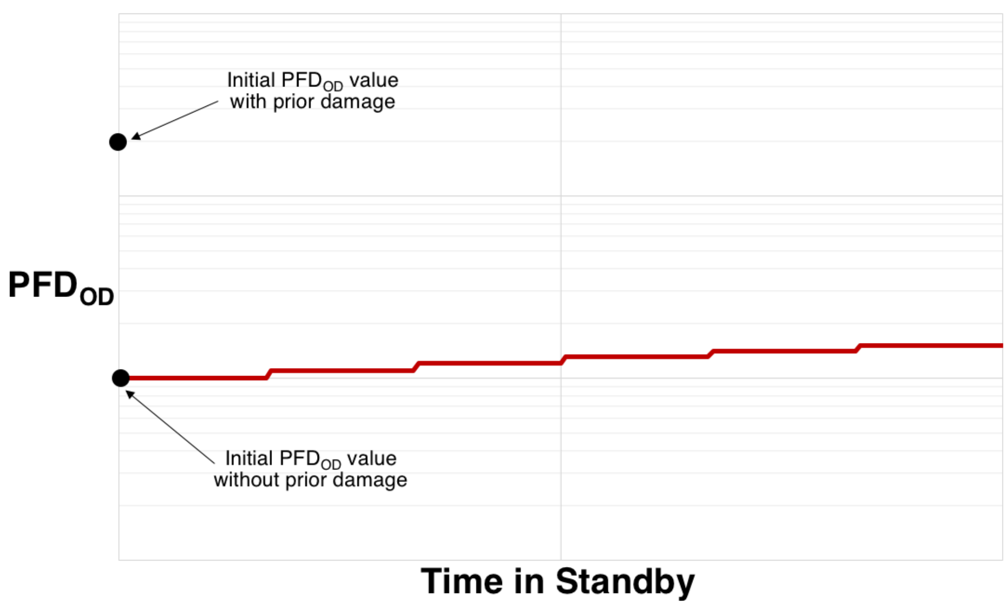


Figure A - 12: Example Increase in PFD_{OD} Due to Improper Handling/Installation or Material Defect

As discussed in Section 4.2.3, the majority of elastomer failures were discovered during the stump and installation pressure tests. This illustrates the importance of these tests for screening damaged, degraded, or faulty elastomers before they enter service. However, while these initial pressure tests are vital to potentially identifying these degraded components, the pressure test itself, even if successful, does not repair the component or reduce the PFD contribution from PFD_{OD}. This is because the pressure test simply signifies whether the component has failed previously or happens to fail on that particular demand. If a damaged, degraded, or faulty elastomer is able to successfully pass the stump and installation tests, further pressure testing cannot restore the PFD_{OD} to that of an undamaged component and likely only increases degradation or damage further.

Therefore, the frequency of the time-based pressure test after the initial stump and installation test likely has very little impact on preventing future failure of the elastomer. It is a common saying that a manufacturer cannot “test-in” quality to a product after it is built. In much the same way, the time-based pressure test cannot “test-in” reliability into a previously damaged component. Instead, the primary method in which failures from this mechanism can be avoided is through prevention.

Quality controls during manufacturing, handling, and installation are the key pathways to reducing failures from this failure mechanism. Quality controls should be a seamless process from manufacturing to transport/handling and eventual installation. This includes proper quality controls during the manufacturing process to screen products that could contain defects. On the customer side, it is necessary to understand manufacturer recommendations regarding elastomer storage and handling. As Section 4.2.2 mentioned, elastomers can be severely degraded due to exposure to UV light or extreme temperatures. Lastly, ensuring the BOP service staff are properly trained to install the specific equipment on the BOP is vital to avoiding installation errors.

Since data was available regarding elastomer failures identified during the stump and installation pressure tests, an attempt was made at determining the likelihood of elastomer failures during these tests for informational purposes. The probability of an annular failing the stump or installation pressure test was estimated based on the data presented in Section 4.2.3. These results are presented in Table A - 15 and graphically in Figure A - 13. As the results show, the findings of the three past studies are fairly consistent regarding the likelihood of annular failure during the stump/installation test. Although there is uncertainty regarding the findings of the current study (discussed in Section 4.2.3), it appears that there has been a decrease in the probability of annular failure during these tests in recent years. Table A - 16 and Figure A - 14 contain equivalent results for the pipe rams and VBRs, with similar trends.

Table A - 15: Annular – Failures during Stump/Installation Pressure Tests[42]

Study	Failures during Stump/Installation PT	Number of Stump/Installation PTs[1]	Probability of Failure[2]		
			Mean	5th	95th
SINTEF Phase II	2	661	3.78E-03	8.67E-04	8.35E-03
WEST	4	1,835	2.45E-03	9.06E-04	4.60E-03
Exprosoft	7	1,924	3.90E-03	1.89E-03	6.49E-03
Total Past Studies	**13**	**4,420**	**3.05E-03**	**1.83E-03**	**4.53E-03**
Current Study	18	~13,800	9.06E-04	5.29E-04	1.36E-03

[1] The number of stump and installation tests performed was estimated using the average number of annulars per BOP and an assumption of two stump and two installation tests per well.
[2] Probability of wellbore sealing elastomer failure during a stump or installation pressure test.

Table A - 16: Pipe Ram and VBR – Failure during Stump/Installation Pressure Tests

Study	Failures during Stump/Installation PT	Number of Stump/Installation PTs[1]	Probability of Failure[2]		
			Mean	5th	95th
SINTEF Phase II	0	1,036	4.82E-04	1.90E-06	1.85E-03
WEST	7	3,204	2.34E-03	1.13E-03	3.90E-03
Exprosoft	8	2,663	3.19E-03	1.63E-03	5.17E-03
Total Past Studies	**15**	**6,903**	**2.25E-03**	**1.40E-03**	**3.26E-03**
Current Study	6	~22,200	2.93E-04	1.33E-04	5.04E-04

[1] The number of stump and installation tests performed was estimated using the average number of pipe rams/VBRs per BOP and an assumption of two stump and two installation tests per well.
[2] Probability of wellbore sealing elastomer failure during a stump or installation pressure test.

