Case Study 2: Deepwater Drilling with Surface BOP from a Floating Facility

Submitted to
The Bureau of Safety and Environmental Enforcement (BSEE)

Submitted by
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September 2015

BPA Contract # E13PA00008
Task Order # E14PB00078
TDL #001, Deliverable D

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ABBREVIATION	EXPLANATION
BOP	Blowout Preventer
BSEE	Bureau of Safety and Environmental Enforcement
CCU	Central Control Unit
DP	Dynamic Positioning
DMAS	Deadman Autoshear Control System
DNV	Det Norske Veritas
EERA	Escape and Evacuation Risk Analysis
FDPSO	Floating, Drilling, Production, Storage and Offloading
FPSO	Floating, Production, Storage and Offloading
GoM	Gulf of Mexico
GOR	Gas to Oil Ratio
HAZID	Hazard Identification
HC	Hydrocarbons
HPU	Hydraulic Power Unit
HVAC	Heating, Ventilation, and Air Conditioning
LOEP	Loss of Electric Power
LOHP	Loss of Hydraulic Power
LQ	Living Quarter
MAH	Major Accident Hazard
MUX	Multiplex Control System
POCV	Pilot Operated Check Valve
ROV	Remote Operated Vehicle
SBOP	Surface BOP
SDS	Subsea Disconnect System
SPM	Sub Plate Mounted

1. Introduction

1.1 Background

As part of the Bureau of Safety and Environmental Enforcement (BSEE) Emergent Technologies project, our team developed a risk assessment framework to qualify new technology applications submitted to BSEE. To provide a better understanding of the risk assessment framework, ABSG Consulting Inc. (ABS Consulting) selected the following five scenarios to test the proposed framework. The results of the five risk assessment scenarios will guide BSEE during the review of new technology applications using the proposed methodology.

- Scenario 1: Ultra-deep water drilling
- Scenario 2: Deepwater Drilling with Surface BOP from a Floating Facility
- Scenario 3: Managed Pressure Drilling
- Scenario 4: Production in HPHT and Sour Environment
- Scenario 5: Drilling from a semi-sub in the Arctic

It is important to consider when reviewing this document, that the subject scenario background information and risk assessment were developed and tested based on publicly available information. Therefore, due to this limitation, the provided studies or assessments do not reflect real-life projects, and the studies performed for real-life projects will be more comprehensive than what we provide in this document.

This document provides information on Scenario 2: Floating production installations with a surface BOP.

2. Scenario Development

2.1 Scenario Description

The scenario considers drilling operations using a surface BOP in combination with a Subsea Disconnect System (SDS) in Gulf of Mexico (GoM) from a floating production unit with drilling capabilities.

Performing a drilling/work over operation using a surface BOP will introduce new challenges based on the site and the associated environment. The main function of the Blowout Preventer (BOP) is to contain the well during well control events such as a kick. An uncontrolled kick can potentially lead to a blowout scenario. This scenario will review the use of surface BOPs for well control and any additional risk created by its use; and associated barrier system functions.

To evaluate the scenario using the new technology risk assessment framework, consider a floating, drilling, production, storage and offloading vessel (FDPSO) equipped with a surface BOP. The subject floating production unit is moored permanently and will employ a surface BOP for drilling. It is designed for operations in environments as found in the Gulf of Mexico. Further details of the scenario characteristics can be found in the table below.

For this scenario, the following characteristics are considered:

Field Location	100 Miles offshore in the deep water Gulf of Mexico
Water Depth:	Approximately 4,000 ft.
Facility type	Floating Production Unit
Reservoir /Datum Depth (MD)	25,000 ft.
Reservoir /Datum Depth (TVD)	24,500 ft.
Bottom Hole Temperature	190 F
Wellhead flow temperature	170-200 F
Reservoir Pressure	12,000 – 14,000 PSIG
BOP Type	Surface BOP with subsea disconnect system
No. of development wells	15
Design Life	20 years
Rules and Regulation:	
Design and build using recognized classification rules SOLAS Other applicable rules and regulations.	

This chapter aims to present key information points on the type of operation covered in the assessment. It is imperative to note that not all the design basis information is included here; however, the new technology application submissions should include the following supporting documentation:

Engineering/Design Documents

- Design basis document providing the following information, but not limited to:
  - Design Life,
  - Operating Envelope,
  - Working Environment.
- Functional specification of all the major systems and associated interfaces.
- General arrangement/layout drawings.

The assessed scenario uses information that is publicly available and presented in such a way as to primarily illustrate the risk assessment methodology.

2.2 Technology Description

2.2.1 Purpose

This chapter will present, in detail, the SBOP system, the history behind it, current application worldwide, and differences compared to standard subsea BOP systems. The SBOP and the changes in risk following an application of it is the focus of this study, therefore this chapter includes the relevant background information for this.

2.2.2 Purpose of the New Technology or Application

As water depth increases, the weight of conventional risers increases to a point that only a very few fifth generation floating rigs have the capability to drill in ultra-deep water. With a surface BOP, it is possible to use a small diameter, high-pressure riser. This decreases the deck load requirements, reduces the volume of mud required[1], and eliminates the high choke line friction pressure experienced with conventional marine risers. This will allow older rigs to perform drilling operations at far greater water depths compared to when using a subsea BOP.

2.2.3 Current Situation of Where the Technology Is in Use

There has been work ongoing since 2003 on the use of surface BOPs in deepwater operations.

BSEE received several requests concerning the use of surface BOPs. However, the Code of Federal Regulations does not currently have specific requirements for SBOP. This is probably because there are no current wells in the GoM operating with surface BOPs in deep water.

Table 1 provides an overview of wells drilled with a surface BOP on the Mobile Offshore Drilling Units (MODUs), (see below).

[1] Compared to similar water depth with subsea BOP. Increased water depth could mean a total increase in mud required.

Table 1: Overview of Wells Drilled with a Surface BOP on the MODUs[2]

Location	No of Wells	Water Depth (ft.)	Water Depth (m)	Mooring System
Unocal Indonesia	66	70-3000	21 – 914	Pre-laid mooring
Chevron China	3	60	18	Taut mooring
Unocal Indonesia	45	< 6700	2042	Pre-laid mooring
Santos Indonesia	10	J-Up range		Pre-laid mooring
Deewoo Myanmar	3			Pre-laid mooring
Shell Malaysia	2	4500	1371	Pre-laid mooring
Unocal Indonesia	20	< 8000	2438	Pre-laid taut mooring
Shell Brazil & Egypt	4	< 9500	2895	DP (including subsea isolation device)

2.2.4 System/Technical/Operational Description

Figure 1 illustrates the main components in a surface BOP system. The Subsea Disconnect System, also known as the Subsea Isolation Device, is an integrated part of the BOP when it comes to risk and barrier assessment.

2 From 2014 offshore Technology conference Asia, «Surface BOP's Offshore Floaters", http://2014.otcasia.org/documents/14OTCA_PanelSession9GregNavarre.pdf

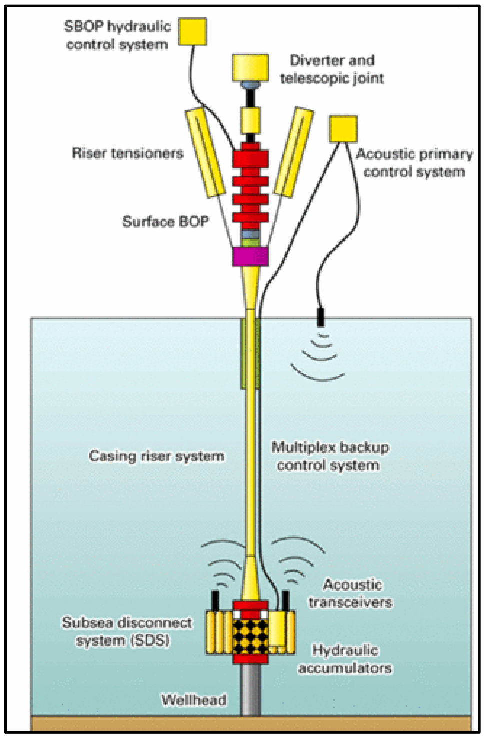

Figure 1. Surface BOP System (used on Stena Tay)[3]

Typical barriers that play a critical role are:

Blow out Preventer

- BOP acts as a last barrier between the surface facility and loss of well control. It contains the well fluids within the well bore.

Subsea Disconnect System

- Enables to disconnect the riser from wellhead during catastrophic event. Its function is to act as an emergency system not as a well control system.

2.2.5 Comparison of New Technology Versus Existing Solution (If Applicable)

Typically, a subsea BOP stack will have more rams compared to a surface BOP system resulting in increased redundancy of the subsea BOP when compared to a surface BOP. However, the surface BOP accessed from topsides allows for more frequent inspection, maintenance and testing, thereby increasing the availability of the system. The surface BOP also necessitates the use of a Subsea Disconnect System (SDS), which acts as an additional barrier for the surface BOP. In addition, the surface BOP requires smaller diameter, high-pressure risers.

[3] Illustration of Surface BOP used on Stena Tay; http://www.ogj.com/articles/print/volume-102/issue-17/special-report/surface-bop-technology-steps-into-deeper-water-with-dp-vessels.html

A key problem is whether a SBOP + SDS will provide an equivalent level of safety to a subsea BOP.

The design and testing requirements for Surface BOP stacks differ from those for a Subsea BOP, and are less stringent than those that are required for Subsea BOP. As noted in Chapter 6 and Chapter 7 of API 53 (Reference i). This is similar to the requirements of the Code of Federal Regulations and is a concern of regulators if deepwater applications use Surface BOPs.

Through the risk and barrier assessment, hazards associated with this system, changes in Major Accident Hazard (MAH) consequence, the key barrier critical system functions and related barrier element success criteria will be identified and analyzed in order to determine if a surface BOP used in deepwater operations provides an equivalent level of safety as a subsea BOP.

2.3 Risk and Barrier Assessment Workflow

The challenges found in deepwater and ultra-deepwater drilling have, in a remarkably short period, forced the oil industry to develop new technologies and techniques. The characteristics of the deepwater environments have pushed design criteria, normally used with onshore and shallow water wells, to values beyond their traditional limits.

The use of surface BOPs (from a floating facility) for offshore deepwater drilling is common in several parts of the world but there are smaller number of such instances in the Gulf of Mexico, where subsea BOPs are the norm. In general, the advantage of the surface BOP compared to the subsea BOP is the reduced cost. The SBOP arrangement greatly reduces the capacity requirement of the riser tensors enabling the use of cheaper rigs. The location of the SBOP just below the drill floor also provides easier access to equipment and reduces maintenance costs.

The SBOP system also offers advantages beyond being more economical. The SBOP system employs a casing riser, which reduces environmental loads and top tensions by more than 50%. Furthermore, the casing riser joints can be used as a traditional casing, which allows more frequent renewal of the riser, refreshing the fatigue life of the riser joints. Therefore, the discharge of drilling fluid from a riser failure reduces. Traditional offshore drilling systems use a flex-joint above the BOP, increasing riser wear due to flexible movements and motion. The SBOP system uses a stress joint in both extremities of the riser. In the SBOP system, the SDS installs over the wellhead. With this design, this equipment provides a redundant means to close the well, since the SBOP attaches to the system at the surface. The SDS closes even if a riser failure occurs.

One of the main disadvantages of the SBOP system is the need for a high-pressure riser. In addition, having high-pressure hydrocarbons (HC) right beneath the drill floor, which is the case when a kick has been shut in by the SBOP and not yet circulated out, creates some additional safety concerns. A Rig drift-off in such a situation is very risky and the reason why a dynamic positioning (DP) rig is not considered a realistic scenario.

Considering all the above aspects, the proposal of a surface BOP from a floating facility for deep water drilling is a suitable candidate for the new technology evaluation process. The workflow to follow within the new technology risk assessment framework depends on the novelty of the combination of the technology and the applied conditions, and an overview is presented in Figure 2. Hence, the scenario as described above represents technology, which is new to this environment. Thus, the assessment process should follow Workflow 3, i.e., new technology (surface BOP with SDS) in known conditions (GoM deepwater drilling).

The risk assessment will focus on the identification of MAHs and associated consequences. As part of the risk assessment, a review will need to be conducted to determine how the new technology can affect the existing barrier functions, both directly and indirectly, and any new interconnectivity to or from other barrier critical systems that the new technology is to work with in order for it to fulfill its intended barrier function(s). Operation of new technology for this environment would require a greater focus on the failure probabilities of the barriers for the identified MAHs. The subsea BOP would in this case be a natural benchmark for comparison.

An analysis to identify the critical success attributes for the barrier elements that constitute the barrier critical system is of extreme importance. The hazard identification (HAZID) carried out as part of the risk assessment helps in identifying the MAHs and affected barrier functions. The risk assessment for this scenario and related findings is in Section 3 of this report. The barrier analysis, which involves the review of a select barrier critical system to understand what needs to succeed in order for it to perform its barrier function, is in Section 4. For this purpose, a barrier model is developed and analyzed to determine the ways in which the barrier critical system can succeed as well as fail to perform its function. A good understanding of the success logic is critical in determining the requirements and related activities for ensuring the integrity of the barrier.

The application of the barrier model also provides insight about other barrier critical system(s)/barrier element(s) that interface with the proposed barrier critical system and contribute to the realization of the barrier function(s). The barrier model begins with the identification of the barrier function and contributing barrier critical systems. Next is identifying the required barrier critical system function(s) for each barrier critical system and the relevant barrier system elements. For each barrier element, the identification of physical and operational tasks enables the barrier critical system function. Performance influencing factors and attributes along with the relevant success criteria identify at this stage for the barrier element to perform its intended physical/operational tasks, thereby realizing the barrier function. For further detail, refer to for 1) Risk Assessment framework, refer to the “Risk Assessment framework for New Technologies in OCS”, and 2) Barrier Analysis, refer to the “Barrier Analysis for New Technologies in OCS”.

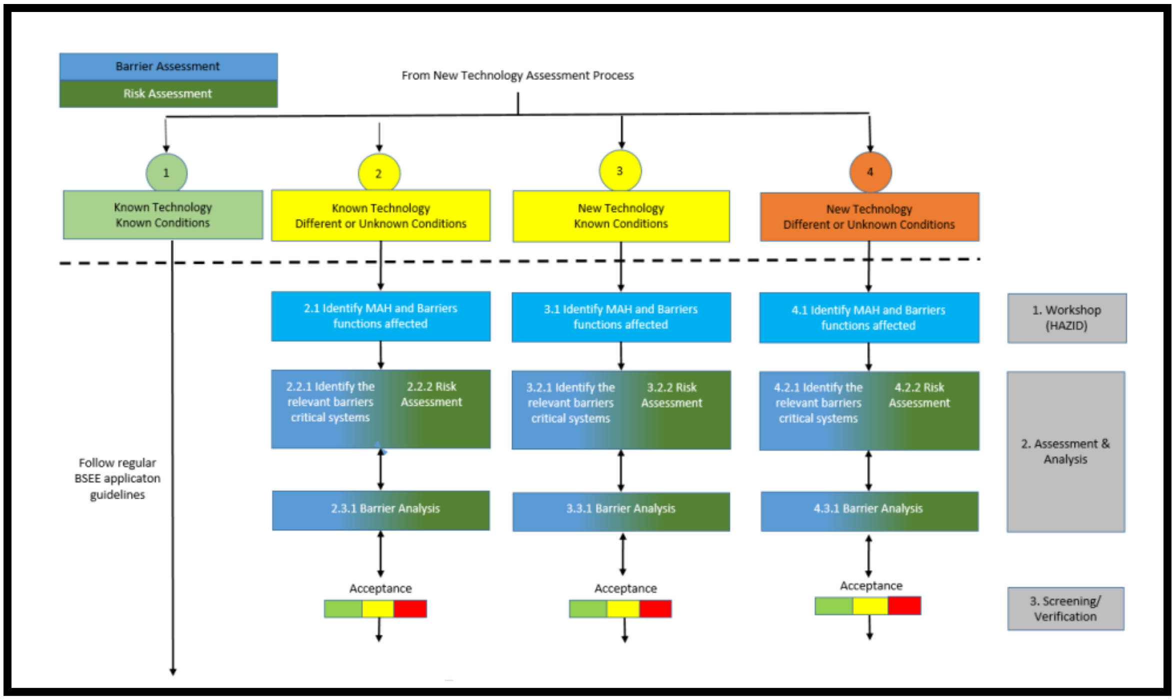

Figure 2. New Technology Assessment Framework

The Risk assessment will focus on the Major Accident Hazards and associated consequences. As part of the risk assessment, BSEE conducts a review to determine how the new technology can affect the existing barrier function, both directly and indirectly, and identify any new interconnectivity with or independence from other barrier critical systems that the new technology is to collaborate with in order for it to fulfill its intended barrier function(s).

Note the following from this chapter:

- Surface BOP systems are not completely new, and have been used in deepwater operations outside the GoM.
- A subsea BOP will be replaced by a surface BOP, mounted in the moonpool, and an SDS at the seabed.
- A surface BOP system (SBOP and SDS) will have fewer rams compared to a subsea BOP.

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3. Scenario Risk Assessment

3.1 HAZID

3.1.1 Purpose

As part of the Deepwater Operations Plan verification procedure, perform HAZID session. The HAZID aims to identify any impact on MAHs or barriers from new technology and/or changed conditions as identified in a pre-planning conference with BSEE. The focus is to identify any impact on barriers in place to control the actual MAH and possible changes in consequences from the same hazards.

3.1.2 General

This section documents the HAZID performed for the FDPSO with a SBOP in the GoM. The applied guidewords as well as the findings are within this section.

The following questions should be answered during the HAZID related to *New Conditions* and *New Technology*:

1. Do the <u>changed / new conditions</u> directly impair or weaken or increase demand on any barrier function(s) in place to control the MAH in question? Are any new barriers introduced?
2. Do the changed / new conditions give potential for increased or new consequences related to the MAH in question?
3. Does the new technology directly impair or weaken or increase demand on any barrier function(s) in place to control the MAH in question? Are any new barriers introduced?
4. Does the new technology give potential for increased or new consequences from the MAH in question?

3.1.3 Guidewords

During the HAZID, use the guidewords listed in Table 2 through Table 4 below. The relevance of each of the guidewords is in the session. Focus was on how the accidental events are affected by introduction of:

- Changed/new or unknown conditions,
- New technology.

As basis for the HAZID, a generic list of MAHs was established and is presented in Table 3. The HAZID procedure was applied to the FDPSO with SBOP looking to see if any changed/new conditions or new technology could cause one of these MAHs.

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Table 2: General Guidewords

General (Affected by Conditions / Technology)	Check List to Evaluate Any Major Accident Hazards
Loss of Evacuation and Escape	• Are escape and evacuation functions affected? • Are new escape/evacuation functions introduced?
Marine Operations	• Are marine operations are affected/introduced? • Collision hazards?
Marine / Other	• Anchoring /tethers/ DP • Loss of stability • Loss of buoyancy • Water depth • Environmental forces (wind/waves/cold/visibility) affecting operations? • Traffic surveillance/ control
Material Handling	• Is material handling affected? • Lifts over subsea equipment/pipelines performed? • Falling/ swinging load potential affected?
Other Events	• Helicopter crash • Power (main/emergency) • Blackout • Other?
Requirements	• Authorities • Standards • Deviations

Table 3: General Major Accident Hazards

Area Specific (Affected by Conditions / Technology)	Check List Used to Identify Major Accident Hazards Per Area

Major Accident Hazards (MAH) (Hydrocarbon)	• Loss of containment
	  ○ Process equipment
	  ○ Loss of well control
	• Ignition sources
	• Ventilation conditions
	• Ignition (fire/explosion):
	  ○ Process equipment
	  ○ Well (fire in shale shaker / mud system / DES)
	  ○ Engine room
	• Escalation potential (source/target)

Other Inflammable Materials and Fluids	• Methanol, diesel, lube oil, seal oil, hydraulic oil, glycol, electrical fires, etc. • Hot fluids • Cold fluids • Bottles (gas cylinders) with pressurized gas?
Toxic Gas / Other Effects	• Toxic releases • Anoxic effect • Hot / cold fluids • H_2S, N_2, CO_2, SO_2 etc. • Vents • Inerting systems • Hazardous atmospheres (CO, CO_2 etc.) • Biocide • Inhibitors (scale, corrosion) • Antifoam • Emulsion breaker • Oxygen Scavenger

Table 4: Area Specific Barriers

Area Specific (Affected by Conditions/ Technology)	Check List Used to Identify Barriers Area by Area
Fire and Explosion Barriers	• Are physical barriers (walls/decks) with respect to fire and explosion defined? (A/H – rated)
Escape Routes / Evacuation	• Are escape routes affected? • Has the area direct access to evacuation means?
Area Classification/ Heating, Ventilation, and Air Conditioning H(VAC)	• Are main principles for area classification established/affected? • HVAC - location of in/outlets and philosophy (actions upon gas exposure)?
Gas/ Fire Detection	• Is automatic gas and fire detection implemented in all relevant areas – need for more detectors? • Are the detectors suitable for detecting the hazardous substance(s), i.e., Methanol or Hydrogen Sulfide? • Alarms and/or automatic actions? • Voting principles and set levels?
Isolation and Blowdown	• Are segments isolatable by ESVs or XVs, also between main areas? (automatic/manual) • Are ESVs / BOP to be protected against fires and explosions? • Blowdown? (automatic/manual/time) • Flare or diverter system affected? • Power/signal dependency (fail safe?)
Active Fire Protection	• Is active fire suppression (deluge) to be implemented? • Philosophy for when deluge/monitors is released? • Fire water capacity (one or more areas simultaneously?) • Foam?
Passive Fire Protection	• Philosophy? • On structural elements? • On process equipment? • On main safety critical elements (e.g. RESVs etc.)? • On risers/riser tensioning system? • On flare system/stack?
Other Barriers	• Emergency power affected? • Drain affected? • Heat tracing – on what barriers?

3.1.4 General Guidewords

ID No	Guideword	Hazard/Accident	Existing Risk Reducing Measures	Observations	Action/Recommendation
1.1	Loss of Evacuation and Escape	Loss of Evacuation and Escape	Surface BOP and SDS	Escape and evacuation will in general be affected the same way. The function is not changed, but it depends on how fast the drill string may be cut; how fast the drill string is cut will affect the potential magnitude of the release. Since this is an anchored FDPSO, there is no realistic way of performing a move-off maneuver.	Verify how fast the disconnect function (i.e., subsea shear ram) can be achieved. Reliability of system to be assessed.
1.2	Marine/Other	Loss of Buoyancy	Ballast System/Anchoring	An extreme event resulting in the FDPSO losing position will result in the SDS performing automatic cutting of the riser. For an anchored installation, the SDS will normally be equipped with one shear ram and one pipe ram, contrary to two shear rams for a DP vessel.	Ensure proper dimensioning of the rig for the relevant environmental conditions.
1.3	Material Handling	Dropped Objects	Material Handling Plan and Exclusion Zones	The use of smaller diameter risers will mean a lower requirement of mud; however the greater water depth may result in the need for more mud. Contrary to a subsea BOP at the same water depth, the mud requirement for an SBOP is lower. This will affect the amount of required material handling.	Info
1.4	Material Handling	Dropped Objects		Lifting will be performed in the derrick above the SBOP, a drop could result in critical damage.	Need to investigate if there is any protection installed for this.
1.5	Marine Operations	Collisions	Traffic Surveillance	Collision risk should not be adversely affected by the BOP design, and should be the same (or lower) as for a subsea BOP. Worst case scenario resulting in loss of entire FDPSO due to ship collision will result in the SDS shearing the riser and sealing in the well (See point 1.2).	Info
1.6	Material Handling	Dropped Objects	Material Handling Plan and Exclusion Zones	The BOP does not have to be lifted to topside, hence there are fewer heavy lifts.	Info
1.7	Requirements	Loss of Well Control		The casing is important here. Must be classified for high pressure.	Will require classification/testing of casing. Has been addressed as a challenge.
1.8	Other	Drop of Stack	The surface BOP stack is suspended using the riser tensioning system.	A fault in the tensioning system could lead to a drop of the entire stack, this could further lead to loss of containment.	Should verify the redundancy of the tensioning system. Sudden loss of one or more wires may result in 'tug' on the other wires, need to verify that system can withstand this. Should investigate how the system reacts to loss of the BOP in this manner; i.e., loss of SBOP and/or buckling of riser

3.1.5 Area Specific Accidental Events

ID No	Guideword	Hazard/Accident	Existing Risk Reducing Measures	Observations	Action/Recommendation
1.9	MAH Hydrocarbons	Unable to Shear Due to Blackout	Multiplex backup control system. The principle should be the same as for a subsea BOP. SDS shear ram should not be affected by a blackout. Hydraulic Accumulator for SDS shear ram.	The system may be less redundant since it is not known how many 'tries' for cutting riser the accumulator is designed for. SDS usually not able to cut casing or tool joint. Dead-man-system common for SDS; i.e., loss of power and hydraulics will cause the SDS to shut in the well.	The functionality/control of SDS shear ram to be assessed/analyzed. May have to resort to backup measure – ROV – to close in the well. Define the manual options to initiate the SDS
1.10	MAH Hydrocarbons	Unable to Shear	-	The shear ram system (subsea) is different compared to a subsea BOP and may have different reliability compared to a traditional system. The shear ram on the SDS is identical to what can be found on a subsea BOP. SBOP has the flexibility of being able to use either SBOP ram or SDS ram.	A comparison with a subsea BOP, with respect to the reliability of the shear ram system should be done.
1.11	MAH Hydrocarbons	Unable to Shear	-	The SDS shearing system should be able to shear drill pipe and seal the well. SDS is usually not able to shear casing; any tool joints will also have to be moved in order to shear the riser. The SDS and the SBOP will usually be placed such that one may be used; i.e., in the case of a tool joint blocking one of the shear rams, the other will be free. If the BOP shears the riser, there will be pressure in the riser up to the FDPSO.	Verify that the SDS will cut drill pipe as well as seal the well. Also, the shear/seal capabilities of the surface BOP must be addressed. Check ability to circulate if the SBOP shear the riser (pressure up to FDPSO).
1.12	MAH Hydrocarbons	Unable to Shear	-	Given an external leakage from the riser, the only possibility is to shear subsea as the BOP is topside. I.e. closing the BOP topside will lead to gas leaking out of the riser and exposing the topside.	Amount of gas in riser should be assessed. Also identify where gas will leak out.
1.13	Other Inflammable Materials and Fluids	Release of Other Inflammable Materials and Fluids	Containment of inflammable materials (tanks, vessels, piping)	There are less hydraulic lines due to the BOP being located at surface.	Info
1.14	MAH Hydrocarbons	Loss of Well Control	-	Testing and maintenance of SBOP is much easier; also the SBOP does not have to be lifted topside for maintenance. This will generally increase the reliability of the SBOP. Conversely, poor maintenance and increased handling (as for subsea BOP) could mean a decreased reliability.	Info

ID No	Guideword	Hazard/Accident	Existing Risk Reducing Measures	Observations	Action/Recommendation
1.15	MAH Hydrocarbons	Loss of Well Control	-	Typically a subsea BOP stack will have more rams compared to a Surface BOP system resulting in increased redundancy of the subsea BOP when compared to a surface BOP. ; i.e., the redundancy of the SBOP is lower compared to that of the subsea BOP. However the surface BOP can be accessed from topsides allowing for more frequent inspection, maintenance and testing, thereby increasing the availability reliability of the system	Verify if this influences on flexibility for mud circulation.
1.16	MAH Hydrocarbons	Loss of Well Control	-	Pressure class of material may be less as the BOP can be topside. Conventional type of BOP as for fixed installations with BOP topside.	Requirements to be checked
1.17	MAH Hydrocarbons	Loss of Well Control Due to Dropped Objects	-	When the BOP is topside, there is more potential for damage due to e.g. dropped objects. Especially for lifts in the derrick directly above the SBOP. See point 1.4.	Conduct dropped object and material handling study to ensure appropriate protections are provided
1.18	MAH Hydrocarbons	Loss of Well Control Due to Incorrect Operation	-	Easier accessibility to BOP will lead to higher potential for incorrect operation.	Info
1.19	Other	Tank Explosion	Maintenance of non-combustible atmosphere in Floating, Production, Storage, and Offloading (FPSO) storage tanks required per procedure.	Explosion in the storage tanks of the FPSO, or pump room, is expected to have a very serious consequence leading to massive damage. This could mean loss of the SBOP and further loss of containment in the well. A subsea BOP will in this case have more rams and thus a better possibility of sealing the well.	The consequences of such extreme incidents should be investigated.

3.1.6 Area Specific Barriers

ID No	Guideword	Hazard/Accident	Existing Risk Reducing Measures	Observations	Action/Recommendation
1.20	Area Classification	Change in Technology Causing Necessary Re-classification	-	No change as derrick already is classified.	Info
1.21	Escape Routes / Evacuation	Potential Blockage of Escape Routes Due To New Equipment.	-	Topside BOP will need space. Potential effect on escape ways. With the use of surface BOP, the area around the SBOP will be restricted area and will require permit to work to enter the area.	Escape routes / evacuation must be classified for new leak sources (i.e., BOP) where there didn't used to be.
1.22	Isolation and Blowdown	Blowout Causing Use of BOP and Shear Ram	It will be possible to shear at the top (at BOP) as well.	After shearing and closing BOP, there will be a riser with HC (at potentially high pressure) down to shearing point.	Needs to be covered in risk and barrier assessment.
1.23	Gas/Fire Detection	Blowout Exposing Topside from Subsea Release or from Release near BOP.	Gas detection in derrick and at HVAC inlets on FDPSO.	Historical data show that there might be issues with the connector between the wellhead and BOP for subsea BOPs. Now there will be a connector topside. A kick may come out right under the rig instead of at the sea floor.	Integrity of the connector must be checked. Potential for large subsea releases (from casing) to be assessed with respect to functionality of gas detection system
1.24	Gas/Fire Detection	Blowout Exposing Topside from Subsea Release or from Release near BOP.	Gas detection in derrick and at HVAC inlets on FDPSO.	-	Due to more leak points, it should be checked whether gas/fire detection should be upgraded.
1.25	Choke and Kill System	Blowout	-	Choke and kill systems are simpler on surface BOPs which gives less redundancy. On subsea BOPs there will usually be two lines for each.	Reliability / functionality of choke and kill systems to be assessed.
1.26	Active Fire Protection	Ignited Well Events	Deluge and water monitors	Area with BOP will have to be protected by fire deluge/ monitors. Initially smaller fire could expose tensioning system resulting in drop of BOP stack. Additionally, fires in other areas could escalate to the BOP stack or tensioning system.	Conduct fire risk analysis that consider the topsides BOP events to ensure that appropriate active/passive fire protection is provided
1.27	Choke and Kill System	Blowout	There are systems for this on producing installations with topside BOPs	If the entire well is shut off with a subsea BOP, you can circulate with choke and kill. There will probably be more kill mud needed with a surface BOP.	
1.28	Isolation and Blowdown	Blowout	BOP and diverter system	Diverter system may have to handle larger amount of gas/HC. Important to monitor pressure in shut in riser. The increased amount of gas refers to the volume above the SDS.	There must be focus on pressure monitoring. Similar issues will have been faced on fixed installations with surface BOPs, Review lessons learned from the surface BOP on fixed installations.
1.29	Kill and Choke	Blowout	BOP and shear ram subsea	After shearing with the SDS, there might be more issues	It must be checked whether there is more potential for issues

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ID No	Guideword	Hazard/Accident	Existing Risk Reducing Measures	Observations	Action/Recommendation
	System			related to well control after the event. On subsea BOP, can circulate with kill and choke lines after the fact.	after an event.
1.30	Pressure Monitoring	Blowout	BOP and shear ram subsea	To have control of the pressure in well amount of HC shut in - pressure monitoring at wellhead must be addressed.	Must be checked how pressure is measured in closed-in well.
1.31	Isolation and Blowdown	Blowout	BOP and shear ram subsea	There is less redundancy on closing the stack. Due to higher reliability for the surface BOP, less redundancy is inherently established.	Needs to be covered in barrier assessment.

3.1.7 Summary of HAZID Findings

The following is a summary of the findings from the HAZID.

3.1.7.1 General Guidewords

Most external causes will not be significantly affected when using a SBOP versus a subsea BOP. The exception, as found in the HAZID, is the possible exposure of the SBOP to dropped objects (drill pipes/riser) in the derrick. Escape and evacuation means will not be directly affected; however, changes in the consequences of unwanted events will affect impairment of these. Possible effects of marine events (loss of buoyancy, anchoring etc.) are not expected to have any significant impact; however, this will be verified in the following section of detailed risk assessment.

3.1.7.2 Area Specific Accidental Events

There will be less hydraulic lines for an SBOP, and generally believed to have lower volume requirements for mud. This reduces the amount of other liquids.

Dimensioning the capability of the rams has been discussed; it needs to be verified that the rams are able to cut casing/riser and seal the well. For risk assessment purposes, this will need to be evaluated. The effect could be a delay in the time required to seal the well and possibly not properly sealing the well, leading to a smaller release (i.e., a well release as opposed to blowout) or not being able to seal the well at all. Proper functionality of the SDS also needs to be verified. This is especially important in scenarios where a topside accidental event has led to impairment of the SBOP leaving the SDS as the only means of sealing the well.

Leakage location has been discussed. A leakage in the riser (between SDS and BOP) will require activation via SDS to stop the release. If this fails, and the release point is near the sea surface, the release could threaten platform safety. Proper pressure testing and classification of the riser ensures that the riser is designed sufficiently.

There is less redundancy in the SBOP; the background for this is in part the easier accessibility of the unit increasing its reliability.

3.1.7.3 Area Specific Barriers

There might an increased need for fire protection in the derrick; verification of detector layout in the derrick and increased active fire protection (deluge/fire monitors). Possible escalation of an ignited event to other segments and out of derrick needs to be addressed.

Pressure monitoring is important. If the riser is cut at the SBOP, the riser will remain pressurized down to the seabed. If the SDS is used, the volume of hydrocarbon is contained in the well. Pressure control at the wellhead is mentioned. Applicability of the choke and kill system to circulate the well should be verified.

This chapter has presented details from the HAZID. The following hazards are found that might require special attention:

- Dropped objects within the derrick possibly impacting the SBOP.
- Shutting in the well using the SBOP will leave the drilling riser pressurized from the seabed to the FDPSO.
- Scenarios where the SDS is the final barrier towards loss of well containment is critical; e.g. leakage in the drilling riser.

It is also important to note from this section that the HAZID is the basis for defining the list of studies that should be performed in the risk assessment (Table 5).

Hazards not mentioned here have been found not relevant in the HAZID, and will not be analyzed further.

3.1.8 Detailed Risk Assessment Work

3.1.8.1 Purpose

This section will give brief overview of the suggested studies based on the results from the HAZID. Details on the studies will be further elaborated on in the risk assessment in Section 3.2.

3.1.8.2 General

Hazard identification is the first step in the risk assessment process. Much of the value of the hazard identification process comes from being able to better understand the effects of the initiating events and the consequences for the impacted areas on the overall risk. As part of a general application, a risk assessment is provided to give a description of the risk inherit to the operation. For the current application, consider two important points when conducting the risk assessment:

- Focus on the total risk picture of the operation.
- Focus on the difference between using a conventional BOP and using a surface BOP.

The size of the study will also take part in deciding the detail level of each study. For a larger study, a full Computational Fluid Dynamics (CFD) approach can be taken when assessing the consequences and possibly a complete quantitative analysis of the entire installation can be made. For smaller studies, the detail level will be reduced, and more focus is put on the critical components. In this case, that would be the SBOP and accidental events connected to it.

The following events can contribute towards the total risk picture of the operation:

- Loss of Containment Events,
- Structural Events,
- Other events.

The following section provides detailed information on each of the above-mentioned events.

3.1.8.3 Loss of Containment Events

Loss of containment of hydrocarbons event may lead to:

- Toxic exposure of personnel.
- Ignited events exposing personnel to fire and/or explosion loads.
- Ignited events exposing the structure to heat loads possibly impairing the structure.
- Release of hydrocarbons to the environment with subsequent environmental consequences.

Many scenarios can lead to loss of containment scenarios, with many different underlying causes. The following studies will cover these initiating events:

- Process release study,
- Well event release study,
- Riser release risk study,
- Other release study (diesel or other dangerous chemicals).

The process release study will cover the risk contribution from process equipment on the FDPSO. The frequency basis will be derived from the extent of the process area, i.e., the number of potential leakage points. By applying applicable process conditions, it is possible to estimate durations of the different scenarios that may be further used in the consequence analysis. The HAZID identified possible escalation of initial process accidents; this will be covered in this analysis in combination with the consequence analysis.

A well event release study will cover all loss of containment scenarios related to the well; i.e., blowouts and well releases. The frequency basis is taken from specified data sources and applied for the FDPSO in combination with the drilling schedule and number of wells to estimate release frequencies valid for the FDPSO in question. In the HAZID, the possibility of more leakage points (the SBOP itself or the riser between the SDS and the SBOP) was discussed. This will be included in the well event analysis.

Finally the riser release study will examine the riser configuration and based on historical data, estimate an annual frequency of such events. The dimensions of the riser along with flow medium and process conditions can be used to estimate release sizes and durations.