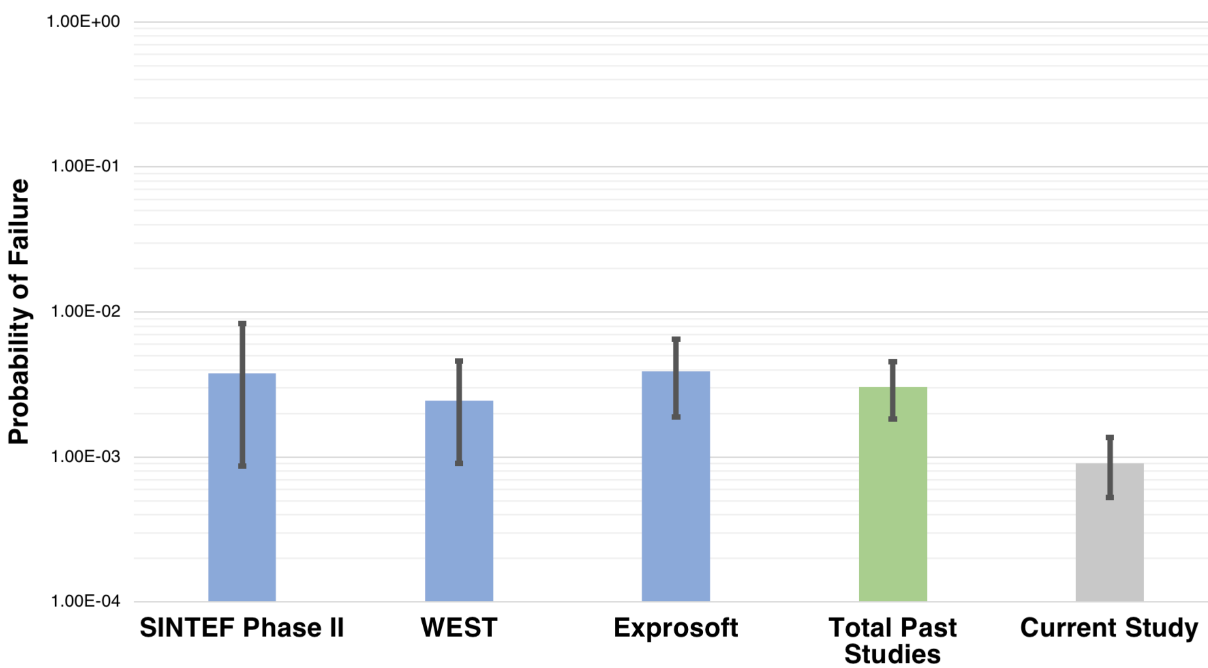


Figure A - 13: Annular – Stump/Installation PT Probability of Failure

[42] All uncertainties in this section are calculated using a Bayesian analysis with a Jeffreys non-informative prior.

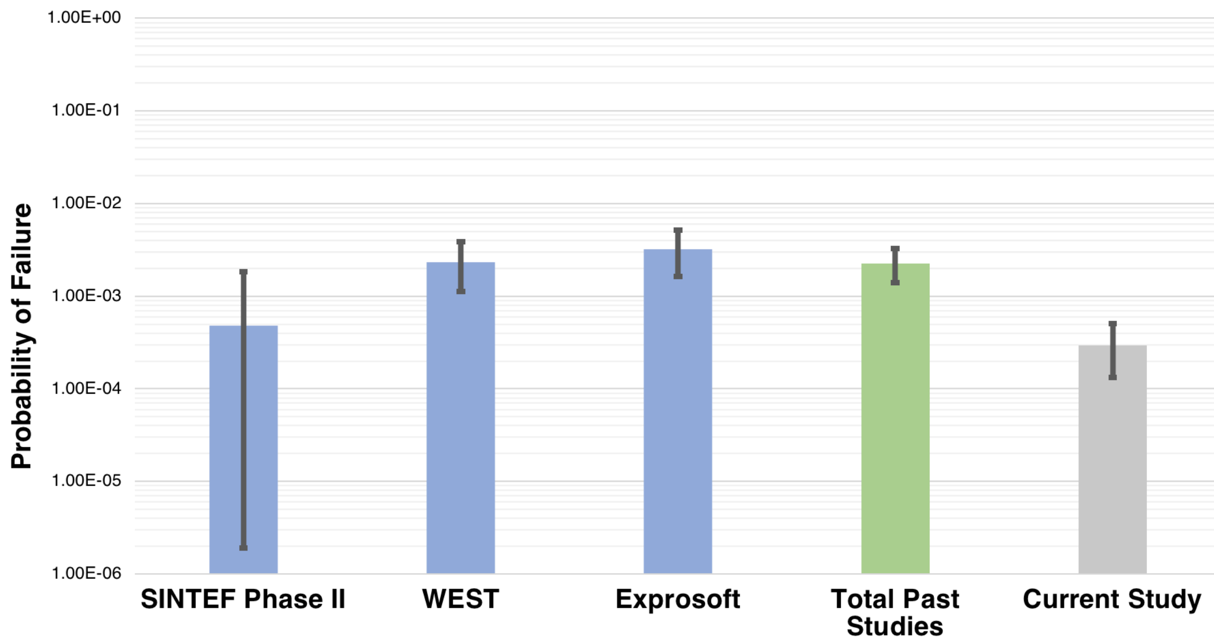


Figure A - 14: Pipe Ram and VBR – Stump/Installation PT Probability of Failure

Scenario 2: Degrading/Damaging Wellbore Event or Condition

The next scenario examined involves an elastomer that has successfully passed the stump and installation pressure tests, but then experiences a damaging or degrading event or wellbore condition during operation on the wellhead. As described in Section E.1.4. and Figure A - 11, such system shocks could cause an increase in the probability of failure during the next demand p, or the standby failure rate λ. In addition, the shocks can cause immediately fatal damage, or increase cumulative damage. As stated in Section E.2.1., a review of past data appears to indicate that degrading events/conditions can cause failures that are identified through a pressure test performed after the occurrence. However, there does not appear to be a large number of standby failures that occur at a later time after the event, indicating that the primary repercussion is on the probability of failure during the next demand p, not an increase in the subsequent standby failure rate.

In either case, the primary concern is the impact of subsequent time-based pressure tests on system PFD_{TOT}. As with scenario one, the pressure test cannot fix the irreversible damage that has occurred to the elastomer, but can only identify whether the damage is severe enough to result in pressure test failure or an observable degradation in performance. While the time-based pressure test could help reduce the growth in the PFD_{SB} contribution if the standby failure rate λ has increased, it will also cause a further increase in PFD_{OD} due to the continued growth in cumulative fatigue damage. Unlike the first scenario, a quantitative assessment of the likelihood of elastomer failure after damaging/degrading event was not performed, as the total number of damaging/degrading events that have occurred is not known.

Based on this assessment, there are several key factors for addressing damaging and degrading events. First, the wellbore events and conditions that can damage the wellbore sealing elastomers should be well documented and subsequently avoided. Second, if such an event occurs, it needs to be identified by the operators immediately. Lastly, once identified, a pressure test should be performed to determine whether the shock was of sufficient magnitude to cause fatal damage or observable degradation. In general, these factors are known to industry and they appear to do an acceptable job implementing them. However, as described in Section 2.2.2, guidance on these events is not as clear or refined as the requirements related to stump/installation pressure tests or time-based pressure tests.

Assuming correct identification of the degrading/damaging event occurs and a subsequent pressure test is performed, there appears to be minimal impact of changes to the time-based pressure test interval on elastomer reliability for this scenario.

Scenario 3: Elastomer Fatigue

The last scenario represents the vast majority of situations during offshore drilling, where the elastomers have successfully passed the stump and installation BOP pressure tests and have entered the time in standby on the wellhead. In addition, no atypical operational events or conditions occur that may degrade or damage the elastomers beyond the fatigue of the time-based pressure tests. There are several aspects that must be examined to determine the growth of PFD over time for such a scenario.

First, the probability of the elastomers failing on the next demand (PFD_{OD} or p) must be assessed. The value for PFD_{OD} is made of two primary components. The first factor is the initial PFD_{OD} when the elastomer enters service on the wellhead. This is an intrinsic property of the specific elastomer. Second, with each time-based pressure test, PFD_{OD} becomes larger due to cumulative fatigue damage. Although difficult, an attempt was made to estimate the initial value for PFD_{OD} and its subsequent fatigue growth with each time-based pressure test cycle.

The ideal approach to estimate the initial value for PFD_{OD} would be to determine how many elastomer failures have occurred during the first demand after a successful wellhead installation pressure test, then divide that value by the number of BOP well installations multiplied by the number of applicable components per well (such as annulars per BOP). However, such detailed failure information is not readily available. Therefore, a conservative approach was utilized here based on past data, as discussed below.