Other release studies will most likely have a relatively low risk contribution; examples are diesel spray from generator or chemical spills. Another example of other loss of containment incidents is explosions in the cargo tanks or pump room. These are rare incidents (none registered for FDPSOs, significant amount for tanker vessels) with very severe consequences. Such an explosion could result in severe structural impairment of the hull; further, this could also affect the SBOP and in turn lead to loss of containment of the well. Due to this severe consequence, we recommend to include a study on this in the overall risk assessment. Focus will be on the consequences of such an event and on possible risk mitigations as well.

3.1.8.4 Structural Events

Structural events are events that directly threaten the structural integrity of the FDPSO, or parts of it, that do not involve hydrocarbons. Examples are:

- Ship Collision,
- Dropped Objects,
- Environmental Impact,
- Fatigue/Material Weakening.

A ship collision analysis will give an overview of the risk contribution from collisions with passing or visiting vessels. A ship collision from a sailing vessel will result in a high-energy impact (dependent on size of vessel and impact speed). This could result in structural damage to the FDPSO, but likely not sufficient damage to lead to total impairment. If the vessel strikes near the riser connection area, this could lead to a loss of containment scenario. Impact could result in damage to personnel and will most likely lead to significant damage requiring repair. It is not expected that the use of a SBOP on the FPSO will have any effect on the resulting consequences of a ship collision.

Dropped objects can have severe consequences like direct impact on personnel or impacts leading to loss of containment. A drop inside the derrick could affect the SBOP, which in turn could lead to a loss of containment situation. A dropped object risk analysis will give an overview of the inherit risk contribution from potentially damaging the SBOP and suggest proper risk mitigating measures that can be applied.

Environmental impact covers impact from wind and waves, as well as earthquakes. These incidents will vary greatly based on the location of the FPSO. Some regions are prone to significant amounts of bad weather while others are sufficiently sheltered such that the risk contribution is negligible. The use of SBOP has generally been reliant on calm seas; therefore, such an analysis could provide information on the inherit risk contribution of an SBOP exposed to harsh conditions as well as suggest risk mitigating measures.

Fatigue or material weakening could lead to loss of important structural elements and in turn severe consequences based on which elements are impaired. Weakening in the anchoring system could lead stability issues; impairments in the riser tensioning system could lead to loss of the SBOP; or poorly designed elements, for example risers used when drilling, could result in MAHs. A risk analysis here is based on the dimensioning loads prepared for the FDPSO. Estimation of any frequencies of such events is not possible to any proper degree of certainty, so a discussion of the consequences will be covered in an eventual risk assessment. Input is taken from the HAZID.

3.1.8.5 Other Events

Other events that might have a risk contribution do not fall under the above-mentioned categories. Examples are:

- Work accidents (personal injury),
- Helicopter accidents.

These studies will generally not have potential of MAHs, and will therefore not be necessary for the current application. However, this general risk contribution should not be ignored when assessing the total risk contribution to personnel.

3.1.8.6 Consequence Analysis

The consequence analysis aims to describe the actual consequences of the different accident scenarios (fire, explosion, ship collision, etc.). Each accident scenario may result in consequences such as:

- Exposure of personnel,
- Exposure of a third party,
- Environmental exposure,
- Financial loss.

Consequences related to exposure of personnel will focus on the risk exposure to personnel working on the installation. There are a few approaches to consider here. For a quantitative study, risk metrics such as Fatal Accident Rate, Individual Risk per Annum and/or Group Individual Risk will provide values for fatality for the different personnel groups present. When following a qualitative approach, a discussion will be presented covering the different accidental events and the possible exposure of personnel. Common for both approaches will be a systemization of the accidental events; common examples here are fires, explosions and ship collision. For most cases, accidental events involving loss of containment of hydrocarbons will be the most severe accident with the most serious consequence. As such, a focus on the consequences of fire will be a priority. The detail level of such a consequence analysis depends on the size of project. Simple assessments using hand calculations and engineering judgment may be used, but with the possibility of overestimating the risk to ensure conservatism. Simple computer models can be used to some extent, but the user should be aware of the limitations of such tools. If the demand is present, then a CFD approach can be taken, giving specific details on the spread of fires and/or explosions. This is very time-consuming and somewhat costly, and the use will have to be justified within the limitations of the study.

Exposure of a third party can be relevant in some cases. Operations close to residential areas or other places where people are routinely present may be of concern. For most offshore applications, however, this is not relevant; which is true in the current application for an FDPSO.

Exposure of the environment will always be an important concern when analyzing operations in the oil and gas industry. Historically we have seen releases of hydrocarbons in the environment having extensive effects. The area of the operation is important to consider when doing this type of analysis. Some geographical areas are more sensitive than others are. That is, while HC releases to the environment are not acceptable, some areas might be more sensitive than others might and, as such, the consequences should be studied in detail.

With regard to financial loss, this will largely, be a function of the other consequences. Accidents resulting in personnel injuries will result in loss of time, which in turn is a financial loss. The same might be said for exposure of third party. A release to the environment will require clean up to some degree, which will most likely be costly. In addition, smaller incidents that might not have very severe consequences, may lead to loss of production time and in turn a loss of revenue. Based on this, it can be said that all accidents leading to loss of containment or significant structural damage will have a financial loss of some magnitude.

An escape and evacuation risk analysis (EERA) will provide information on the exposure and possible impairment of escape and evacuation routes on the FDPSO. This study will need input from the other analyses on the possible accidental events that should be included.

Exposure of the different barriers on the installation will be a part of the consequence analysis. Some barriers work as accident prevention while others serve to minimize consequences (e.g., firewalls). For example the failure of a separating barrier to restrict the accidental event to the initiating area could result in the event escalating to another segment containing hydrocarbons, thus resulting in a larger fire. This is very relevant for the case at hand where an initial fire in the process area could escalate to the wellhead area exposing the SBOP to fire damage. This could mean loss of the SBOP and possibly a well event. Another example is a cargo tank or pump room explosions that could impair the SBOP functionality. Either event will result in a scenario where the functionality of the SDS is imperative to avoid a well event. Impairment of other relevant barriers will also be analyzed, based on input from the barrier analysis. Relevant barriers will be discussed within the context of the relevant analysis, e.g., blowdown and isolation in the process risk analysis. The analysis should cover failure of the barrier upon demand (e.g., failure of fire detection) and/or failure of the barrier because of accidental exposure (e.g., loss of SBOP due to dropped object). The barrier analysis will cover physical (e.g., SBOP or gas detection) as well as non-physical barriers (e.g., distance between modules).

Table 5 gives an overview of the studies presented in this chapter and the applicability to the current application.

Table 5: Suggested Studies

STUDY	Include	Comment
EERA	X	Provide information on impairment of escape routes and evacuation means. Focus on exposure of escape routes and evacuation means to fire loads with SBOP in place. This will be discussed as part of the consequence analysis, i.e., no separate study will be presented.
Dropped Objects Study	X	Assess exposure of the SBOP to dropped objects in the derrick.
Collision Risk Assessment		Will provide information on potential collision risk, but is independent of the installation of an SBOP.
Helicopter Risk Assessment	X	Will only provide information on risk contribution to personnel, not dependent on installation of SBOP. Will be briefly covered to illustrate the difference of a non-MAH scenario.
Blowout Risk Assessment	X	Very important, will provide information on risk contribution from well events – i.e., events that are related to the SBOP system.
Other Release Fire Assessment		No study required based in findings in HAZID.

STUDY	Include	Comment
Environmental Risk Analysis (ERA)	X	Important, Provides consequences of release to the environment. No separate study will be performed, but the environmental consequences will be discussed as part of the risk analysis.
Explosion Risk Assessment	X	Exposure of physical barriers to explosion loads, and subsequent exposure from fires. Explosion risk will be discussed where applicable, hence to specific study performed.
Riser Release Risk Analysis	X	Provides information on risk contribution from riser releases; should especially investigate possibility of exposure of SBOP (escalation).
Cargo Tank and Pump Room Explosions	X	Very severe consequences, should be performed to investigate possible effect on SBOP efficacy.
Process Release Risk Analysis	X	Risk contribution from process releases; should focus on possible exposure of the SBOP.
Extreme Weather Risk Analysis	X	Minor study to be performed to investigate whether loss of FDPSO due to extreme weather will lead to a well event; i.e., verify that functionality of SDS for these circumstances is sufficient.
Fatigue/Material Weakening		No specific study included based on findings in HAZID.
Occupational Accidents		Will only provide information on personnel risk, independent of installation of SBOP. Will be briefly covered to illustrate the difference of a non-MAH scenario.
Fire load Analysis	X	Exposure of critical elements to fire loads; especially potential exposure of SBOP to fires in other areas (escalation).
Marine Operations	X	Will give a brief discussion on marine events like stability or anchor faults.

This chapter has presented the risk assessment work that should be performed. Important to note from this section is the list of studies suggested in Table 5.
The following additional studies should be examined/updated/performed:

- Process release study, possibility of a fire in the process area exposing the SBOP.
- Well event release study. Will investigate effects of SBOP on well events.
- Accidental events not likely to lead to MAH will only be briefly treated further on.
- Note any significant differences in consequences of accidental events, personnel/third party/environmental/financial.

3.2 Surface BOP Specific Additional Risk Assessment

3.2.1 Purpose

This chapter presents the study basis and the results of the risk assessment performed for the qualification of emergent technology. The choice of studies performed is based on results from the HAZID and the relevant technology studied (the SBOP system in this case). The risk assessment is performed to aid in the decision process for verification permitting of the emergent technology. If the risk assessment shows an unacceptable increase in risk due to the new technology, then additional safety measures may be required that the new technology may not receive approval. Conversely, if the risk is shown to decrease and the barriers analysis results accepted, then a good basis exists for the regulator to determine if permitting is appropriate.

3.2.2 Background

After performing the HAZID study, the next step in the methodology for verifying emergent technology is a risk assessment follows a barrier analysis.

The considered scenario for this risk analysis is "Surface BOP on FDPSO with drilling and production". The main focus of this study will be on identifying risk chances associated with switching ng from a subsea BOP system to a surface BOP system (w/ subsea SDS)

3.2.3 Study Basis

3.2.3.1 FDPSO Layout

The FDPSO is divided into the following main areas as shown in the Figure 3:

- A1 – Living Quarter
- A2 – Drilling Derrick
- A3 – Main Deck Area
- A4 – Process Area
- A5 – Utility Area
- A6 – Storage Tanks/Hull

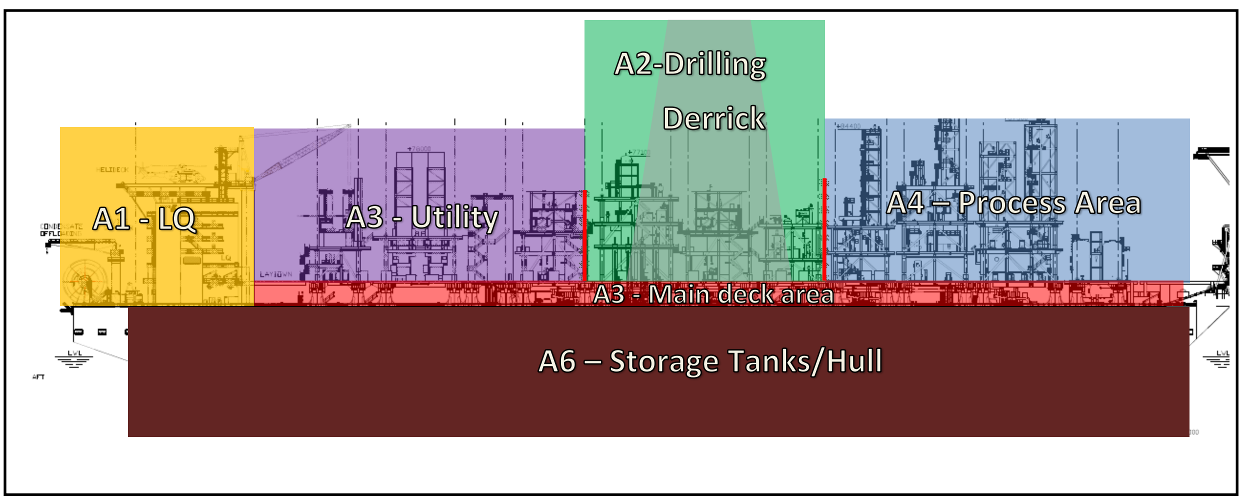

Figure 3: Main Areas of the FDPSO, Seen from the Side.

3.2.3.2 Assumptions

This section will present relevant assumptions made in this study (Table 6).

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Table 6. FDPSO Risk Analysis Assumptions

Assumption No.	Description
1	SDS will automatically shear the drill pipe, sealing the well if the drill riser is disconnected from the SDS; e.g., if the drill riser drops/buckles as a result of loss of SBOP or in the case of a drift-off.
2	Control of the SBOP and the SDS can be performed from the driller's cabin in the derrick or from the control room, located close to the LQ.
3	The FDPSO is connected to import/export risers towards the stern and as such is assumed not to weathervane.
4	The SDS is unable to cut casing or riser joints.
5	For subsea release, the entire volume of released HC will reach the surface.

3.3 Major Accident Hazards Review

3.3.1 Purpose

This section will provide definitions of the MAHs identified in the HAZID. Only the defined accident scenarios with potential for MAHs have been included; further, the discussion will be directed towards changes in risk due to the application of an SBOP versus a subsea BOP.

3.3.2 General

This section will give an overview of the methodology applied for the different parts of the risk assessment, and establishes the scenarios and corresponding frequencies for hydrocarbon releases. The following hazardous events which are commonly included in standard risk analyses for offshore installations are:

- Process Events
- Well Events
- Riser and Pipeline Events
- Failure of Mooring System or Other Positioning Faults
- Dropped Objects
- Occupational Accidents
- Helicopter Accidents
- Cargo Tank Explosion and Pump Room Explosions
- Other Hazards

For the scope of work of this analysis, an in-depth study of each of these hazards is not necessary. The focus is to review each analysis for changes in risk resulting from the use of a SBOP with an SDS, versus a typical subsea BOP. Therefore, some of the above-mentioned hazardous events will not be considered at this time, some will be briefly mentioned, and hazardous events that are expected to be affected by use of an SBOP will be given particular attention.

The remainder of this section describes the methodology and data applied in the study.

3.3.3 Process Events

A process event is defined as a release from process equipment (piping, flanges, vessels, compressors, valves, etc.) involving hydrocarbons. The study usually only examines normal production operations. Special activities (e.g., modification activities) are not considered. Special activities should, however be considered as and when required on a case-by-case basis.

The main process related fire and explosion hazards caused by release of hydrocarbons on the FDPSO are related to:

- Riser ESD valves,
- Pipeline downstream of riser ESD valves,
- Hydrocarbon systems in the process area, such as a separator,
- Manifolds,
- Crude handling systems.

The process system consists of isolable segments divided, in general, by Emergency Shutdown Valves (ESD) and isolation valves (Process Shutdown Valve (PSD)) fitted with dedicated PSD solenoids. In order to get a clear picture of the risk contribution from process events, representative leak scenarios distributed across leakage medium and release size have been defined. By doing so the consequences of a specific process event can be discussed in detail; e.g., the consequences of a '*large pool fire*' (see Table 7 for leak rate categories).

3.3.3.1 Leakage Frequency

In order to analyze the risk contribution posed by each segment it is first necessary to analyze the frequency with which leakages occur from each segment. Piping and Instrumentation Diagrams are used to count the number and type of equipment items contained within each segment. The information is then combined with leakage experience data from the Hydrocarbon Release Database (HCRD) (Reference ii) defining the leakage frequency per equipment item.

The leakage frequencies calculated are defined in Table 8. For the purposes of the analysis performed herein significant leakages are those with a leakage rate exceeding 0.1 kg/s for oil and 0.1 kg/s for gas.

Table 7: Leakage Rate Categories (Typical)

Medium	Leakage Rate [KG/S]		
	Small	Medium	Large
Gas	0.1 - 1.0	1.0 - 10.0	> 10.0
Oil/condensate	0.1 - 1.0	1.0 - 20.0	> 20.0

Table 8: Hydrocarbon Leakage Frequencies per Process Segment

Segment	Leakage Frequency [per year]			
	Small	Medium	Large	Total
PS0 - Gas export riser top	2.61E-04	1.10E-04	3.99E-05	4.11E-04
PS1-L Production header	6.21E-04	1.13E-04	6.57E-05	8.00E-04
PS2-G 1st stage separator gas	6.60E-03	6.64E-03	8.54E-04	1.41E-02
PS2-L 1st stage separator oil outlet	3.48E-03	4.97E-04	3.35E-04	4.31E-03
PS3-G LP suction scrubber – Gas	3.39E-03	3.23E-04	1.90E-04	3.90E-03
PS4-G 1st stage HP suction cooler, scrubber, compressor + 2nd stage HP cooler	9.99E-03	2.11E-03	4.33E-04	1.25E-02
PS4-G inlet 1st stage HP suction cooler and scrubber	1.09E-02	9.16E-03	6.09E-04	2.07E-02
PS4-L 1st stage HP - oil outlet	1.22E-02	1.02E-02	8.93E-04	2.33E-02
PS5-G Glycol contactor inlet scrubber and glycol contactor - Gas	9.23E-03	6.96E-04	1.03E-04	1.00E-02
PS0 -L Production riser top	2.13E-02	1.55E-03	1.09E-03	2.39E-02
PS6-G Fuel gas system – Gas	2.93E-02	3.04E-03	1.57E-03	3.39E-02
PS7-G Gas metering header	8.06E-03	4.04E-03	7.91E-04	1.29E-02
PS8-G Gas export header	7.84E-03	3.78E-03	7.06E-04	1.23E-02
PS9-L Offloading	3.20E-03	3.38E-03	3.06E-04	6.89E-03
PS10-L Cargo tank heaters	5.31E-03	5.43E-03	4.02E-04	1.11E-02
Total gas leakage frequency [per year]	**8.56E-02**	**2.99E-02**	**5.30E-03**	**1.21E-01**
Total oil leakage frequency [per year]	**4.61E-02**	**2.12E-02**	**3.09E-03**	**7.04E-02**
Total leakage frequency [per year]	**0.19**			

The total annual process leak frequency for the FDPSO is predicted to be 0.19 per year. This is split between 0.12 per year for gas leaks and 0.07 per year for liquid releases.

3.3.4 Well Events

This section presents an assessment of frequency associated with blowouts and well releases. This assessment is based on experience data as published by SINTEF (Reference iii) and Lloyd's Register Consulting[4] (Reference iv).

A *well event* is the common term for two types of releases, blowouts and well releases. A blowout is defined as an incident where formation fluid flows out of the well or between formation layers after all the predefined technical well barriers or the activation of the same have failed. The reported incident is classified as a well release if oil or gas flowed from the well from some point where flow was not intended and the flow was stopped by use of the barrier system that was available on the well at the time the incident started.

[4] Reference iv was previously issued by Scandpower (now acquired by Lloyd's Register).