To estimate the initial value of PFD_{OD}, it was conservatively assumed that all recorded failures detected by the time-based pressure test and the pressure test after casing/liner were during the first demand after the wellhead installation pressure test. Failures detected by the stump/installation pressure test, by a pressure test after a degrading event, or during operations were not included, as these failures are likely the result of the other two failure mechanisms[43]. This estimate approach is considered conservative as all of the failures detected by the time-based pressure test and pressure test after casing/liner are being attributed to the initial value of PFD_{OD}, even though some of the failures may have been due to standby failures (PFD_{SB}), or failure during a demand at a later time after some growth in PFD_{OD} due to cumulative fatigue damage.

[43] Material defect/improper handling and installation, or a damaging/degrading event during operation.

The results of this estimation approach are presented in Table A - 17, and shown graphically in Figure A - 15 for annulars, and in Table A - 18 and Figure A - 16 for pipe rams and VBRs. As the results show, the past studies are fairly consistent in their findings, while there appears to be a slight decrease in failure probability in more recent years with the data from the current study.

Table A - 17: Annular – Initial PFD_{OD} Estimate

Study	*Failures during Time-Based PT or Casing/Liner PT*	*Approximate Number of PTs*[1]	*PFD_{OD}*[2]		
			Mean	*5th*	*95th*
SINTEF Phase II	*1*	*647*	*2.31E-03*	*2.72E-04*	*6.02E-03*
WEST	*Insufficient Information*[3]				
Exprosoft	*2*	*2,448*	*1.02E-03*	*2.34E-04*	*2.26E-03*
Total Past Studies	***3***	***3,095***	***1.13E-03***	***3.50E-04***	***2.27E-03***
Current Study	*13*	*~19,130*	*7.06E-04*	*4.22E-04*	*1.05E-03*

[1] Not including stump/installation PT, since BOP element cannot begin service until passing these PTs. The number was approximated by taking the total BOP service days divided by 11.5 (average number of service days between PT, as discussed in Section 2.2.2).
[2] Probability of wellbore sealing elastomer failure on demand.
[3] Data on BOP service days not provided.

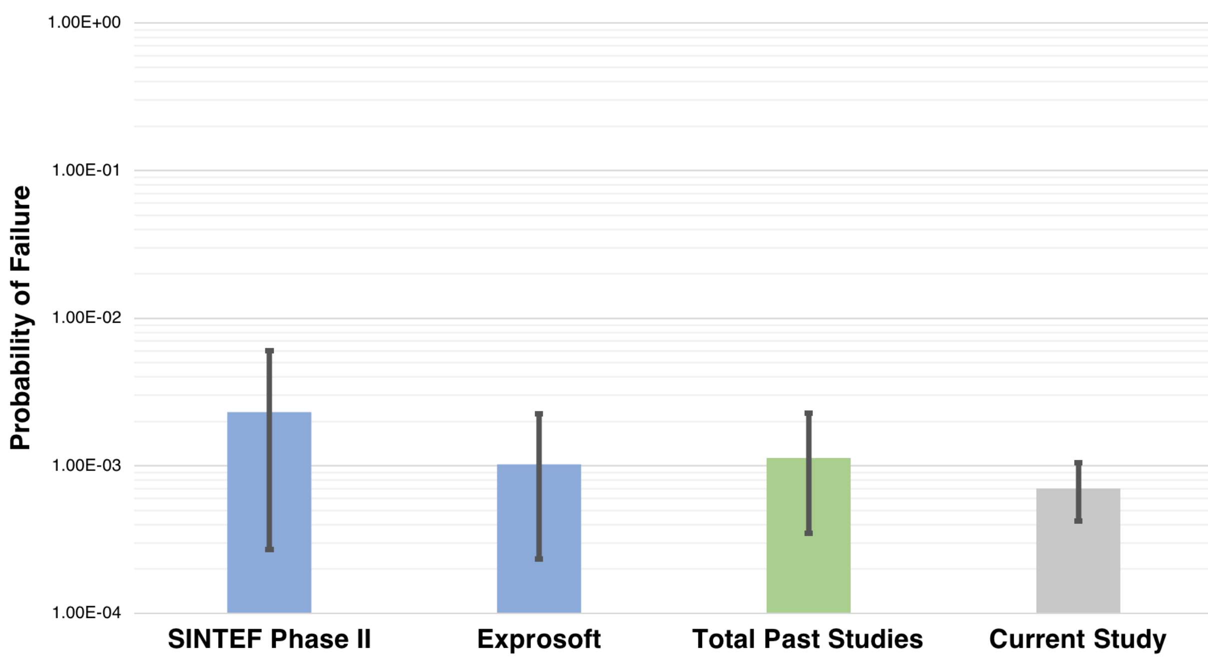


Figure A - 15: Annular – Initial PFD_{OD} Estimate

Table A - 18: Pipe Ram and VBR – Initial PFD_{OD} Estimate

Study	Failures during Time-Based or Casing/Liner PT	Approximate Number of PTs[1]	PFD_{OD}[2] Mean	5th	95th
SINTEF Phase II	2	1,408	1.77E-03	4.07E-04	3.93E-03
WEST	Insufficient Information				
Exprosoft	3	6,450	5.43E-04	1.68E-04	1.09E-03
Total Past Studies	**5**	**7,858**	**7.00E-04**	**2.91E-04**	**1.25E-03**
Current Study	6	~44,950	1.45E-04	6.55E-05	2.49E-04

[1] Not including stump/installation PT, since BOP element cannot begin service until passing these PTs. The number was approximated by taking the total BOP service days divided by 11.5 (average number of service days between PT).
[2] Probability of wellbore sealing elastomer failure on demand.
[3] Data on BOP service days not provided.