3.3.4.1 Release Scenario

The release scenarios of a blowout or well release will depend on a number of factors, including, but not limited to:

- Release locations
- Release rates
- Durations

3.3.4.2 Release Location

Possible release locations for blowouts and well releases are generally assessed based on operation type and location of main equipment items, assisted by experience data as summarized by SINTEF (Reference iii). For this study, a simpler approach has been chosen. Blowouts and well releases subsea will result in a pool on the sea surface. If a well event were to happen topside, it is assessed that this will occur in close proximity to the SBOP, i.e., near the moonpool, derrick, drill floor etc.

3.3.4.3 Release Rates

Two release rate categories have been established for this study; *restricted flow* and *full flow*. The difference in these categories is the size of the release. This will then account for instances that lead to a restriction in the flow, e.g., annular flow. Table 9 presents the corresponding representative release rates for blowouts and well releases. It is considered that releases in the *restricted flow* category are more likely than releases in the *full flow* category. Blowout rates have been poorly documented in industry experience data and a distribution between different release rates is not available. Assumed probabilities of distribution for different release types are presented in the table; these assumed probabilities are commonly used in similar applications where representative data is not available.

Table 9: Representative Release Rates

Release Type	Restricted Flow		Full Flow	
	Flow Rate [kg/s]	Probability [%]	Flow Rate [kg/s]	Probability [%]
"Average" blowout	35	80	150	20
"Average" well release	35	80	150	20

A representative well fluid with a Gas to Oil Ratio (GOR) of 550 has been assumed. Consequently, approximately 45% of the flow rate is assumed to be gas, for deep blowouts and well releases. The GOR value will play an important part in the risk assessment. A high GOR means large amounts of gas, further resulting in a higher probability of ignition. A low GOR (more oil) release will be harder to ignite, but the environmental consequences are far more severe. In actuality, the release will be a mix of gas and oil, as indicated by the GOR value. The assessments made in this study will cover gas and oil releases to give an overview of the possible consequences.

3.3.4.4 Durations

A distribution of durations from blowouts and well releases is calculated based on Lloyd's Register Consulting's report "Blowout and well release frequencies based on SINTEF offshore blowout database 2013" (Reference iv). The duration distributions for blowouts and well releases are presented in Figure 4 and Figure 5, respectively.

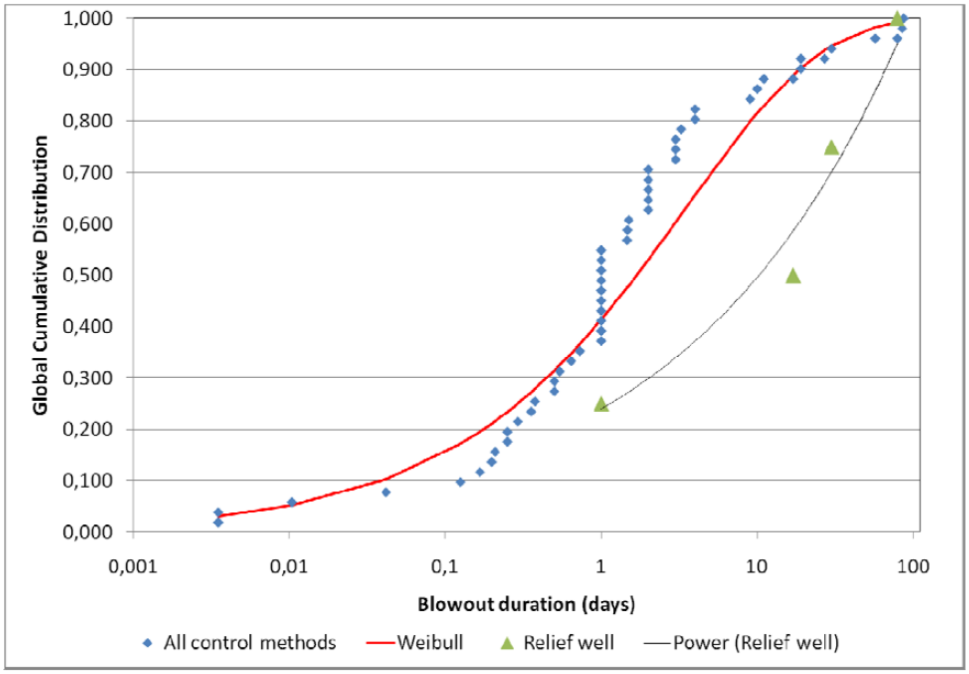

Figure 4: Cumulative Probability of Release Duration for Blowouts (Reference iv)

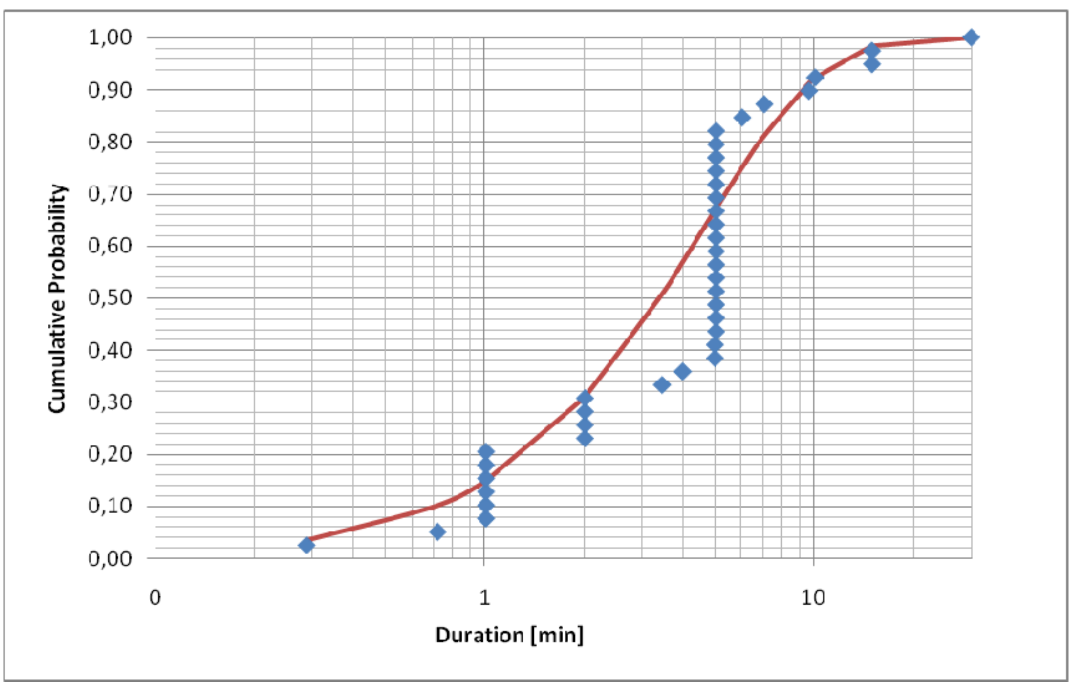

Figure 5: Cumulative Probability of Release Duration for Well Releases (Reference iv)

Well releases are generally of a much shorter duration than blowouts. Well releases are brought under control by the barrier system available at the time of the incidents, whereas blowouts are not. Thus, blowouts can last for days and months, while most well releases are brought under control within minutes. For manned installations in the North Sea and the Gulf of Mexico, approximately 70% of experienced well releases have been controlled within 5 minutes after the initial release and all have been controlled within 15 minutes (Reference iv).

3.3.4.5 Leakage Frequency

The Lloyd's Register Consulting report (Reference iv) presents base event frequencies for blowouts and well releases from different well operations based on experience data. Combined with the assumed number of different operations, annual release frequencies have been estimated and are presented per mode of operation in Table 10. Shallow gas blowouts are not considered since the FDPSO is on a developed production field.

Table 10: Annual Estimated Frequencies of Well Releases and Blowouts

Operation	Number of Wells per Year	Type	Annual Frequency, Average Well
Development Drilling, Deep (Normal Wells)	4	Blowout	1.52E-04
		Well Release	1.54E-03

3.3.5 Riser and Pipeline Events

Riser and pipeline events are hydrocarbon leaks, which can ignite and lead to a fire and/or explosion. The non-ignited oil-leaks can additionally lead to pollution, while a non-ignited gas-leakage can lead to hydrocarbon gas exposure of personnel.

A 10" flexible riser and steel pipeline containing oil and a 12" flexible gas export riser is included in this study; detailed information per riser given in table below.

Riser	Dimension [IN]	Length to SSIV [M]	Total Length Incl. Pipeline [KM]	Temperature [°C]	Pressure [BARG]
Oil Riser	10	-	2.8	60	10
Gas Export	12	871	7	55	172.5

The boundary between process and riser systems in the analysis is the riser Emergency Shutdown (ESD) valve on the riser balcony. If a leakage occurs the whole volume of the riser and pipeline may leak.

There are several possible causes of incidents to risers and pipelines, which may result in leakages. The most important causes are listed below:

- External forces such as anchoring, trawling, dropped objects, ship collisions, etc.
- Corrosion, erosion (internal or external corrosion).
- Structural failures, such as expansion, clamp failures or buckling.
- Material failures such as weld failure, steel failure or flexible-line defect.
- Natural hazards such as vibration, storm, scour or subsidence.

Representative release scenarios have to be defined in order to calculate the risk. Criteria for scenario selection are a combination of physical parameters, such as volume, location of possible leaks (above/below splash zone and leaks on the seabed) and leakage rate. A representative release scenario involves a combination of these parameters. The representative scenario will not be worst case, but instead be viewed as 'the average' or 'most likely' release. The representative scenario must be chosen to give a reasonable, but conservative, representation of the risk.

Figure 6 demonstrates the release scenarios for risers and pipelines included in this study. For the riser the two release scenarios considered are:

- Zone A: releases above the sea surface;
- Zone B: release from the hull down to seabed.

For the pipeline, the defined release scenario considered is:

- Zone C: from the riser base to the safety zone limit of 500m[5]. Figure 6 shows the risers tied back to the well of the FDPSO. Note that this is only an example and not relevant for this study as the pipelines also stretch away from the FDPSO.

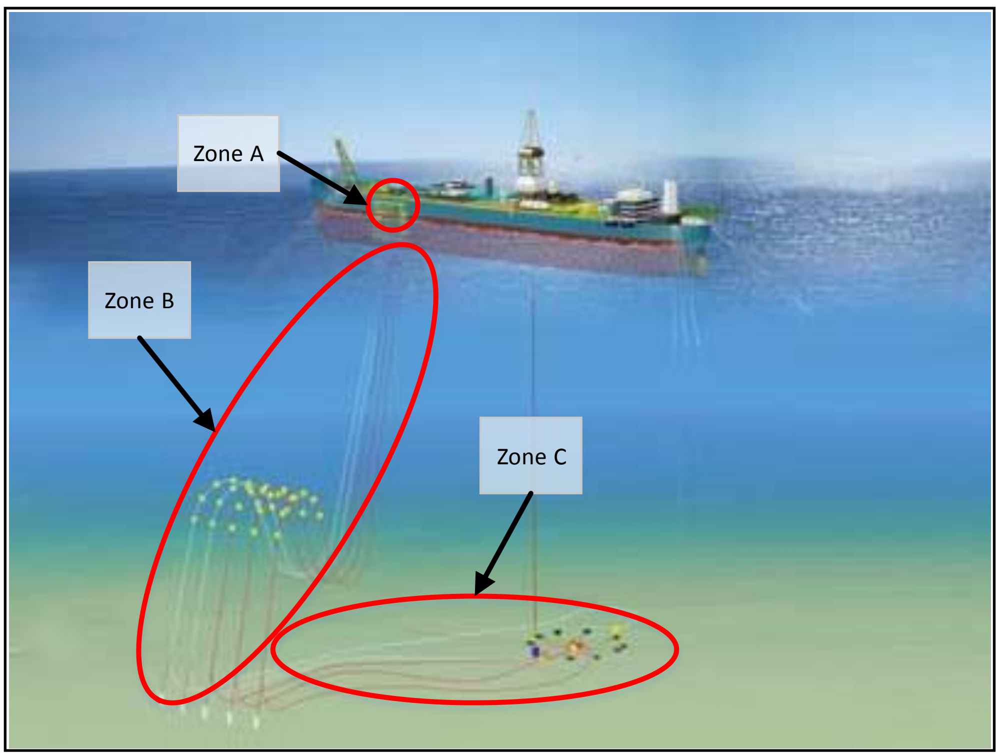

Figure 6: Definition of Zones for Leakage Scenarios

On this basis, six leak scenarios are defined, as in Table 11.

[5] The Safety Zone is 500m away from the FDPSO. However, it is assumed that only leaks occurring within a distance of 100m from the FDPSO will pose any risk.

Table 11: Leak Scenarios for Riser and Pipeline

Scenario	Medium	Riser/Pipeline	Zone/Area
R1A-oil	Oil	Oil import	Zone A
R1B-oil			Zone B
R1C-oil			Zone C
R2A-gas	Gas	Gas export	Zone A
R2B-gas			Zone B
R2C-gas			Zone C

The initial leak rates and durations are summarized in Table 13. The duration is estimated by looking at the time required for the release rate to drop below the applied cut-off rates of 0.1 kg/s or 5 kg/s. It is not significant for this analysis whether the leak lasts 120 minutes or longer. The term “>120’’ is therefore used whenever the duration exceeds 120 minutes. Durations are given for two different cut-off rates. The applied hole sizes are translated to leak rate categories using the data in Table 12.

Table 12 Hole Sizes Applied In This Study

Size Category	Hole Size (mm)	Representative Hole Size (mm)
Small	0 – 20	10
Medium	20 – 80	50
Large	> 80	*Full Rupture*

Table 13: Initial Leak Rates and Durations

Riser	Equivalent Hole Diameter (MM)	Initial Leak Rate [KG/S]	Duration [MIN]	
			Cut-Off Rate 0.1 KG/S	Cut-Off Rate 5 KG/S
Oil Import	10	0.7	> 120	-[6]
	50	16.5	21.00	5.13
	355.6	834.1	0.18	0.18
Gas Export	10	1.5	> 120	-[6]
	50	36.6	20.77	7.33
	304.8	1360.1	0.33	0.33

3.3.5.1 Leakage Frequency

The leakage frequencies used for risers are based on historical experience data summarized within the PARLOC report (Reference v). This report includes a detailed incident database, containing details of a total of 542 incidents associated with operations of North Sea pipelines until the end of year 2000.

[6] The initial rate is less than the cut-off rate.

The model used to calculate the leak frequency due to risers and fittings takes into consideration the following parameters:

- Number of Risers and Pipelines
- Length of Riser/Pipeline
- Dimension
- Riser Material
- Localization (Above/Below Sea Surface, Protected/Unprotected Riser/Pipeline)
- Hole Size
- Number of Fittings
- Ship Collision
- Dropped Objects

The base frequencies are based on Det Norske Veritas (DNV's) *Energy Report - Recommended Failure Rates for Pipelines* (Reference vi). It is distinguished between internal events, external events and equipment events. Internal events include all events that happen directly to the riser/pipe, like corrosion and fatigue. While anchoring, dropped objects and ship collisions are considered as external events. Equipment events are events that are caused by equipment on the riser/pipeline.

The distribution between riser leaks above splash zone (Zone A) and below splash zone (Zone B) is based on the DNV Report (Reference vi). Given that a leak occurs on a flexible riser (Zone A and B) or a pipeline (Zone C), the hole size distribution is calculated based on the DNV Report (Reference vi).

An additional contribution is added to the leak frequencies for the riser and pipeline if equipment/fittings such as flanges, valves and/or instrument connections are present. The additional contribution to leak frequencies from equipment is found from the HSE UK leakage database (Reference ii).

Leak frequencies for the riser and pipeline on the FDPSO are summarized in Table 14.

Table 14: Total Leakage Frequencies for the Risers and Pipelines

Scenario	Annual Frequency per Hole Size (1/yr.)			Total
	Small	Medium	Large	
R1A-oil	2.25E-03	1.12E-03	1.04E-03	**4.41E-03**
R1B-oil	5.19E-04	6.65E-04	6.65E-04	**1.85E-03**
R1C-oil	5.54E-05	4.69E-06	3.65E-06	**6.37E-05**
R2A-gas	7.24E-04	9.95E-04	1.00E-03	**2.72E-03**
R2B-gas	4.73E-04	6.63E-04	6.63E-04	**1.80E-03**
R2C-gas	3.76E-06	5.44E-06	1.67E-05	**2.59E-05**

3.3.6 Explosion in Cargo Tanks

An explosion in a cargo oil tank is a potentially very severe accident. The explosion can cause critical structural damage to the main deck and bulkheads. If the explosion occurs in a cargo tank with some amount of crude oil present, the explosion is likely to lead to a subsequent fire. If the integrity of the main deck is breached, damage to topside equipment could cause additional release of hydrocarbons and an escalated scenario. An explosion in the cargo tanks or pump room of the FDPSO is expected to have very serious consequences leading to massive damage. This could mean loss of the SBOP and further loss of containment in the well. In the worst case, a cargo tank or pump room explosion could result in immediate loss of the FDPSO.

3.3.7 Failure of Mooring System or Other Positioning Faults

The FDPSO is moored in place with long anchor chains. If the anchor chains were to break, this could lead to the FDPSO drifting off its location. This type of breakage could result from for example impact from passing vessel anchor; fatigue of the chain or failure of the anchor itself to remain fastened to the seabed. Examples of historical incidents are given in Table 15. Three of the four events mentioned here are due to extreme weather; i.e., there is a strong correlation between this scenario and extreme environmental loads (Section 3.3.10).

Table 15: Examples of incidents resulting in anchor breakage (Reference vii)

Year	Vessel	Damaged Component	Age of Component	Incident	Likely Causes
2011	Banff	5 Chains	12 years	**5 of 10** lines of the turret mooring separated. Vessel drifted 250 meters off location during severe weather.	
2011	Gryphon Alpha	4 Chains	19 years	**4 of 8** lines separated in chains in heavy storms. Vessel drifted a distance causing riser to break.	100-mph wind gusts; Possible flaw in flash weld of chain link
2009	Nan Hai Fa Xian	4 Wire ropes	19 years	**4 of 8** lines separated in bottom end of upper wire segments in a sudden typhoon. Vessel had no time to disconnect from its BTM buoy. Vessel drifted a distance causing risers to break.	Typhoon; Disconnectable FPSO could not disconnect in time, overloading mooring lines; Degradation of wire ropes.
2006	Liuhua (Nan-Hai Sheng Li)	7 Wire ropes	10 years	**7 of 10** lines separated in a typhoon. Vessel drifted a distance causing risers to break.	Typhoon exceeding design limit; Degradation of wire ropes.

3.3.8 Dropped Objects

Lifting will be performed in the derrick above the SBOP, a drop could result in critical damage. Frequency estimates are not available for this study, so a discussion on the possible consequences will be presented.