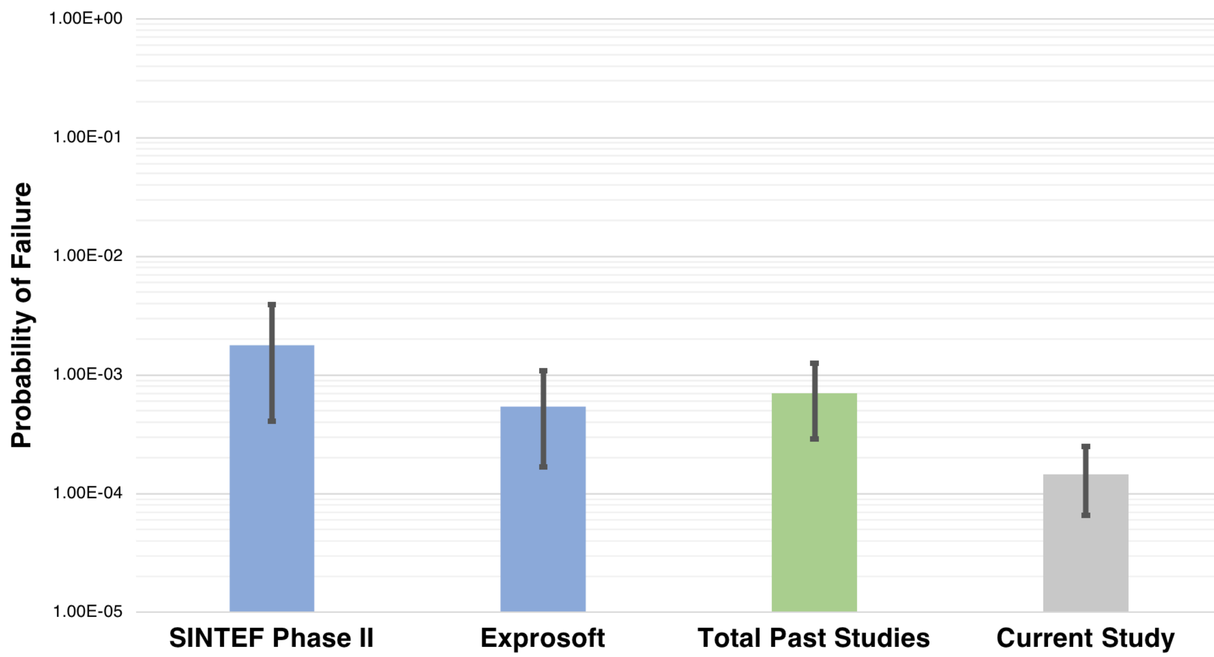


Figure A - 16: Pipe Ram and VBR – Initial PFD_{OD} Estimate

The next factor to determine is the increase in PFD_{OD} with each time-based pressure test. This is likely correlated to the cumulative damage from fatigue. Fatigue damage can be considered in a manner similar to the cumulative shock models discussed in Section E.1.4, where the damage from shocks accumulates with each event. Typically, the probability of failure from cumulative fatigue damage is based on the percentiles of the S-N curve[44] for a given stress level [37]. However, for the wellbore sealing elastomers, such detailed experimental data is not readily available. Therefore, an attempt was made to utilize the models for cumulative fatigue damage as a surrogate for the detailed S-N curve.

There are many models available to represent cumulative fatigue damage (see ref. [38]). Examples include the Palmgren-Miler's Rule (Linear Damage Rule – DLR) [39], Damage

[44] The S-N curve (S – stress, N – cycles) depicts the number of cycles until fatigue failure for a given stress level. It is constructed based on fatigue tests for a specific component or material.

Curve Approach (DCA) [40], the Double Linear Damage Rule (DLDR) [41], and the Double Damage Curve Approach (DDCA) [40]. In general, using these models directly as a substitute for failure probability results in excessively conservative values, especially at low cyclic ratios[45], as shown Figure A - 17, which compares the results of several popular models. Therefore, two different options were utilized for the current study, as a method to address uncertainty related to modeling cumulative fatigue damage for elastomers. First, the DCA model was chosen as the least conservative of the common cumulative damage models. The DCA model results in very low cumulative fatigue damage at low cycle ratios (<0.4), but increases quickly above cyclic ratios of 0.5. The second method chosen utilizes a standard log fit model (also shown in Figure A - 17), as it results in smaller failure probability values at cyclic ratios below 0.8. The log model is commonly used in cumulative shock modeling. The log model is likely a better fit for elastomer fatigue damage, as fatigue failures at low cyclic ratios appear to be rare.

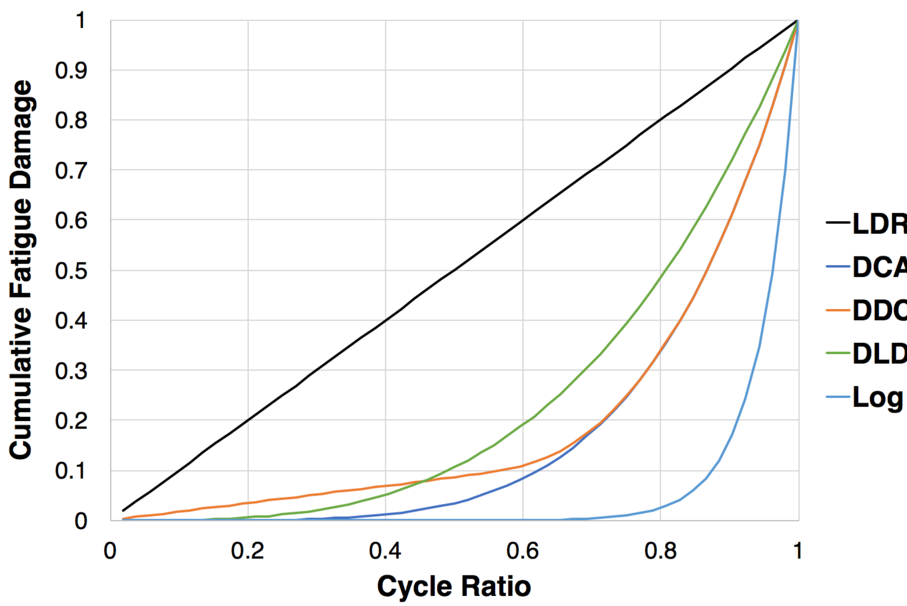


Figure A - 17: Comparison of Cumulative Fatigue Damage Models

In addition to PFD_{OD}, the standby failure probability PFD_{SB}, and particularly the standby failure rate (λ) also needs to be determined for the analysis. The standby failure rate was estimated here utilizing the failures that were identified during the time-based pressure test and the pressure test after casing/liner. It was conservatively assumed that all of these failures occurred during standby but were only identified during the pressure test. Failures detected by the stump/installation pressure test, by a pressure test after a degrading event, or during operations were not included, as these failures are likely the result of the other two failure mechanisms[46]. This estimate approach is considered conservative as all of the failures detected by the time-based pressure test and pressure test after casing/liner are being attributed to standby failure (PFD_{SB}). In reality, it is possible that some of these failures may have occurred

[45] The cyclic ratio is the number of cycles experienced divided by design life (cycles) of the component or material.

[46] Material defect/improper handling and installation, or a damaging/degrading event during operation.

during the pressure test demand and not during the time in standby. The amount of time in standby was determined based on the BOP service days.

Table A - 19 and Figure A - 18 present the standby failure rate (λ) estimate results for annulars. Again, the results appear to be fairly consistent across all studies, with likely a small decrease in recent data. Similar results for the pipe rams and VBRs is presented in Table A - 20 and Figure A - 19. As the results demonstrate, the standby failure rate for the annulars and rams appears to be quite small.

Table A - 19: Annular – λ Standby Failure Rate Estimate

Study	*Failures during Time-Based or Casing/Liner PT*	*Service (Standby) Days[1]*	*Failure Rate[2] (per day)*		
			Mean	*5th*	*95th*
SINTEF Phase II	*1*	*7,449*	*2.01E-04*	*2.36E-05*	*5.25E-04*
WEST	*Insufficient Information[3]*				
Exprosoft	*2*	*28,150*	*8.88E-05*	*2.03E-05*	*1.97E-05*
Total Past Studies	***3***	***35,599***	***9.83E-05***	***3.04E-05***	***1.98E-04***
Current Study	*13*	*~220,000[4]*	*6.14E-05*	*3.67E-05*	*9.12E-05*

[1] Service days taken from reports.
[2] Standby failure rate of the wellbore sealing elastomers.
[3] Data on BOP service days not provided.
[4] Estimated using average service days per well from past studies.

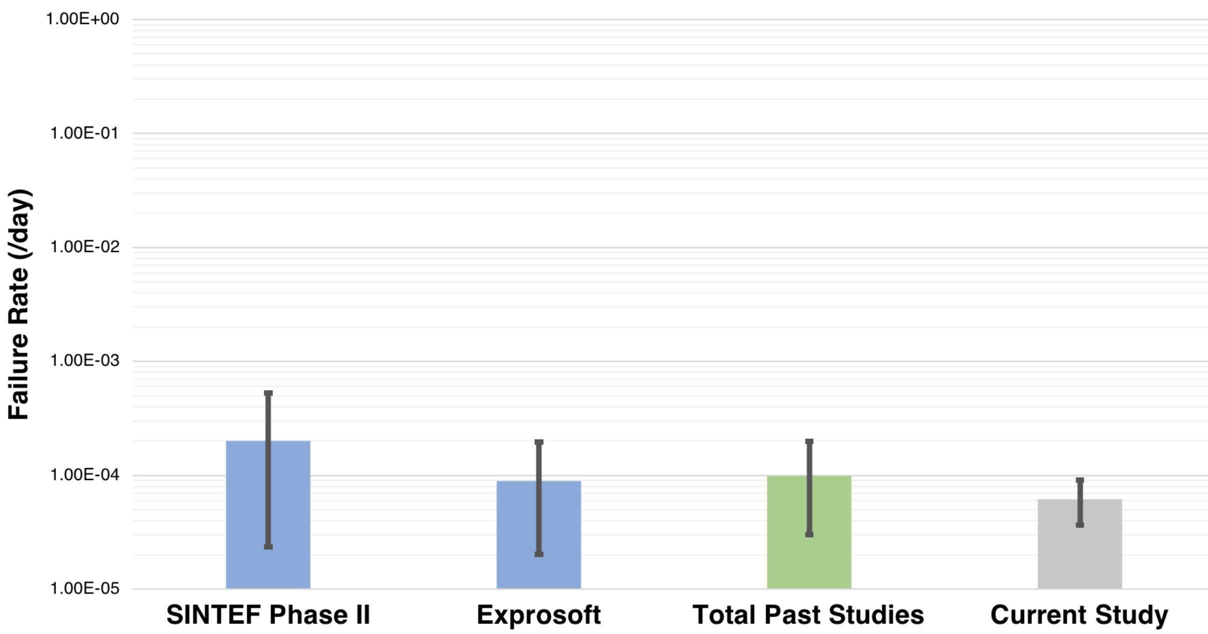


Figure A - 18: Annular – λ Standby Failure Rate

Table A - 20: Pipe Ram and VBR – λ Standby Failure Rate Estimate

Study	*Failures during Time-Based or Casing/Liner PT*	*Service (Standby) Days*[1]	*Failure Rate*[2] *(per day)*		
			Mean	*5th*	*95th*
SINTEF Phase II	*2*	*16,193*	*1.54E-04*	*3.54E-05*	*3.42E-04*
WEST	*Insufficient Information*[3]				
Exprosoft	*3*	*74,174*	*4.72E-05*	*1.46E-05*	*9.48E-05*
Total Past Studies	***5***	***90,367***	***6.09E-05***	***2.53E-05***	***1.09E-04***
Current Study	*6*	*~517,000*[4]	*1.26E-05*	*5.70E-06*	*2.16E-05*

[1] Service days taken from reports.
[2] Standby failure rate of the wellbore sealing elastomers.
[3] Data on BOP service days not provided.
[4] Estimated using average service days per well from past studies.

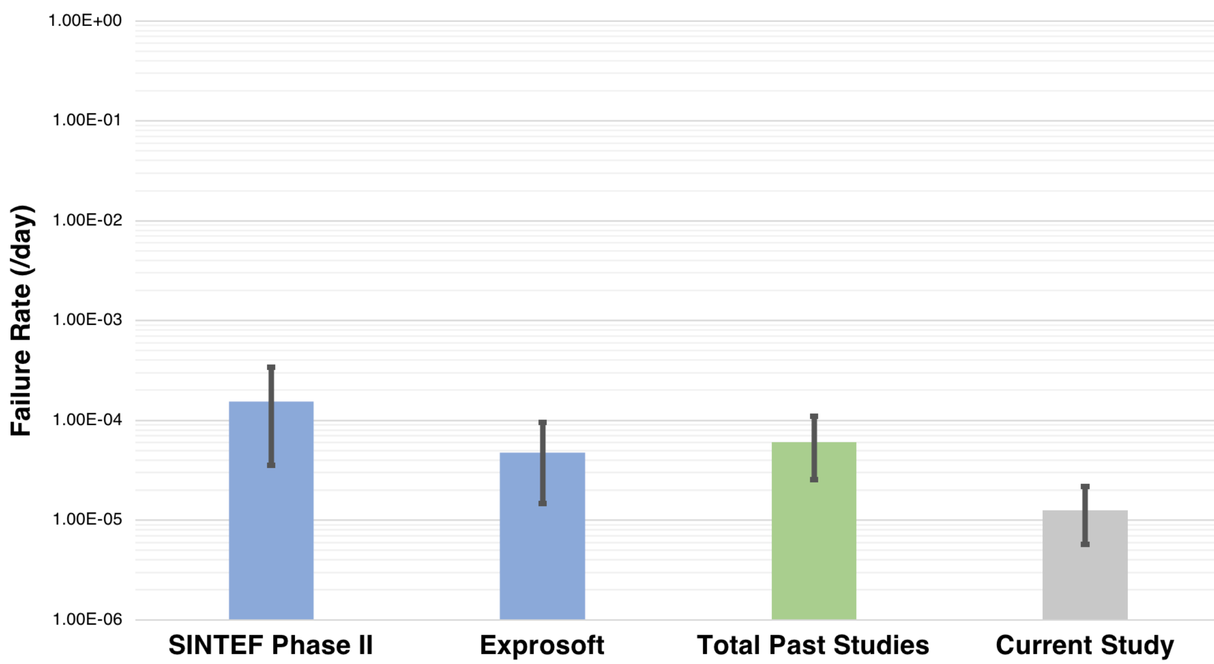


Figure A - 19: Pipe Ram and VBR – λ Standby Failure Rate

Taking the estimated values for PFD_{OD} and PFD_{SB}, an assessment could be made of the change in elastomer PFD_{TOT} over the lifetime of a well, including an evaluation of the impact due to changes of the time-based pressure testing interval. The analysis was performed utilizing the component reliability formula shown in Eq. 4.

Before viewing the analysis results, there are several important points to consider regarding the model assumptions, as documented in Table A - 21. First, the PFD was calculated for a 180-day well and assumes no pressure cycles of the BOP other than the time-based pressure test (and the initial stump/installation pressure tests). The total pressure cycle fatigue life for an elastomer is assumed to be 110% of the PR2 level requirement in the fourth edition in API 16A. While it is possible that elastomers may have longer fatigue lives, there are no quantitative requirements for such performance beyond the PR2 API 16A requirement.

Table A - 21: Elastomer Reliability Model Assumptions

Assumption
The calculated PFD is the probability of the wellbore sealing elastomers failing to isolate pressure when assuming a successful closure has already occurred
A 180-day wellhead connection is assumed
No elastomer replacement during 180 days
Only fatigue damage from pressure cycles is considered (not open/close cycles)
"Perfect" pressure testing intervals are assumed (e.g., exactly 14-day intervals)
Two pressure cycles have occurred before operation due to stump and installation pressure tests
No pressure cycles are included during operation other than those from the time-based pressure test
No additional stump/installation pressure tests due to the removal or repair of the BOP
No significant elastomer degradation event or wellbore condition during time on wellhead
Uncertainty due to differences in elastomer manufacturer or elastomer type (such as "long-life" units) is not explicitly considered
Fatigue life is assumed to be 110% of the API 16A PR2 fatigue minimum performance criteria (rounded to the nearest whole digit)
For cumulative fatigue damage, both the DCA and log-fit methods are considered through the model uncertainty analysis
Pressure tests assumed to be "complete" proof tests of the wellbore sealing elastomers
Model parameter estimates are based on the results from combined past study data, as there are uncertainties regarding the data from post-Macondo WAR data (see Section 4.2.3).