3.3.9 Helicopter and Occupational Accidents

Helicopter and occupational accidents will directly affect the risk that personnel working on the FDPSO are exposed. Helicopter accidents can happen during take-off/landing or in transit. The consequences will generally be severe, possibly resulting in fatality of all crew and passengers.

Occupational accidents are other types of accidents that may happen when working offshore; e.g., man over board or falling while working at heights. The consequences may vary from minor injuries to fatalities.

These types of accidents are not referred to as MAHs; in addition, they will not be affected in any way by the choice of BOP solution. It is therefore chosen not to further assess these types of accidents in this risk assessment. However, this is not say that they do not pose a significant contribution to the general risk level, but rather that they do not create significant additional risk due to the use of an SBOP.

3.3.10 Other Hazards

Other hazards are generally low frequency events not covered by the other categories presented in this section. For this study, the most prevalent example is extreme environmental loads. Extreme environmental loads are loads caused by extreme weather or other natural phenomena like earthquakes.

Extreme environmental loads could have an adverse effect on the stability of the FDPSO and its ability to remain in position. If an extreme event results in total loss of the FDPSO, the SDS will lose its connection with the FDPSO and automatically try to seal the well. A similar event could also result in the anchor chains breaking and the FDPSO drifting off location; this is discussed in Section 3.3.7. The effect of using an SBOP versus a subsea BOP will be the same for this scenario as discussed in Section 3.3.7.

An earthquake will not directly affect the FDPSO since it is floating. However, this could result in one or more of the anchors coming loose. This may result in the FDPSO losing position as discussed in Section 3.3.7.

There are no other hazards relevant for this study. Therefore, based on the above discussion, the consequences of other hazards and the effects of using an SBOP are similar to those found when discussing loss of position scenarios (Section 3.5.7).

This section has presented the MAHs identified in the HAZID. This section is based on the studies listed in Table 5 Important notes from the past section:

- Only the accidental events with potential for MAHs are taken further; e.g., helicopter accidents, even though viewed as a serious accident, are not taken further as they don't have MAH potential and thus the choice of using an SBOP will not be affected by or affect this type of accident.
- Extreme events, resulting in loss of the FDPSO, are specifically noted for several accidental events.

3.4 Consequence Analysis

3.4.1 Ignited HC Release Consequence Assessment

Ignited HC scenarios result from a number of initiating events. For such events, the consequences may be assessed in a similar manner; also in some cases, the consequences of two different initial events (e.g., process and blowout) may be the same. The current study will assess the following initiating events for ignited HC events:

- Process Events
- Well Events
- Riser Releases

The major difference between these events is the release location and the magnitude of the release (i.e., release size and duration). This has previously been presented in this chapter (Section 3.3.3 to 3.3.5); refer to these sections for in-depth details.

An ignited HC event will affect the risk level of the FDPSO through exposure of structures to heat loads; exposure of safety critical elements to heat loads and/or smoke loads; or direct exposure of personnel.

Exposure from heat loads will come from the actual fire. This could result in failure of a given structural element, which could in turn reduce the possibility of personnel to safely evacuate; impair safety critical elements like the control room; or result in total loss of the FDPSO. If other segments containing HC are exposed to sufficient heat loads over time, the exposed segment could burst resulting in a secondary ignited event. Such escalated events are expected to have a more significant consequence compared to the initial event.

Exposure of safety critical elements to heat and/or smoke loads could mean loss of use of evacuation means. For example, the life boat station being covered in smoke such that personnel are not able to safely board and evacuate the FDPSO.

Direct exposure of personnel will result in fatalities. This could happen in the initial fire or exposure from any subsequent fires due to escalation to other segments.

3.4.2 Unignited HC Release Consequence Assessment

In the case of a release of HC that does not ignite, there are possible consequences to personnel and the environment.

Exposure of personnel can be toxic, possibly resulting in fatalities. The probability of fatality will depend on the type of toxic exposure and the magnitude of the dose, concentration and duration of the exposure. Certain toxic gases, e.g., H_2S, are lethal at low doses while other toxic materials will require more significant doses.

An unignited release of HC will also have consequences on the environment. The severity will depend on the type of release. A blowout will have a significant duration resulting in possible catastrophic consequences. A riser release can also potentially have long durations, limited by the size of the riser. A process release is expected to have limited effects on the environment, but the potential for escalation could eventually lead to significant environmental exposure. Additionally, a release of gas is viewed as having a lower effect on the environment compared to a release of oil that may require significant clean-up.

Import notes from the past section:

- Unignited and ignited events will, naturally, have very different consequences.
- Difference in exposure of personnel leading to fatality and the critical exposure and damage to the FDPSO, possibly resulting in severe environmental and financial consequences as well as possible fatalities.

3.5 MAH Risk Results

3.5.1 Purpose

This section will present the risk results for the identified MAHs. The discussion presented here aims to illustrate the 'most likely' consequence for each accidental event, as well as the worst case. The discussion will be based around the effects of the application of an SBOP. Each accidental event is discussed initially on its' own, but the possibility of escalation from one accident type to another is discussed wherever applicable. A summary is included at the end to provide the reader with an overview.

3.5.2 General

This section will give an overview of the risk contribution from the major accidental hazards assessed.

3.5.3 Process Events

Process events occur in the process area, location seen in Figure 3. Generally, the duration of process releases will be of the order 25, 10, and 5 minutes for small, medium, and large releases. Compared to release rates of riser/pipeline and well event scenarios, the release rates of process events are viewed as limited. Therefore, the possible potential exposure resulting from an initial process event is expected to be less severe, compared to a well event or a riser scenario. However, a release in the process area does have the potential of exposing other segments resulting in a larger escalated scenario. An initially small scenario will have a longer duration compared to a large scenario; it is possible that such a scenario could expose other segments to high heat loads leading to a significantly more severe escalated event.

One very critical scenario from an initial process event will be exposure of the drilling derrick and the SBOP. An example is shown in Figure 7. The SBOP is suspended from the riser tensioning system. Exposure of the suspension wires could result in the SBOP dropping which in turn could result in a more serious well event scenario (see buckling of riser, Section 3.5.4.1). Shut-in of the well will then have to be performed with the SDS, which may be controlled from the control room. This will require the SDS to function properly in order to prevent a loss of well containment scenario. Such a scenario is expected to have serious environmental consequences, in addition to the consequences of an ignited well event (ignition assumed very likely due to already ignited process scenario).

Process events will generally impair the possibility of safe escape through the process area due to exposure of escape routes to smoke and heat. Except for the scenario where escalation of the fire involves the drilling derrick and the SBOP, the FDPSO risk is not expected to change because of employing a surface BOP.

The environmental consequences of a process leakage will generally not be adversely affected by using an SBOP, except for the case where escalation involves the drilling derrick, as discussed above.

Figure 7: Radiation Level at Weather Deck Elevation

3.5.4 Well Events

An ignited well event may appear in the drilling derrick if the release happens in/around the SBOP, in the riser above the sea surface, or on the sea surface as a pool fire. The pool fire can result from either a rising gas plume or a release of oil. The pool on the sea surface may appear at one of many locations depending on current/wind.

The closer the pool appears to the FDPSO, the more severe the potential consequence for the FDPSO. Figure 8 shows the resulting radiation exposure from a pool appearing just of the side of the FDPSO. This result is based on the wind blowing the fire away from the FDPSO, at a 15° angle of the bow. If the wind had been blowing the fire onto the FDPSO, it is expected that the exposure would be more severe, possibly resulting in exposure of process segments and further fire escalation. A pool fire on the sea surface will result in exposure of the hull to high radiation loads. If the release is not stopped, this might result in the hull cracking and the possible loss of the FDPSO. Safe escape and evacuation may also be affected depending on the location of the pool. If the pool appears off the bow, close to the lifeboats, then evacuation will be impaired. If the pool appears on both sides of the FDPSO, safe escape along the sides will be impaired such as escape from process area to Living Quarter (LQ).

An ignited well release or blowout topside will initially expose the drilling area. This will result in high heat loads exposing the SBOP, most likely resulting in structural impairment of the SBOP and loss of functionality. This could lead to the riser buckling, which is discussed in Section 3.5.4.1. Depending on the exposure of the hull, an uncontained release is likely to lead to loss of the FDPSO. As seen in Figure 4, the duration of most blowouts is on the order days, which is sufficient duration to lead to loss of the FDPSO. In this scenario, escape through the drilling derrick area will be impaired (e.g., from the process area to Living Quarters).

A jet fire in the drilling derrick directed towards the process area, as seen in Figure 9 and Figure 10, could result in process area releases, resulting in increased fire exposure. This scenario will have increased likelihood of restricted escape ways through the process area (e.g., from the process area to Living Quarters) due to the expanded fire.

The environmental consequences due to a gas pool on the sea surface (unignited) are limited since the gas will disperse into the atmosphere. A similar release of oil could have significant environmental consequences, only limited by successful shut-in of the well. Assuming a GOR of 45%, it is expected significant environmental consequences for loss of well containment scenarios are likely.

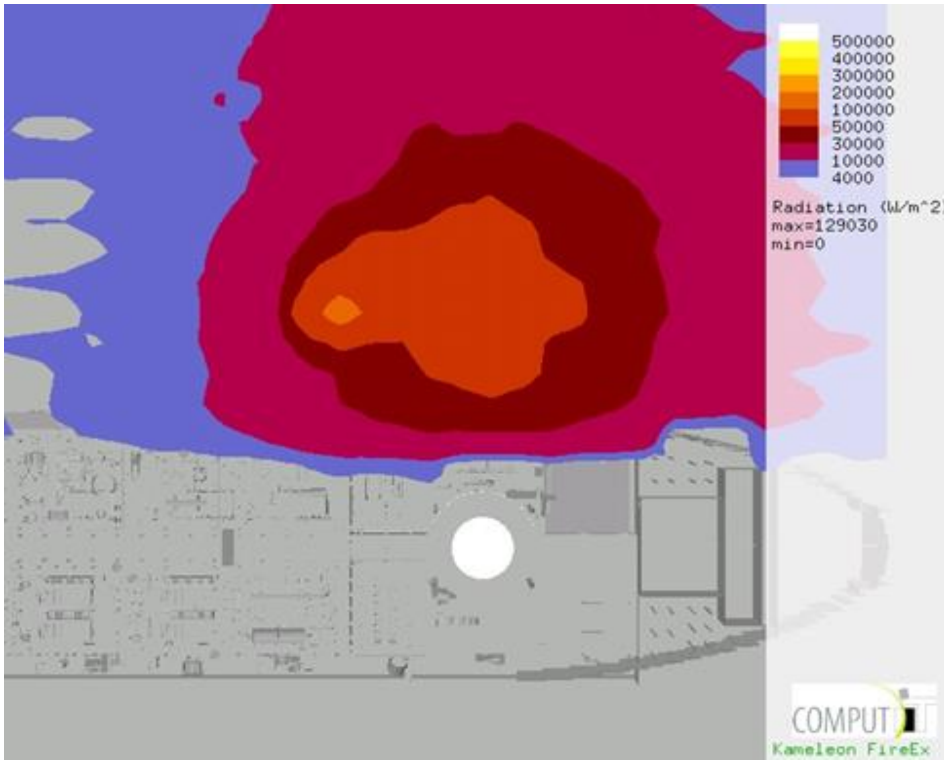

Figure 8: Ignited Gas Plume on the Sea Surface, Radiation Contour on Weather Deck Level

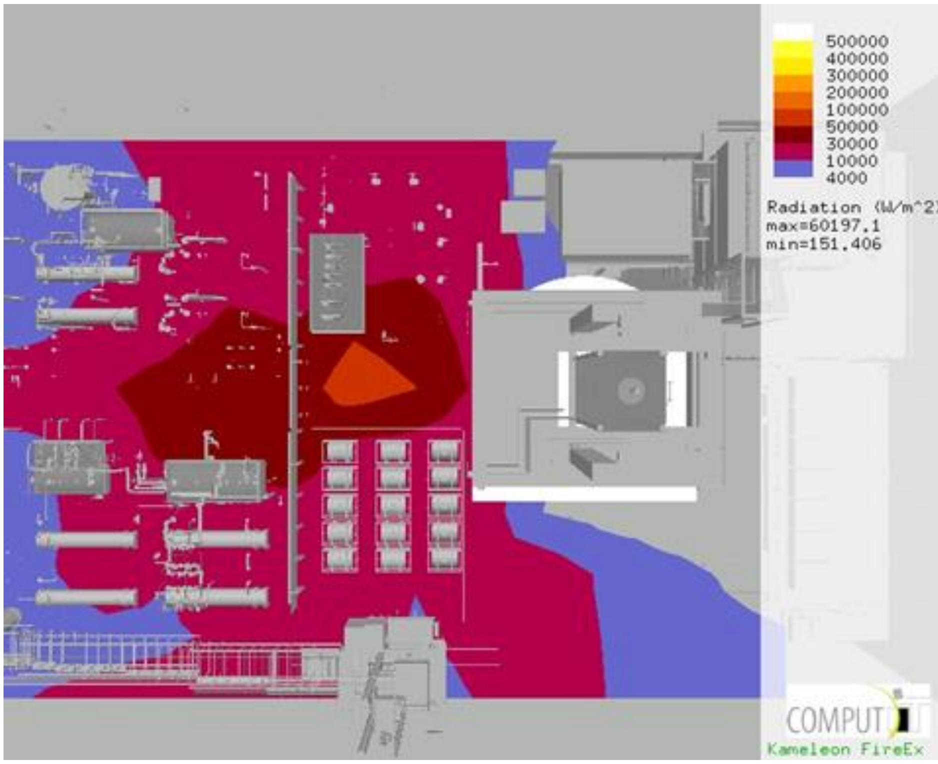

Figure 9: Gas Jet (20 kg/s) in Drilling Derrick towards Process Area, Radiation Contours on Weather Deck

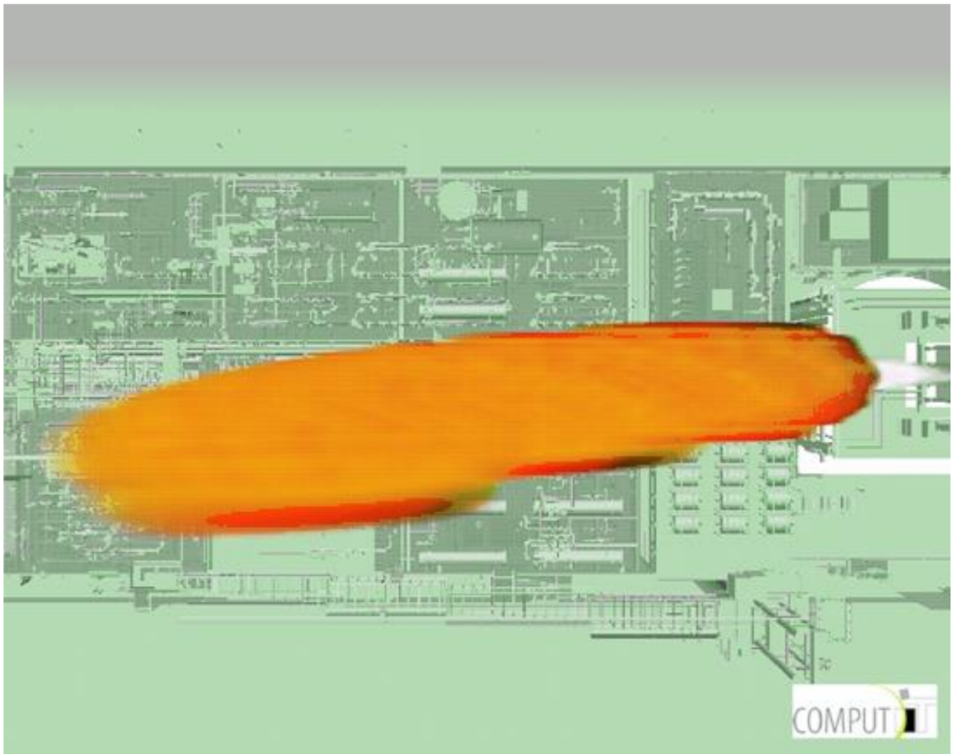

Figure 10: Iso-surface of Large Fire (50 kg/s) in Drilling Derrick, towards the Process Area.

3.5.4.1 Loss of SBOP – Buckling of Riser

There are scenarios that might lead to the SBOP being dropped from the riser tensioning system. These scenarios are unique to the SBOP, as they may not occur with a subsea BOP. If the SBOP is dropped, the drill riser will lose its tension. Thus, the weight of it could rest on the SDS. The riser is assessed to then topple over and begin to buckle. The SBOP will then rest on the riser adding to the weight and increasing the buckling. The riser will tear and spill its contents to the sea, possibly followed by the volume below the SDS. This scenario could lead to loss of well containment if the SDS is not able to properly shut in the well.

There are several events that may lead to this type of scenario, like dropped objects or exposure from fire loads. This is covered in the respective sections throughout this section.

Note that this scenario will leave only the SDS to potentially contain the release. Compared to the use of a subsea BOP, this scenario will be more severe as the SDS – as an isolated system - will have less redundancy compared to a surface BOP (fewer rams).

3.5.5 Riser Events

The risers are located towards the aft of the FDPSO as seen in Figure 3. Riser events are generally split into three types of release, depending on the location; see Figure 6.

An ignited release from the gas riser in Zone A, will expose a significant portion of the FDPSO to fire loads. Due to the high pressure of the riser, the flame is expected to be large. If the jet is directed along the FDPSO (towards the bow), large parts of the process area will likely be exposed. Figure 10 shows a very large fire (rate 50 kg/s) in the drilling derrick directed towards the process area. This example shows that a comparatively sized riser release would have a similar footprint. Escalation to other segments in the process area may be possible. A subsequent escalation to the derrick exposing the SBOP could happen under unfavorable wind conditions. Safety critical elements such as the control room, LQ/temporary refuge and the lifeboats are not expected to be exposed in the initial parts of this scenario. This means that isolation and depressurization of the process area will be initiated and if drilling is being performed at the time, sealing of the well. It is therefore imperative for such a scenario that these barriers are intact and function properly on demand. If these barriers function, the scenario will last until the riser is emptied and the consequences on personnel will be severe. If the jet is pointed such that the hull is exposed, loss of the FDPSO is a possibility.

A gas jet pointed away from the FDPSO will most likely not ignite. The subsequent release will then last until the riser is emptied. This should not have any significant effect on personnel as the gas will disperse away from the FDPSO. The environmental consequences are viewed as limited as compared with a release of oil.

A gas release in the B or C zone of the riser will lead to a gas plume rising to the surface and a subsequent vapor cloud on the surface. The consequences of this scenario are comparable to those of a well event leading to a pool on the sea surface (see Section 3.5.4). The same is true for an oil release.