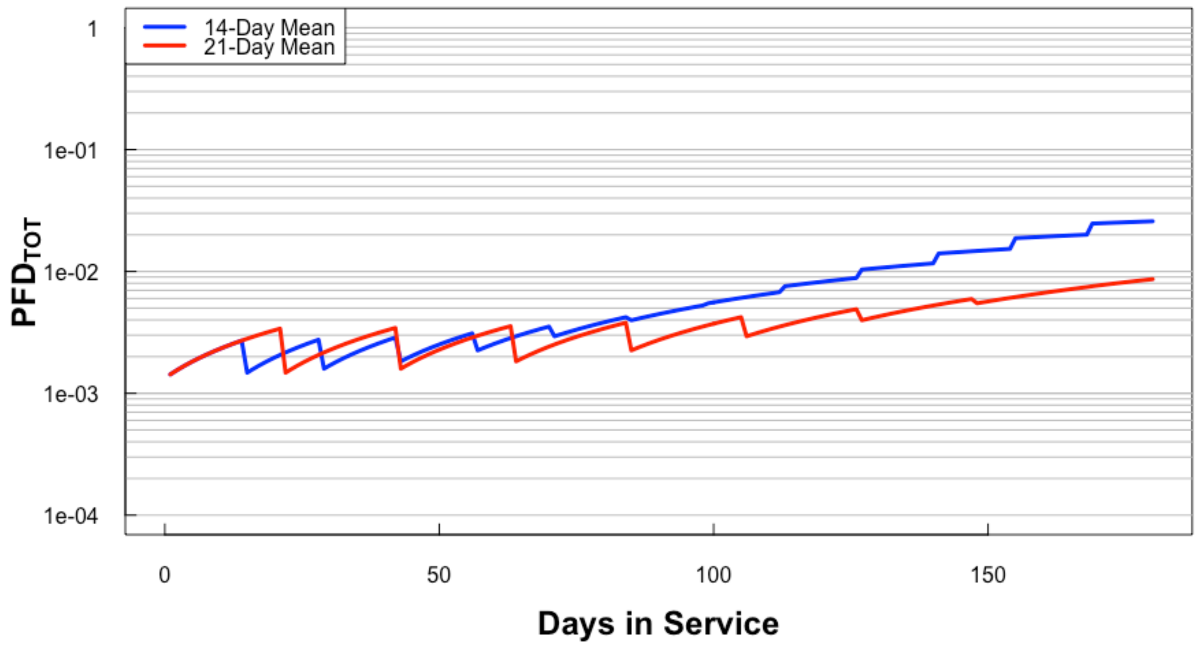
Annular elastomer reliability was examined first. Figure A - 20 presents a comparison of the elastomer PFD_{TOT} for a 14-day versus 21-day pressure testing interval for both the mean value and the uncertainty bounds (5^{th} and 95^{th} percentiles). As shown in the figure, although the 14-day pressure test yields a benefit (reduction in PFD_{TOT}) during the early period of the well, since it reduces the contribution from PFD_{SB}, the cumulative fatigue damage grows with each pressure test cycle. By the midway point of the time in service, the growth in cumulative fatigue damage is greater than the reduction in PFD_{SB}. Therefore, the pressure tests no longer reduce PFD_{TOT} but instead cause it to increase.

In comparison, due to fewer pressure test cycles, the 21-day pressure testing cycle exhibits a slower growth in cumulative fatigue damage. However, due to the extended time between pressure tests, a 21-day interval results in higher PFD_{TOT} values during the early period of the well. In general, the reduction in cumulative fatigue damage is greater than the increase due to the extended testing interval. This results in a lower average PFD_{TOT} valve for the 21-day testing interval, as shown in Table A - 22.

A similar comparison for a 14-day and 28-day pressure testing interval for the annulars is presented in Figure A - 21. In this case, the 28-day interval results in a much larger reduction in cumulative fatigue damage as there are half as many pressure cycles performed. There are higher peaks in PFD_{TOT} during the early portion of the well, as the time period between tests is twice as long, but this is more than compensated by the reduction in cumulative fatigue damage later in the well. As shown in Table A - 22, the 28-day testing interval actually results in the lowest average PFD_{TOT} of the three testing intervals.

Table A - 22: Annular – Testing Interval PFD Comparison

Time-Based PT Interval	*Average PFD_{TOT} (180 Days)*		
	Mean	***5^{th}***	***95^{th}***
14-Day	*7.86E-03*	*1.02E-03*	*1.49E-02*
21-Day	*3.90E-03*	*8.06E-04*	*7.34E-03*
28-Day	*3.33E-03*	*8.49E-04*	*6.25E-03*