3.5.6 Explosion in Cargo Tanks

A cargo tank explosion is a very unlikely scenario with no recorded incidents for FPSOs to date. The consequences are however sufficiently severe that they are included here. This scenario may evolve in two ways, (1) an explosion followed by a fire or (2) an explosion directly resulting in critical damage or even loss of the FDPSO. In case of the initial explosion resulting in total loss of the FDPSO, the SDS will have to function to avoid any major environmental consequence (loss of well containment). If a subsea BOP had been used, this would have had better redundancy compared to a stand-alone SDS, thus reducing the likelihood of a major environmental event.

3.5.7 Failure of Mooring System or Other Positioning Faults

A failure of the mooring system may cause the FDPSO to drift off its position. To result in any significant drift-off, more than one anchor chain will have to break. The FDPSO has only limited maneuvering capabilities and will most likely not be able to keep its position if multiple anchors fail. Table 15 shows examples of incidents involving anchor failures, including severe drift-off and breaking of risers.

Initially a drift-off will have an adverse effect on the risers. As the FDPSO floats away, the risers are stretched and at some point the risers will break resulting in a hydrocarbon spill. Drift off, however, not affected by the choice of the BOP-system applied. Therefore, the effect of drift-off on the risers will not be further discussed.

If drilling is performed when a drift-off happens, the choice of BOP will affect the risk. If an SBOP is used, closing the SBOP means that there is a column of well liquids up to the FDPSO. If the FDPSO drifts such that the drill riser breaks, this column is released and the well is no longer sealed. This could have serious environmental consequences due to the release of HC. The risk to personnel and the FDPSO itself will depend on where the HC surfaces relative to the where the FDPSO has drifted.

Closing the SDS is a more viable option in the case of a drift-off. This will close in the well and is not affected by the location of the FDPSO. It is likely that the drill riser will break and fall to the seabed. The impact location on the seabed is expected to be away from the well as it is guided by the drifting FDPSO. The likelihood that the falling drilling riser will impact the SDS is negligible. It is also assumed that the SDS will automatically initiate shutting in the well if the drill riser is disconnected from the SDS. If personnel on board the FDPSO do not initiate well shut-in, then the SDS will do it. The only effective barrier against a blowout in the case of a drift-off is the SDS. If a subsea BOP had been chosen instead, it is expected to have better redundancy and reliability compared to the SDS by itself (There are more rams on the subsea BOP). Using a SBOP system will result in a higher probability of a well event given a drift-off scenario.

3.5.8 Dropped Objects

While drilling, there will be lifting performed over the SBOP in the drilling derrick. If a riser part is dropped, the impact could be sufficient to lead to the SBOP dropping from the riser tensioning system. The consequences of this event will be loss of the SBOP and subsequent buckling of the riser as described in Section 3.5.4.1. In the same manner, a riser could be dropped while drilling with a subsea BOP; however for this scenario the probability is significantly lower of impact with the BOP leading to impairment of functionality.

3.5.9 Other Hazards

The effects of extreme environmental loads are assessed similar as those of loss of positioning scenarios (see Section 3.5.7).

3.5.10 Summary

This chapter has presented a discussion on the risk contribution from the different MAHs relevant for the subject FDPSO. The following is a summary of the results presented, with focus on any adverse effects of using a SBOP instead of a subsea BOP.

Figure 11 shows a summary of the leak frequencies distributed on the applied leak rate categories for the loss of containment scenarios assessed. Generally the leak frequency for smaller releases is higher compared to larger releases; the exception is riser gas releases where the contribution is comparable for small, medium, and large releases.

Figure 12 presents an overview of the initiating scenarios involving release of HC, the expected intermediary stages of each event and the subsequent consequences. The left side of the figure presents the different initiating scenarios; the colors represent the expected frequency levels with green for low, yellow for medium, and red for high frequency. The initial arrows on the left side are black, indicating no assessment on probability. The subsequent arrows in the figure are colored based on probability in the same manner as indicated above.

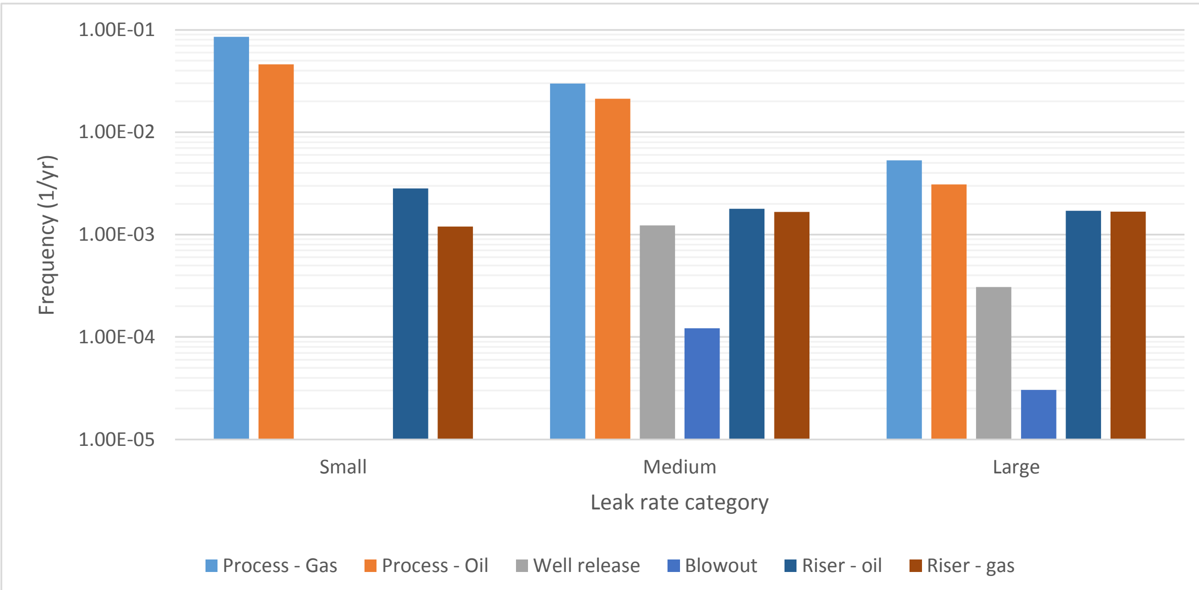

Figure 11: Summary of leakage frequencies

Process events are by far, as seen in Figure 11, the most common initial scenario. Figure 12 indicates that the possible outcomes may be release of gas or oil. A release of gas may lead to an explosion followed by a fire, or an immediate ignition without an explosion. A fire could potentially expose the SBOP, in turn leading to the unit dropping. If the well has not been shut in, an escalation to the drilling derrick result, possibly followed by loss of the FDPSO. This scenario has major environmental consequences as well as further personnel fatalities, those not exposed by the initial event. Increased fire protection of the SBOP and the riser tensioning system will reduce the potential of escalated process events.

A process release of oil is expected to have less severe consequences; also, the ignition probability of an oil release is assessed lower compared to a gas release. If the oil is not ignited, the consequences are limited to a minor environmental event as indicated by Figure 12. However if the oil is ignited there still exists the possibility of escalation to the drilling derrick and further escalation as described above.

An ignited well event on the sea surface may expose the FDPSO to high heat and smoke loads if the pool appears close to the FDPSO. The duration of such an event has the potential of lasting a long time if the well is not sealed. A long lasting pool fire close to the FDPSO may result in loss of the entire FDPSO in addition to severe environmental consequences from the release. If the leak happens in the drill riser (between SDS and SBOP), the only method for sealing the well is the SDS. If the SDS fails, the result will

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be loss of containment of the well. Note that the SDS as an isolated system and will have lower reliability compared to a subsea BOP due to fewer shear rams. In addition, the SDS is assumed not to be able to shear a tool joint, which could lead to the well not being properly shut in. A well event occurring in the drilling derrick could damage the SBOP leading to loss of its functionality and further requiring the SDS to function in order to prevent a long lasting well event.

Riser releases may come from either of the two risers (oil import or gas export). The location and medium of the release is a governing factor for the consequence. A gas release in Zone C will have minimal environmental consequences (gas will disperse into atmosphere), in addition to the financial cost of downtime and reparation of the leak. If the pool appears close to the FDPSO (Zone B), the consequences will be similar to those of a well event, for both oil and gas releases. An ignited gas release in Zone A may expose large parts of the FDPSO to high heat loads, possible escalation to the derrick, and exposure of the SBOP. Failure of the SDS in shutting in the well will then result in loss of containment of the well. A release from the oil riser in Zone B or C will result in a major environmental consequence. In addition, risk to personnel occurs if the pool appears close to the FDPSO. The use of an SBOP will have a very limited effect on the risk contribution from riser releases; the distance from the risers to the SBOP is such that the exposure is minimal. The exception is scenarios leading to escalation and critical damage to the SBOP and subsequent loss of the FDPSO.

A cargo tank explosion resulting in total loss of the FDPSO requires the SDS to function to avoid any major environmental consequence. If a subsea BOP had been used, this would have better reliability thus reducing the probability of a major environmental event. In the worst case, there is a riser joint in the shear ram at the time of accident; since the SDS is assumed not able to cut riser joints, it is necessary to move the drill riser before the well may be properly sealed. In an event such as a cargo tank explosion, this might not be possible, leading to loss of containment of the well.

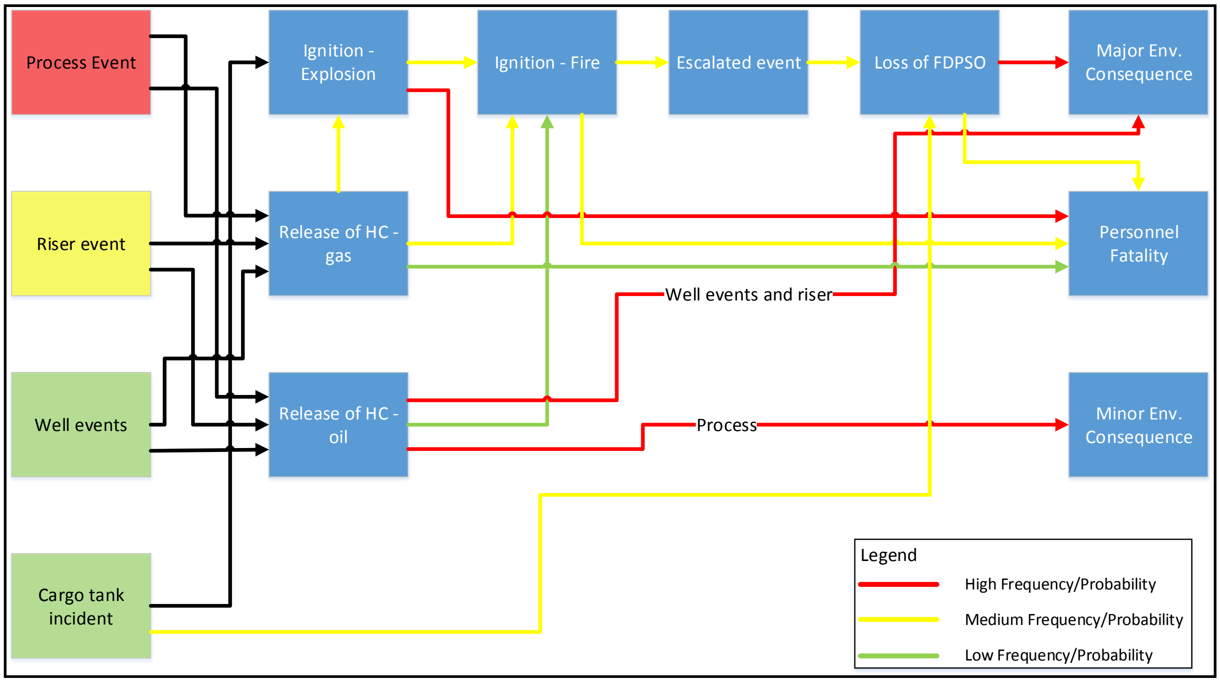

Figure 12: Overview of Risk Contribution from Release of HC

Loss of position scenarios will require that the SDS be initiated to avoid loss of well containment. Historically, extreme weather is an initiating factor for loss of position for permanently moored facilities. Such an event during drilling could in the worst-case mean loss of well containment as well as release from both risers.

This chapter has presented the risk assessment for the use of an SBOP on an FDPSO. Important points found are:

- Process releases are found to potentially expose the SBOP to heat loads leading to loss of this, leaving the SDS as final barrier against loss of well containment.
- A riser release could, in the absolute worst case, expose the SBOP to heat loads, leading to loss of this barrier and leaving the SDS as the final barrier against loss of well containment.
- Well events may occur topside or subsea, with potentially very long durations. In the worst case, a well event may lead to loss of the FDPSO.
- Failure of the mooring system was found to have similar consequences as extreme environmental loads.
- Lifting heavy objects over the SBOP (in the drilling derrick) is a critical operation with MAH potential.

Accidents leading to the SBOP dropping from the riser tensioning system found to be significant. Such accidents leave the SDS as final barrier against loss of well containment.

3.6 Conclusion

3.6.1 Purpose

This chapter presents conclusions from the risk assessment performed for the SBOP on an FDPSO. This chapter should give the reader a good understanding of the topics treated in this study, challenges to the new technology and significant contributors to risk.

3.6.2 General

This study investigated the changes to risk level on an FDPSO when using a surface BOP while drilling. The focus of this assessment has not so much been on the total risk level of the FDPSO, but rather the effects on risk from using a surface BOP versus to a standard BOP.

3.6.3 Conclusion

Table 16 presents the identified scenarios with adverse changes to risk because of using an SBOP versus a subsea BOP. The frequency and consequence columns are colored based on severity: green for less severe, yellow for slightly more severe, and red for the most severe impact on risk. For all the identified scenarios the consequence impact is of the highest category. This assessment is based on all the identified events leading to loss of well containment with severe environmental consequences in addition to risk to human life and costly financial consequences. All the identified scenarios are assessed to be low-frequency scenarios with the exception of the process event scenario. Process events generally have a greater frequency of occurrence compared to other loss of containment scenarios. However, this scenario does require an escalation to the drilling derrick and a subsequent failure of the SDS in order to possibly lead to a loss of well containment scenario.

Two categories of extreme initial events that may result in loss of containment of the well are extreme environmental loads and cargo tank explosions. These are rare, but included here due to the severe consequences of such events. Extreme weather is however not uncommon in the GoM and as such it is important to ensure that the anchoring system is designed according to the conditions it is to operate under.

Table 16: Scenarios with Adverse Changes Due to Choice of SBOP over Subsea BOP.

Scenario	Description	Frequency	Consequence
Process event escalating to SBOP	A process event could potentially escalate to the SBOP leading to it dropping and the riser buckling. The SDS must function to avoid loss of containment of well. The SDS should automatically initiate on buckling scenario (autoshear initiated if drill riser is disconnected from SDS).		
Gas release from riser	Ignited gas release resulting in exposure of SBOP and subsequent failure. Failure of the SDS to shut in the well will lead to loss of containment of the well. Similar to scenario above with exposure from process scenario.		
Topside blowout	Topside BO/WL leading to loss of SBOP. SDS must function to ensure shutting in of well. Possibility of buckling of riser. Similar to scenario above with exposure from process scenario		
Cargo tank explosion	Loss of FDPSO through cargo tank explosion will require functionality of SDS, since SBOP is most likely lost, to avoid a well event.		
Loss of position	Similar consequence with regard to environment as cargo tank explosion.		

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Scenario	Description	Frequency	Consequence
	Limited consequences to personnel or the FDPSO.		
Extreme environmental event	Same as for cargo tank explosion, but an extreme environmental event resulting in loss of FDPSO.		
Dropped object	Dropped object in the derrick impacting the SBOP leading to its failure. The SDS is the final barrier against loss of well containment.		

It is worthwhile to note that all the scenarios identified in Table 16 are scenarios where the SDS remains as the final barrier to shut in the well. This is a recurring story, due to the potential for ignited events escalating into the drilling derrick and damaging the SBOP. Increased fire protection on the SBOP to reduce exposure from such scenarios could reduce the risk. Proper separation between the main areas will also serve to reduce the risk, especially between the process area and the drilling derrick. If an ignited process event is contained within the process area, the exposure of the SBOP is minimized along with the potential for escalation to a loss of well containment scenario. The use of CFD to evaluate ignited HC events may provide further information on the possible resulting consequences. This could in turn serve as a decision basis when evaluating proper barriers to reduce potential for escalation (i.e., use of separation or a firewall).

If an SBOP is to be applied along with an SDS, it is important to ensure that the reliability of the SDS is sufficient. This study has identified some scenarios where the SDS is the final barrier against a loss of well control scenario. Failure of the SDS to properly shear the drill pipe and seal the well will result in a loss of containment scenario. Process scenarios with a non-negligible annual frequency have been shown to have an adverse effect on the FDPSO risk when using a SBOP instead of a subsea BOP.

A barrier analysis will have to be carried out to ensure that SBOP with SDS can perform it intended barrier function of **"Shut in Well and Control Wellbore"** to prevent major accident hazards. Section 4 provides the details of the barrier analysis

4. Barrier Function and Barrier Critical Systems

4.1 Barrier Function Description

The barrier function selected based on relevance for this scenario and input from the risk assessment is **"Shut in Well and Control Wellbore"**. This is the main function of the SBOP when a well kick develops. Well kicks are typically a result of loss of primary well control when drilling into formations with hydrocarbons under higher pressure than the hydrostatic pressure of the mud column acting on the borehole, or rock face. When this occurs, the greater formation pressure has a tendency to force formation fluids into the wellbore. The SBOP system is vital for the described function in these situations.

In addition to well kicks, this barrier function is also relevant for other situations like a drift-off or losing the connection between the well and the riser.

For the barrier function, "Shut in Well and Control Wellbore", the following barrier critical systems have been identified:

1. Casing and Cementing – The integrity of the casing and cementing is crucial to zonal isolation so that no other flow paths are created other than the existing one. It allows for deeper drilling when the wellbore pressure can no longer be kept within the drilling window. It provides stability and structural support for the well to avoid cratering which would make the containment of the well flow harder.
2. Wellhead – The wellhead needs to be intact, to allow an attachment point to connect the SDS to the well. Any cracks or other leak points on the wellhead could lead to spills of well flow to sea, which would not be controlled by the SBOP system.
3. Surface BOP (SBOP) – Activating the SBOP prevents the hydrocarbons from blowing out on the FDPSO vessel. Failure to activate the SBOP valves when needed can therefore be catastrophic. The SBOP also has stack-mounted valves which connect to the choke and kill lines as part of the circulation system needed to regain well control.
4. Subsea Disconnect System (SDS) – This provides the possibility for shearing the drill pipe at the seabed rather than on top of the riser. This may be necessary in drift-off situations or when the riser has lost its connection to the well. To some degree, it can also function as a redundant unit to the SBOP.
5. Tie-Back Drilling Riser – It connects the SDS to the SBOP and floater and is a continuation of the wellbore from the seabed to the surface. Like the casing, the riser integrity is crucial to ensure no other flow paths are created.
6. Drill Pipe/Drill String – During drilling operations, the drill string contains the heavy density mud, which is pumped down through it for maintaining the required bottom-hole pressure. It is considered to be part of the mud/circulation system, but the drill string also contains check valves or drill string floats which prevent wellbore fluids from entering the drill pipe and reaching the surface thereby preventing a blowout through this piping. In addition, the SBOP/SDS design should also take into consideration the dimensions and strength of the different drill strings to be used in the drilling program.

7. Mud Circulation System – As mentioned, the mud is considered the primary well barrier by providing hydrostatic pressure to prevent formation fluids from entering into the well bore. But in this scenario where a well kick has already occurred, the purpose of the circulation system is also to transport hydrocarbons out of the well and riser to depressurize the well and then pump heavy mud back in to kill the well.

5. Selected Barrier Critical Systems – SBOP and SDS

5.1 System Description and Basis of Design

In this example, focus is on the SBOP system which includes the two barrier critical systems, surface BOP and Subsea Disconnect System. The SDS, also known as the Subsea Isolation Device, is included as an integrated part of the BOP system when it comes to risk and barrier assessment.

For the development of the model, the surface BOP system was divided into six sub-systems:

- SBOP Stack
- SDS
- SBOP Control System (Hydraulic)
- SDS Main Control System (Multiplex)
- SDS Secondary Control System (ROV operated)
- Deadman/Autoshear (DMAS) Control System

A description of each of the sub-systems and their relevant barrier elements are presented below.

Figure 13 below is an illustration of a SBOP with SDS setup. Note that the control system setup for this illustration differs from the control system assumed in this report (acoustic primary control system and multiplex backup control system, as opposed to multiplex primary control system and Remotely Operated Vehicle [ROV] intervention as backup control system).

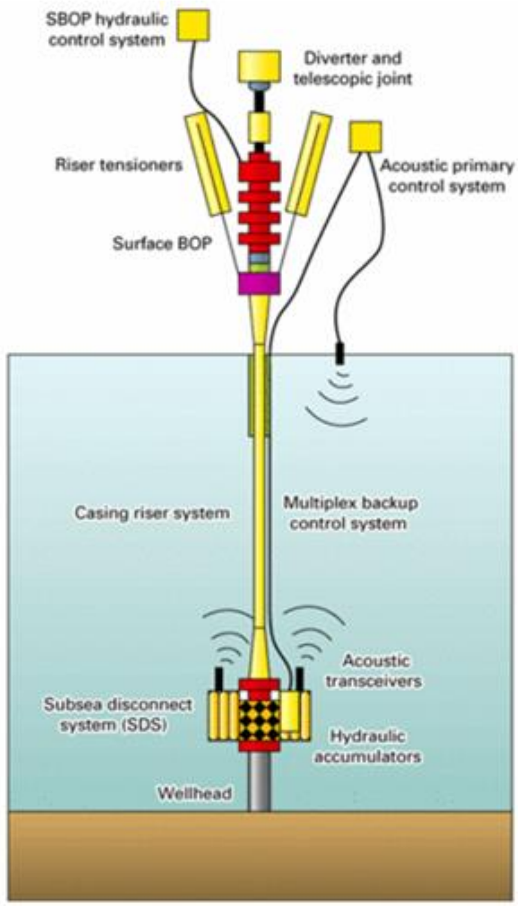

Figure 13: Example of Surface BOP with SDS. (Image Source: http\\www.ogj.com)

<u>SBOP Stack</u>

The SBOP stack is made up of a number of ram and annular preventers that are hydraulically actuated to shut in and control the wellbore. The SBOP stack is installed on top of the riser via a hydraulic riser connector. In addition, choke and kill lines from the choke and kill manifold will connect with the SBOP stack. It is pertinent to note that the choke and kill manifold is excluded from the surface BOP system as it is considered part of the Mud Circulation system. However, the SBOP stack mounted choke and kill line valves, which can be used to isolate flow through the choke and kill lines, are considered part of the surface BOP system. The configuration of the SBOP stack elements can vary depending on factors such as company preference, rated working pressure, intended functionality of the SBOP system and operating depth. The SBOP configuration assumed for the barrier model is based on a Class V surface BOP stack that could be expected for drilling operations in deep water. The following barrier elements are considered critical for the surface BOP stack to perform its intended functions:

- Annular Preventers (2)
  - There is an upper and lower annular preventer that can close and seal around the drill string
- Blind Shear Ram (1)
  - There is one blind shear ram that can shear and seal the drill string or close on open hole to seal the wellbore

- Pipe Rams (2)
  - There is an upper and lower pipe ram that can close and seal around the drill string
- SBOP Stack Mounted Choke and Kill Line Valves
  - Valves that can isolate flow to the choke and kill lines (2 per line) allowing control of the flow to the choke and kill manifold
- Riser/SBOP Connector
  - For connection of the SBOP stack to the riser

<u>SDS</u>

The SDS is made up of one pipe ram and one blind shear ram, hydraulically actuated to shut in the wellbore. The SDS is connected to the riser and the top of wellhead, via two separate hydraulic connectors (Riser/SDS and Wellhead connectors). There are no choke and kill lines connected to the SDS. The configuration of the SDS elements can vary depending on factors such as company preference, mooring system of the rig, intended functionality of the SDS system and operating depth. The SDS configuration assumed for the barrier model is based on a 'typical' SDS that could be expected for drilling operations in deep water with a moored floater. The following barrier elements are considered critical for the SDS to perform its intended functions:

- Blind Shear Ram (1)
  - There is one blind shear ram that can shear and seal the drill string or close on open hole to seal the wellbore
- Pipe Ram (1)
  - There is one pipe ram that can close around the drill string for hang-off
- Riser/SDS Connector
  - For connection of the SDS to the riser
- Wellhead Connector
  - For connection of the SDS to the wellhead

<u>SBOP Control System</u>

The control system used to actuate individual components of the SBOP stack is considered part of the SBOP system. The purpose of the control system is to provide an interface between the driller and the SBOP stack, transfer the electric signals and hydraulic fluid for actuating stack components and to report critical wellbore pressures. The control system assumed for the barrier model is based on a typical hydraulic control system. The barrier elements that are considered critical for the SBOP Control System are listed below:

- Driller's Control Panel
  - Primary control panel, which provides Operator interface with the SBOP stack
- Toolpusher's Control Panel
  - Redundant control panel with the same functions as the Driller's Control Panel
- Control Manifold

- Manifold that controls the hydraulic fluid provided to the SBOP stack valves
- Surface Accumulators
  - Consists of a series of surface accumulators used to provide hydraulic fluid to the Control Manifold
- Hydraulic Lines
  - Hydraulic lines that carry hydraulic fluid from the HPU / Surface Accumulators to the Control Manifold
- UPS
  - Provides back-up power to the control system

Note that only elements of the SBOP Control System, which are considered to have a direct impact on the SBOP stack components fulfilling their intended function, are considered. For instance, the Hydraulic Power Unit (HPU) and hydraulic supply are excluded, given that the SBOP stack components are able to actuate without the HPU assuming the accumulators are pre-charged. Similarly, rig power, which is used to provide power to the HPU pumps, is not included. Other assumptions used to develop the SBOP Control System for the model are presented in Table 17.

SDS Main Control System

The control systems used to actuate individual components of the SDS are considered part of the SDS system. The purpose of the SDS Main Control System is to provide an interface between the Operators and the SDS, transfer the electric signals and hydraulic fluid for actuating stack components and to report critical wellbore pressures. The SDS Main Control System assumed for the barrier model is based on a typical Multiplex (MUX) control system. A MUX control system is considered best practice for deep-water applications. It responds faster than a conventional hydraulic control system and is considered more reliable than an acoustic system where communication through the water column can be affected by the water depth. The barrier elements that are considered critical for the MUX Controls System are listed below:

- Driller’s Control Panel
  - Primary control panel, which provides Operator interface with the SDS
- Toolpusher’s Control Panel
  - Redundant control panel with the same functions as the Driller’s Control Panel
- Central Control Unit (CCU)
  - Redundant CCUs that log data and convey communication from the panels to the SDS through MUX Cables
- MUX Cable and Reel (blue/yellow)
  - Redundant pair of cables that transfer electric signals from the CCU to the Control Pods
- Control Pods (blue/yellow)
  - Redundant control pods that regulate hydraulic pressure and interpret electric signals to actuate SDS functions
- Rigid Conduits (blue/yellow)

- Redundant pair of hydraulic lines that carry hydraulic fluid from the HPU / Surface Accumulators to the Control Pods
- UPS (A/B redundancy)
  - Provides back-up power to the MUX control system
- Surface Accumulators
  - Consists of a series of surface accumulators used to provide hydraulic fluid to the Control Pods

Note that only elements of the MUX control system which are considered to have a direct impact on the SDS components fulfilling their intended function are considered. For instance, the HPU and hydraulic supply are excluded, given that the SDS components are able to actuate without the HPU assuming the accumulators are pre-charged. Similarly, rig power, which is used to provide power to the HPU pumps is not included. Other assumptions used to develop the SDS Main Control System for the model are presented in Table 17.

SDS Secondary Control System

The secondary control system for the SDS is provided as redundant means of control in the event that the main control system is inoperative. Types of backup control systems for subsea controls include (but are not limited to) acoustic control systems and ROV operated control systems. The SDS secondary control system for the barrier model is based on a ROV operated control system. It is important to recognize that although the ROV operated control system may be able to fulfil the critical SDS functions in place of the main control system for certain barrier critical system functions, the Operator's well control procedures/policies may dictate that it may not be practical to utilize ROV operated control systems. If this is the case, then the ROV operated control system should not be considered a barrier element for that specific barrier critical system function. The barrier elements that are considered critical for the ROV operated control system are listed below:

- ROV Pilot Station
  - Provides the interface between the ROV pilot and ROV
- ROV Umbilical Cable
  - Conveys the communication from the ROV pilot to the ROV
- ROV Control Panel
  - Provides the interface for the ROV to actuate SDS functions
- ROV Unit
  - Vehicle used to actuate SDS function
- ROV Power Unit
  - Provides the ROV with power
- Dedicated Emergency Subsea Accumulator System
  - Used to supply hydraulic fluid to the ROV for hot stabs

Note that the same emergency accumulator is assumed to be used for both ROV intervention (secondary control system) and auto shearing purposes (DMAS control system). The assumptions regarding the secondary control system are presented in greater detail in Table 17.

Emergency Control: Deadman/Autoshear (DMAS) Control System

Autoshear and deadman systems are optional safety systems that are designed to automatically shut in the wellbore during unplanned emergency events. Autoshear is a safety system designed to automatically shut in the wellbore in the event of an unintended disconnect of the riser from the SDS, whilst the deadman system is designed to shut in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. DMAS systems are usually employed for deepwater/harsh environment applications, particularly where multiplex BOP controls and dynamic positioning of the vessel are used. A DMAS system is assumed for the SBOP system barrier model for the SDS, given that these conditions align with the scenario basis defined in Scenario Description.

The configuration and sequence of events undertaken by the DMAS system is dependent on the requirements of the end user, equipment owner and manufacturer. For the barrier model, the actuation of the SDS blind shear ram is performed by four Sub Plate Mounted (SPM) valves in series, which are part of the DMAS control pod. All four of the SPM valves have to be open for the power fluid from the emergency dedicated accumulators to reach the SDS function.

One of the four SPM valves is actuated open upon manual arming of the DMAS system, which is carried out by either the Driller's or Toolpusher's panel. Once armed, a Pilot Operated Check Valve (POCV) is used to keep the SPM (arm/disarm) valve in the last actuated position allowing for power fluid to flow to the other three SPMs for loss of hydraulic and electric power. If hydraulic power is lost after the function is armed the SPM (arm/disarm) valve does not close or block the flow because of the POCV maintaining it in its last position.

In the case of loss of hydraulic power, there are hydraulic lines which are routed through a common shuttle valve supplied from the rigid conduit manifold and the hot line manifold to the Loss of Hydraulic Power (LOHP) SPM valve in the DMAS pod. If the supply from both the rigid conduit and the hotline manifold is lost (the two means of supplying hydraulic power to the blue and yellow pods) then the LOHP SPM is de-energized to its normally open position, thereby unblocking the power fluid flow to the third SPM valve.

When electric power is available, the power/command signals are continuously sent to Subsea Electronics Module A and B within each blue and yellow pod. The SEMs, based on this signal, sends a continuous hydraulic supply through a hydraulic line to the Loss of Electric Power (LOEP) SPM in the DMAS pod. These are also routed through shuttle valves from both pods. Upon loss of electric signals to all the SEMs in the pods, the hydraulic supply to the LOEP SPM is stopped, thereby de-energizing it to its normally open position unblocking the power fluid flow to the fourth SPM valve.

A final SPM valve (labelled as 'Blind Shear Ram Close SPM valve') also exists in series with the previously described three SPM valves. This Blind Shear Ram Close SPM valve is actuated open upon loss of both electric and hydraulic power. With the opening of this SPM valve, the power fluid from the dedicated emergency subsea accumulators can reach the blind shear ram BOP function through the four unblocked SPM valves.

Often, the Blind Shear Ram Close SPM valve is also configured as part of a time delay hydraulic circuit as defined in the end user's requirements/specification, especially in cases where there are multiple BOP stack functions (e.g. two blind shear rams or one blind shear and a casing shear ram) that need to be actuated as part of the DMAS sequence.

When there is a disconnect of the LMRP connector from the lower BOP stack due to physical separation, the hydraulic lines connected to the DMAS pod SPMs are disconnected, thereby leading to the autoshear function.

The barrier elements that are considered critical for the DMAS system are listed below:

- LOEP SPM Valve
    - 'Fail safe' SPM valve that operates upon loss of electric power
- LOHP Valve
    - 'Fail safe' SPM valve that operates upon loss of hydraulic power
- Blind Shear Ram Close SPM valve
    - SPM valve that actuates open upon loss of both hydraulic and electric power
- Pilot Operated Check Valve
    - Check valve used to make the SPM (armed) fail in its last position
- Dedicated Emergency Subsea Accumulator System
    - Rapid discharge subsea accumulator that provides hydraulic fluid to the shear ram

The control panels, CCU, MUX cables and SPM (arm/disarm) valve are used to arm the DMAS system. However, this occurs well in advance to actually requiring the DMAS system. Typical well control policies/procedures demand that the DMAS system is armed while the SDS is latched onto the wellhead. Therefore, in the event that the DMAS system is required, the system should already be armed. As a result, the topside control panels, CCU, MUX cables and SPM (arm/disarm) valve are not considered barrier critical elements for the DMAS system. The assumptions used to define the barrier element are presented in Table 17.

6. Barrier Model for Surface BOP and Subsea Disconnect System

6.1 Barrier Model Scope (Interfaces and Barrier Elements) and Key Assumptions

6.1.1 Barrier Critical System Functions

The surface BOP and the Subsea Disconnect System (SDS) are preventive barriers that provide means to shut in and control the well bore. The following Barrier Critical System Functions (BCSFs) are identified as being necessary for the surface BOP / SDS to perform the barrier function:

Surface BOP

- Maintain SBOP Connection (BCSF 1)
- Close and Seal on Drill Pipe and Allow Circulation (BCSF 2)
- Close and Seal on Open Hole and Allow Volumetric Well Control Operations (BCSF 3)
- Shear Drill Pipe or Tubing and Seal Wellbore – Commanded Closure (BCSF 4)
- Strip Drill String (BCSF 5)

Subsea Disconnect System (SDS)

- Maintain SDS Connection (BCSF 6)
- Shear Drill Pipe or Tubing and Seal Wellbore – Auto-Shear during Emergency Situation (BCSF 7)
- Shear Drill Pipe or Tubing and Seal Wellbore – Emergency Disconnect Sequence (BCSF 8)
- Hang-Off Drill Pipe (BCSF 9)

These BCSFs are derived from the requirements of API S53 and FMECA studies previously performed on the subsea BOP as part of another BSEE project. Details regarding each of the BCSFs are presented below. The contents of this section should be read in conjunction to the Barrier Model (presented in Section 6.2).

<u>Maintain SBOP Connection (BCSF 1)</u>

SBOP connector is locked and sealed to establish proper connection between riser and SBOP. When proper connection is established, hydraulic pressure is no longer required to maintain connection. Connections must be maintained during the all operation. The main control system is used to activate the connectors.

<u>Close and Seal on Drill Pipe and Allow Circulation (BCSF 2)</u>

Annular BOP(s) or Pipe Ram(s) closes and seals the annular space between riser and drill string. The Annular BOP(s) must maintain its sealing pressure to remain sealed, whereas the Pipe Ram(s) closes and seals by engaging a ram lock when closed. When the annular space is sealed, SBOP Stack Mounted

Choke and Kill Line Valves are operated to allow circulation of the well via the connected choke and kill lines. The main control system can be used to activate the Annular Preventer(s), Pipe Ram(s) and the BOP Stack Mounted Choke and Kill Line Valves on demand. In case of the Pipe Ram(s), activation by ROV intervention (secondary control system) is also possible if needed.

Close and Seal on Open Hole and Allow Volumetric Well Control Operations (BCSF 3)

When no drill string is in the riser, Annular BOP(s) or Blind Shear Ram closes and seals the open hole. The Annular BOP(s) must maintain its sealing pressure to remain sealed, whereas the Blind Shear Ram closes and seals by engaging a ram lock when closed. When the open hole is sealed, SBOP Stack Mounted Choke and Kill Line Valves are operated to allow volumetric well control operations via the choke and kill lines. The Blind Shear Rams may be activated by the main control system or secondary control system (if needed).

Shear Drill Pipe or Tubing and Seal Wellbore – Commanded Closure (BCSF 4)

The Blind Shear Ram closes and shears the drill pipe or tubing and seals the wellbore. The ram lock is also engaged as part of the closing function. The operation is initiated on demand from the driller's or tool pusher's panel and can be performed by either the primary (hydraulic control system) or secondary control system (ROV operated control).

Strip Drill String (BCSF 5)

Annular BOP(s) closes and seals the annular space between riser and drill string. The Annular BOP(s) must maintain its sealing pressure to remain sealed while slightly relaxing the elastomeric sealing element to allow for stripping with minimal wear. The drill string can then be stripped through the Annular BOP(s) to regain control of the well. The Annular BOP is assumed to only be operated, via the Main Control System.

Maintain SDS Connection (BCSF 6)

On landing, the SDS connectors are locked and sealed to establish proper connection between riser/SDS and SDS/wellhead, respectively. When proper connection is established, hydraulic pressure is no longer required to maintain connection. Connections must be maintained during all operation except the emergency disconnect scenario. The main control system is used to activate the connectors.