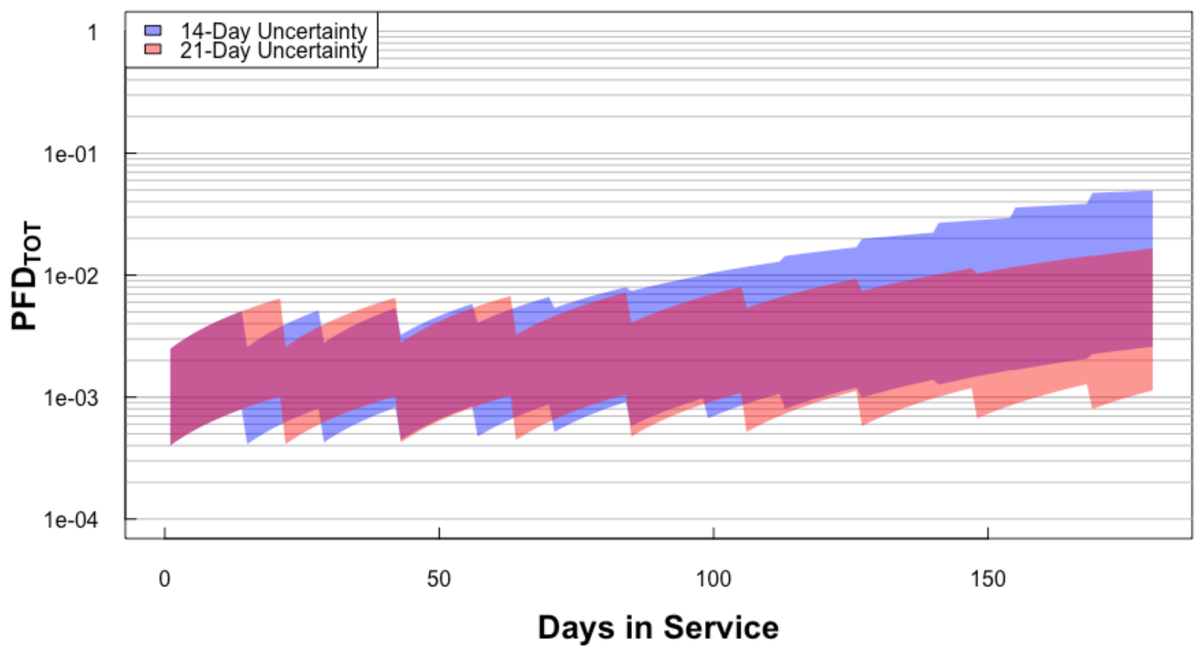


Figure A - 20: Annular – 14 vs. 21 Day Pressure Testing Interval PFD Comparison

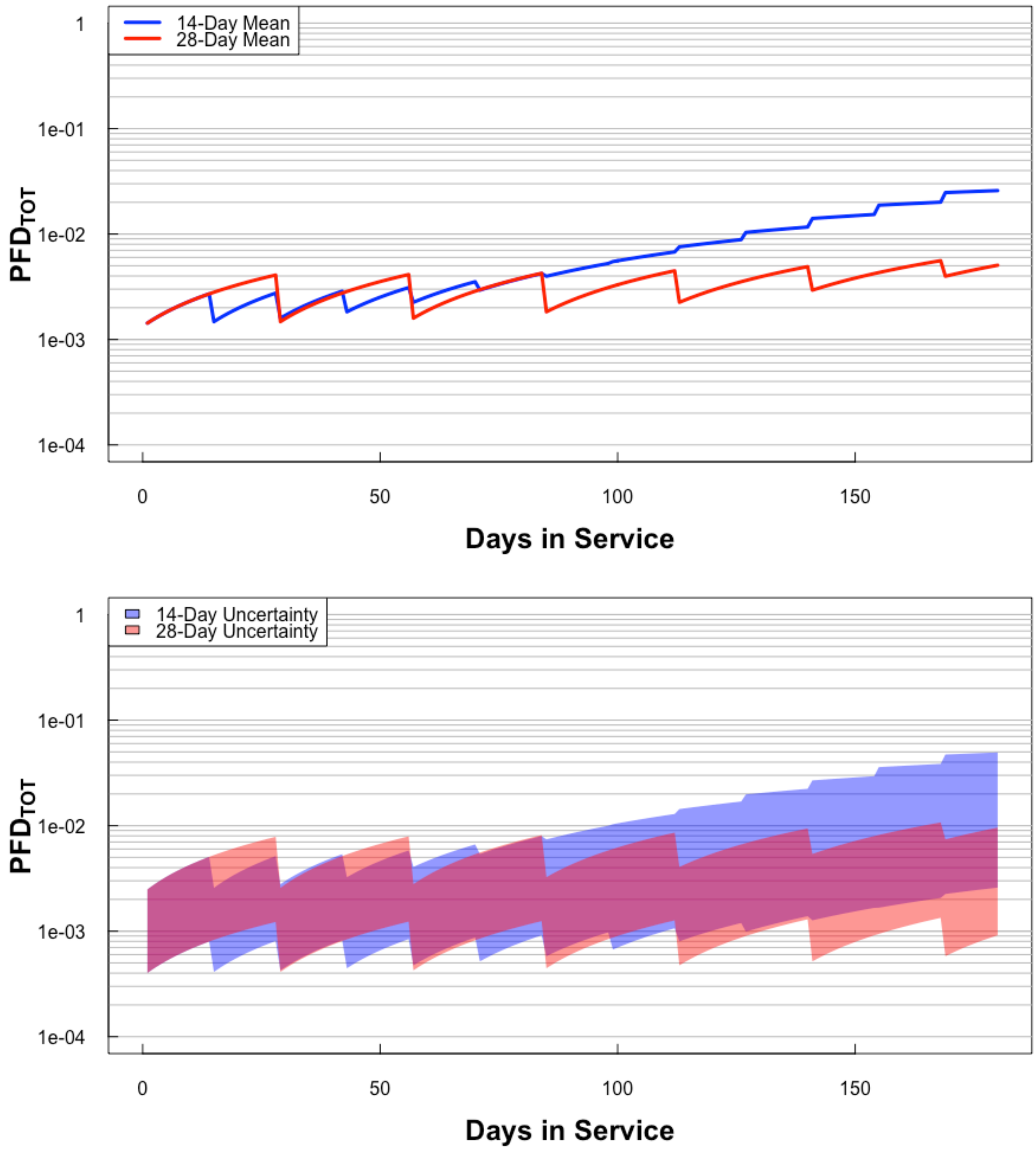


Figure A - 21: Annulars – 14 vs. 28 Day Pressure Testing Interval PFD Comparison

An equivalent analysis was performed for the pipe rams and VBRs, with the results shown in Figure A - 22, Figure A - 23, and Table A - 23. There are several main findings of the analysis. First, the PFD_{TOT} values appear to be lower than those for the annular. Second, in general, cumulative fatigue damage increases slower for the pipe rams and VBRs than with the annulars. This is due to the difference in the API 16A PR2 fatigue cycle requirements. For annulars, the standard has a minimum pressure cycle fatigue requirement of only 28 cycles, while it is 52 cycles for the pipe rams and VBRs. Therefore, utilizing the cumulative fatigue damage models described above, the cyclic ratio for the pipe rams and VBRs is much lower than the annulars. This results in a lower value of PFD_{OD} during this period.

As a result of the slower growth in cumulative fatigue damage, the value for PFD_{TOT} does not increase as dramatically near the latter portions of the time period as it does for the annulars. Therefore, the increase in PFD_{TOT} during the early period of the well from increasing the pressure testing interval is not offset to the same amount as it is with the annulars. As shown in Table A - 23, the 21-day and 28-day testing intervals have slightly higher average PFD_{TOT} values than the 14-day interval. However, the increase is small, with a 28-day testing interval resulting in an approximate 20% increase in the mean PFD_{TOT}, which is still within the margin of uncertainty for the 14-day interval result.

Table A - 23: Pipe Rams and VBRs – Testing Interval PFD Comparison

Time-Based	*Average PFD_{TOT} (180 Days)*		
PT Interval	*Mean*	*5th*	*95th*
14-Day	*1.34E-03*	*5.43E-04*	*2.23E-03*
21-Day	*1.45E-03*	*5.98E-04*	*2.45E-03*
28-Day	*1.64E-03*	*6.72E-04*	*2.78E-03*

The main finding of the analysis is that there is a balance between the growth in cumulative fatigue damage from the pressure tests and the reduction in standby failure due to conducting a test. If the fatigue damage from the pressure test is sufficiently greater than the standby failure rate, then extending the time-based pressure test interval will yield a reduction in PFD_{TOT}. However, if the standby failure rate is high and fatigue damage is low, then extending the time-based pressure test interval will increase the PFD_{TOT}. Based on the available data, it appears that the standby failure rate for the wellbore sealing elastomers is generally low when compared to the fatigue damage induced by each pressure test. Therefore, extending the time-based pressure test interval either results in a decrease in PFD_{TOT}, or only a small increase.

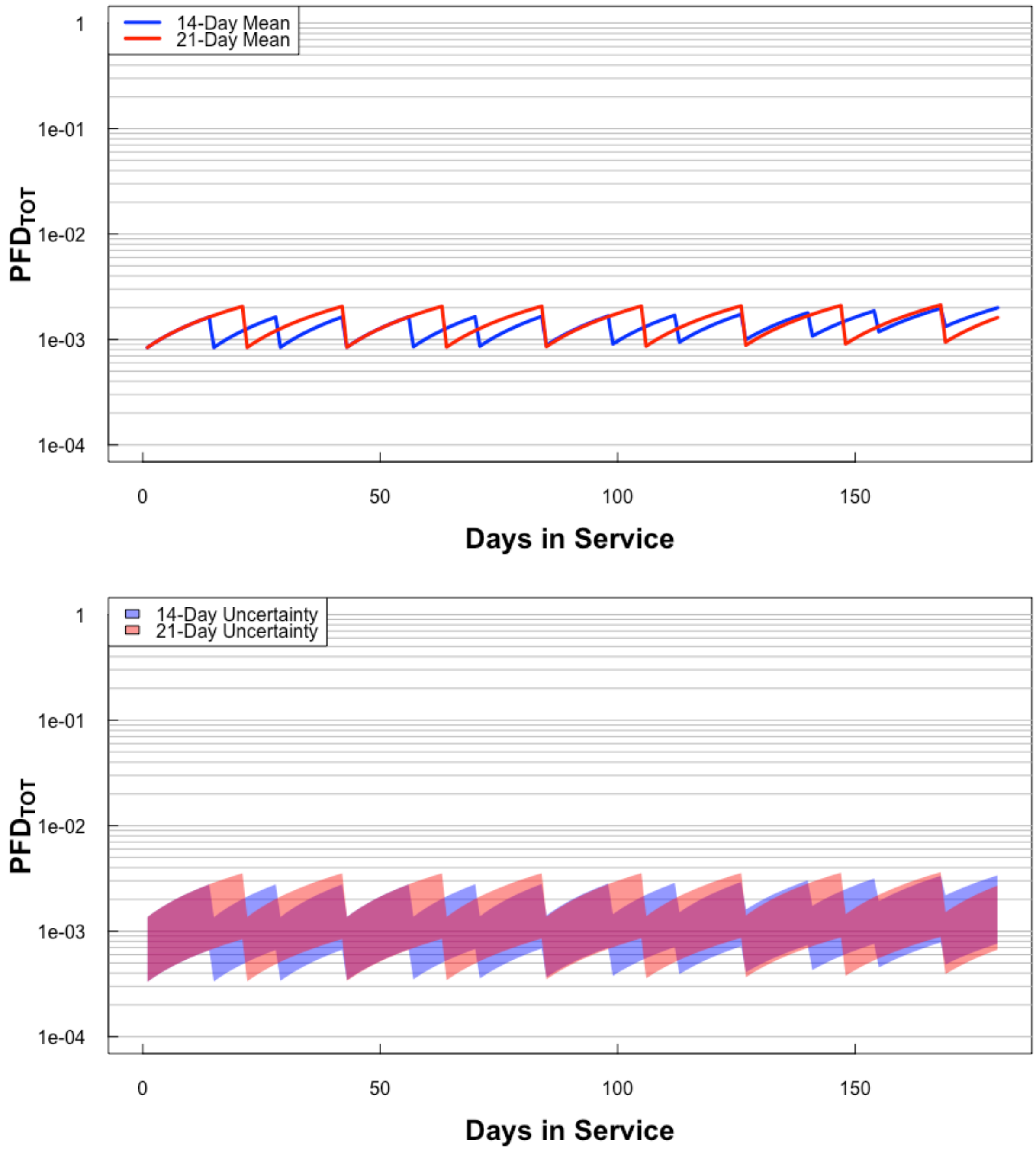


Figure A - 22: Pipe Ram and VBR – 14 vs 21 Day Pressure Testing Interval PFD Comparison

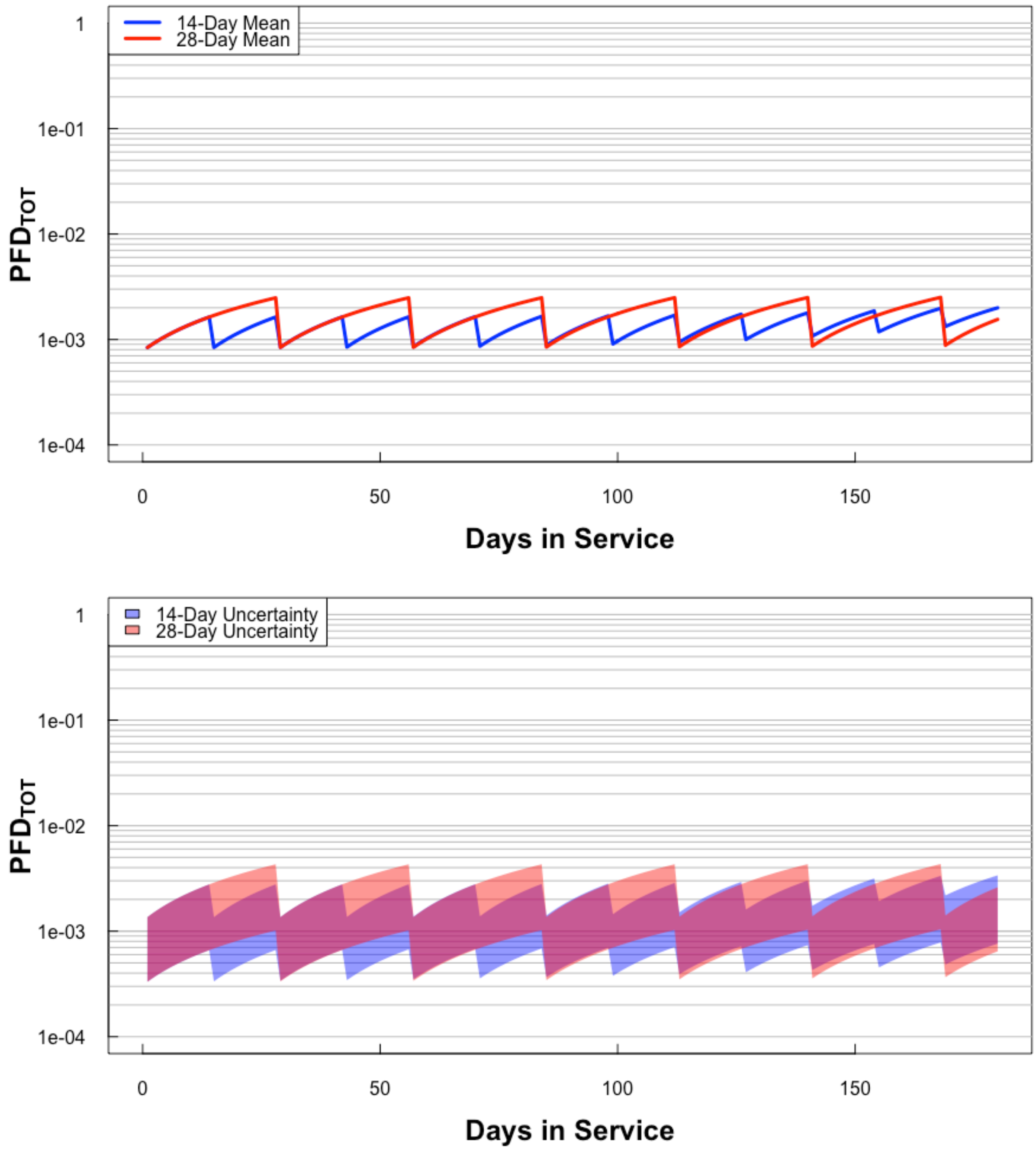


Figure A - 23: Pipe Ram and VBR – 14 vs 28 Day Pressure Testing Interval PFD Comparison

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