Shear Drill Pipe or Tubing and Seal Wellbore – Auto-Shear during Emergency Situation (BCSF 7)

The Blind Shear Ram closes and shears the drill pipe or tubing and seals the wellbore. The ram lock is also engaged as part of the closing function. The activation of the Blind Shear Rams is by the DMAS control system which must be armed by Operator, while the SDS is latched onto the wellhead. The operation is then automatically initiated upon either of the following scenarios:

- Loss of hydraulic and electric power to DMAS control pod
- Disconnection of riser from SDS

The DMAS control pod will initiate actuation of the SDS Blind Shear Ram, via four SPM valves in series. All four of the SPM valves have to be open for the power fluid from the emergency dedicated accumulators to reach the SDS function, as discussed in Section 5.1.

Shear Drill Pipe or Tubing and Seal Wellbore – Emergency Disconnect Sequence (BCSF 8)

The Blind Shear Ram closes and shears the drill pipe or tubing and seals the wellbore. The ram lock is also engaged as part of the closing function. Subsequently, the Riser/SDS Connector unlatches, disconnecting the riser from the SDS. The sequence is automatic when initiated and must be activated by an Operator, via the Main Control System.

Hang-Off Drill Pipe (BCSF 9)

The Pipe Ram closes on the drill pipe, engaging a ram lock when closed. This allows the weight of the Bottom Hole Assembly (BHA) to be hung-off by lowering the nearest tool joint of the drill string onto the closed ram. The Pipe Ram can be closed and locked both via the SDS Main Control System and by ROV intervention.

6.1.2 Assumptions

Assumptions were made in order to develop the model and reflect what is considered a ‘typical’ surface BOP system. It should be noted that this is an example scenario developed to illustrate how the barrier model template can be applied to a select surface BOP with SDS and should not be considered as representative of all surface BOP/SDS configurations. The barrier model has been developed by the project team from ABS Consulting and verified through a review workshop with industry SMEs and BSEE personnel.

For the purpose of this example, the main assumptions made regarding the barrier elements are described in Table 17.

Table 17 – Surface BOP with SDS Scenario Assumptions – Barrier Elements

Assumption	Barrier Element
• At a minimum, the barrier critical systems (collectively or alone) must perform their intended function in order to realize the function “Shut in well and Control Wellbore”. • Control System will be responsible for actuating the component of the SBOP stack/SDS by providing electric power, hydraulic supply and managing communication signal to and from components of SBOP/SDS. • The SBOP/SDS is modeled in detail according to the BOP minimum functionality in response to the overall barrier function. • Rig power is considered to be outside of the SBOP/SDS boundary definition. Power supplies have been included as attribute(s) for UPS (dependencies to other systems). However, electrical power is considered to be available during all operations. • The individual barrier critical system/elements may also provide certain shared functionality (interdependencies) that are being used across multiple critical system/elements.	All systems
• Pipe Rams and Blind Shear Rams have automatic locking mechanism and will close and lock as part of the “close” function. • Ram lock mechanism only needs to be energized to activate the lock and does not require power to remain locked.	Pipe Ram, Blind Shear Ram [SBOP and SDS]

Assumption	Barrier Element
• Annular BOP is Complete Shut Off (CSO) type and capable of sealing on an open hole.	Annular BOP
• Sealing is inherent of the hydraulic connector latch and connect function (e.g. SBOP Stack-Wellhead Connector).	Riser-SBOP Connector, Riser-SDS Connector, Wellhead Connector
• The CCU has crossover communications to both the Blue and Yellow Pods.	CCU
• Choke and Kill Manifold has been excluded from the surface BOP system, it is considered part of the Mud Circulation system.	Choke and Kill Manifold
• There are two independent rigid conduits used to supply hydraulic power fluid to the dedicated SDS control pods (i.e., one to the blue pod and one to the yellow pod)	Rigid Conduits
• The surface accumulators are charged and available to supply power fluid to perform the SBOP/SDS functions on demand. The HPU will not be required immediately to perform the function, but only to recharge the surface accumulators at the pre-defined pressure set point. • The surface accumulators provide hydraulic power to the SBOP stack functions and to the Pipe Ram on the SDS.	Surface Accumulators
• The SBOP control system is assumed to be a standard hydraulic control system.	SBOP Control System
• The primary SDS control system is assumed to be a standard MUX system. • The primary SDS control system is assumed to have redundant UPS supply to each control pod (blue/yellow). • The Emergency Disconnect Sequence is assumed to be initiated only by the Main Control System and not the ROV operated control system	SDS Main Control System
• The secondary SDS control system is assumed to be a ROV operated control system. • The ROV is capable of unlatching the Riser-SDS Connector, but will not be used in an EDS situation.	SDS Secondary Control System
• The Dedicated Emergency Subsea Accumulator System (DESAS) is shared and able to provide hydraulic power fluid to both the DMAS system and the ROV operated control system. • The DESAS provides hydraulic power only to the Blind Shear Ram on the SDS, whereas the Pipe Ram on the SDS is not supplied from the DESAS.	Dedicated Emergency Subsea Accumulator System
• ROV is fitted with a back-up battery supply.	ROV Power Unit
• The control panels, CCU and MUX cables are not considered for the DMAS operation, as the DMAS system is armed, via the Driller's Control panel, immediately after the SDS is latched on the wellhead. • Hydraulic Power Unit, Rigid Conduit and Hotlines will not be required for DMAS operation, as accumulators are charged and ready to perform their function. • Actuation of the blind shear rams requires the SPM valves in the DMAS control pod to actuate. The POCV needs to function to maintain the open position of the SPM (armed) valve during failure of hydraulics.	DMAS System
• The DMAS control pods are assumed to not have any back-up power supply.	DMAS Pod
• The Toolpusher's Control Panel is assumed to have the same functionality as the Driller's Control Panel.	Toolpusher's Control Panel

6.2 Barrier Model

The following figures show the developed barrier model for the surface BOP with SDS.

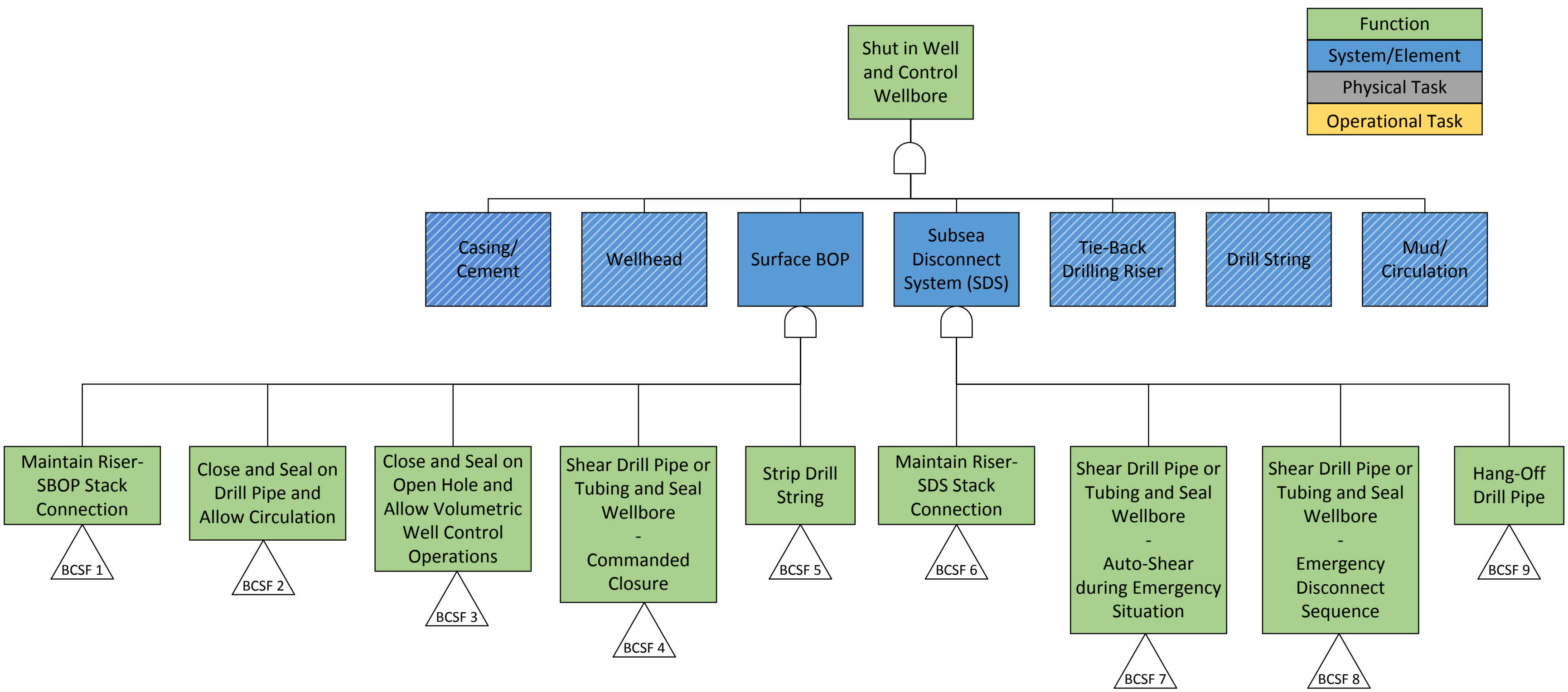

Figure 14: Barrier function, Barrier Critical Systems and Barrier Critical System Functions

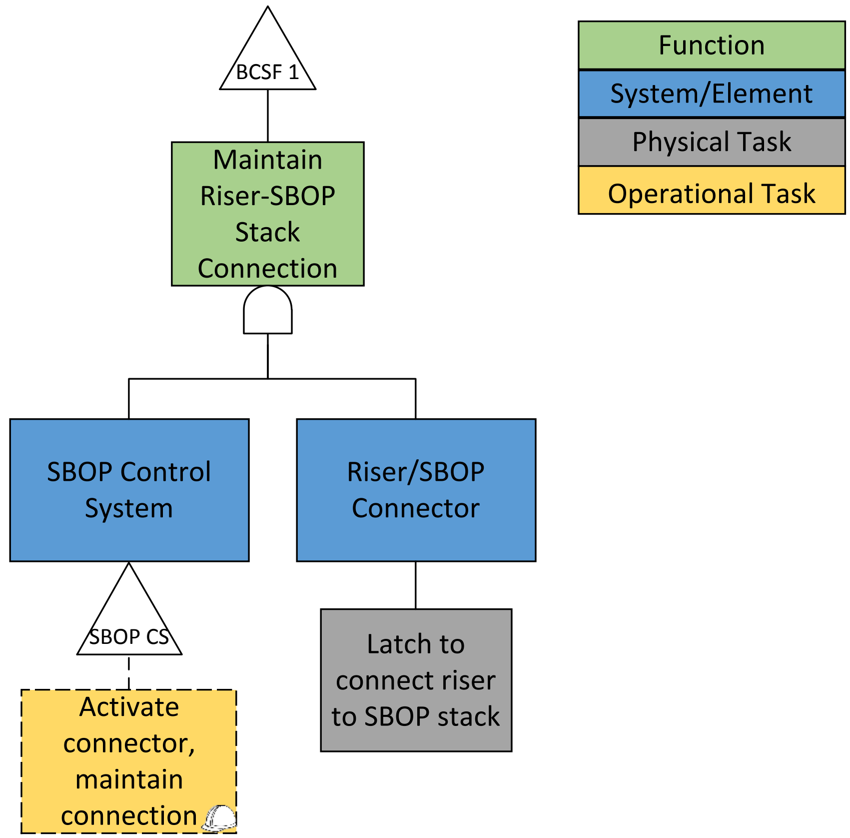

Figure 15: Barrier Critical System Function 1 – Maintain SBOP Connection

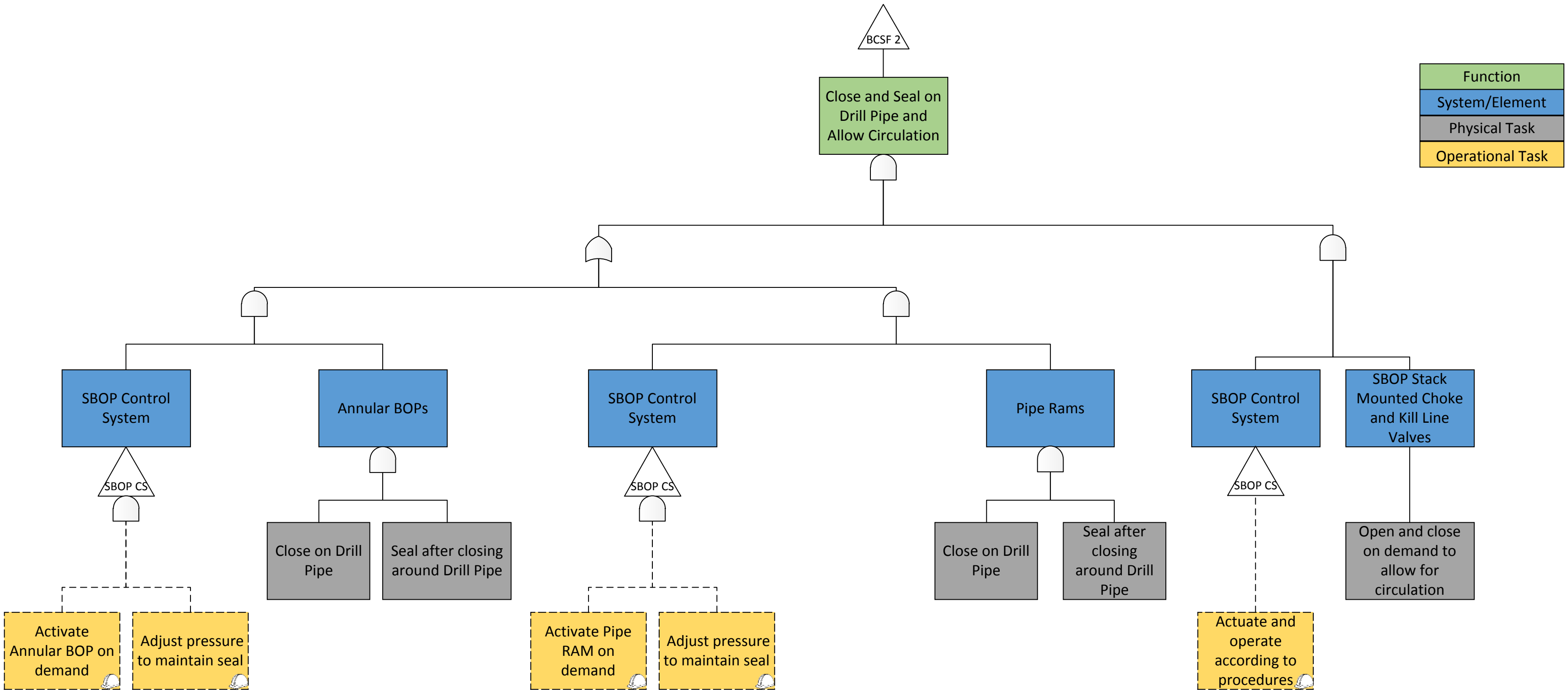

Figure 16: Barrier Critical System Function 2 – Close and Seal on Drill Pipe and Allow Circulation

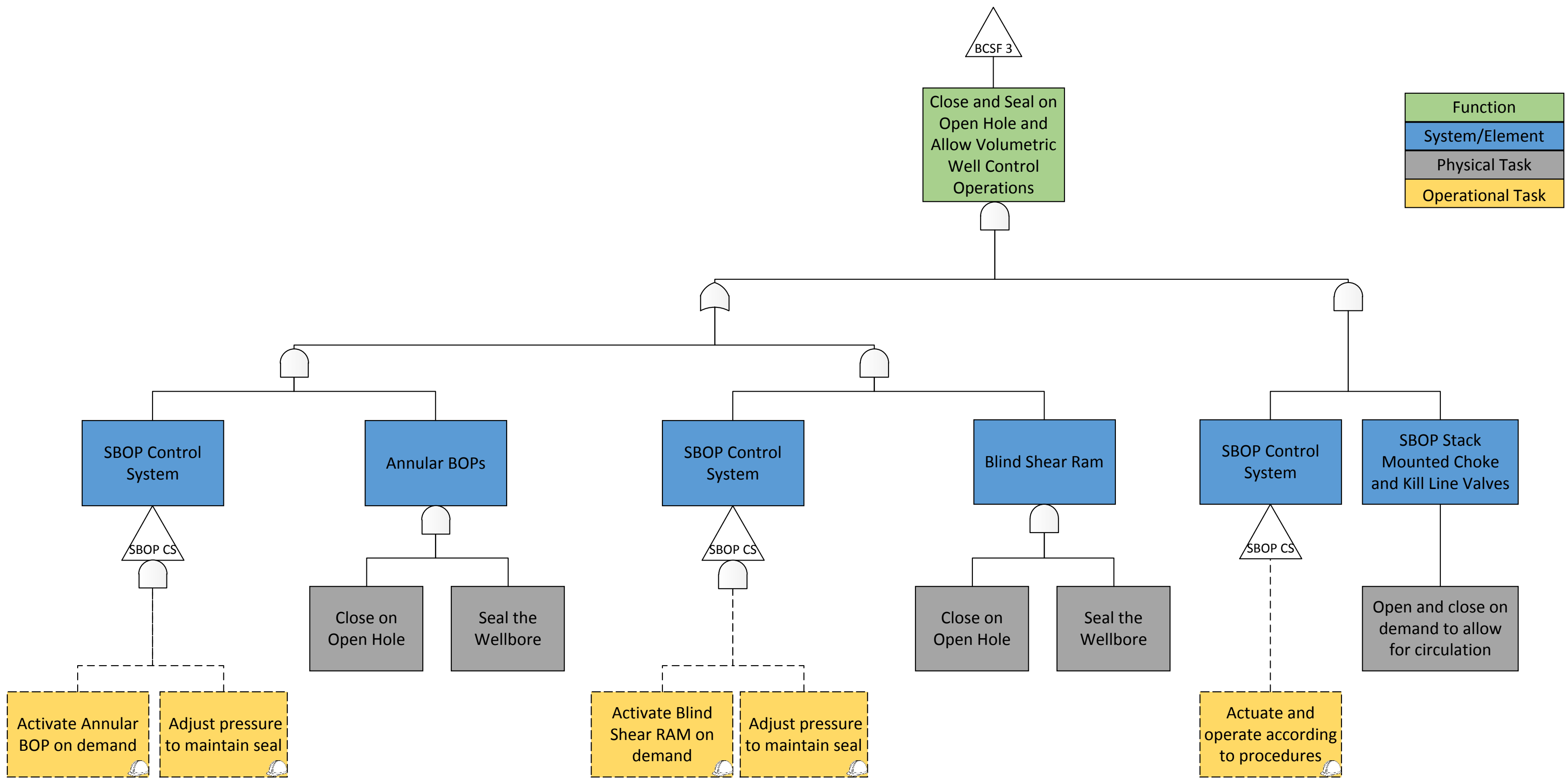

Figure 17: Barrier Critical System Function 3 – Close and Seal on Open Hole and Allow Volumetric Well Control Operations

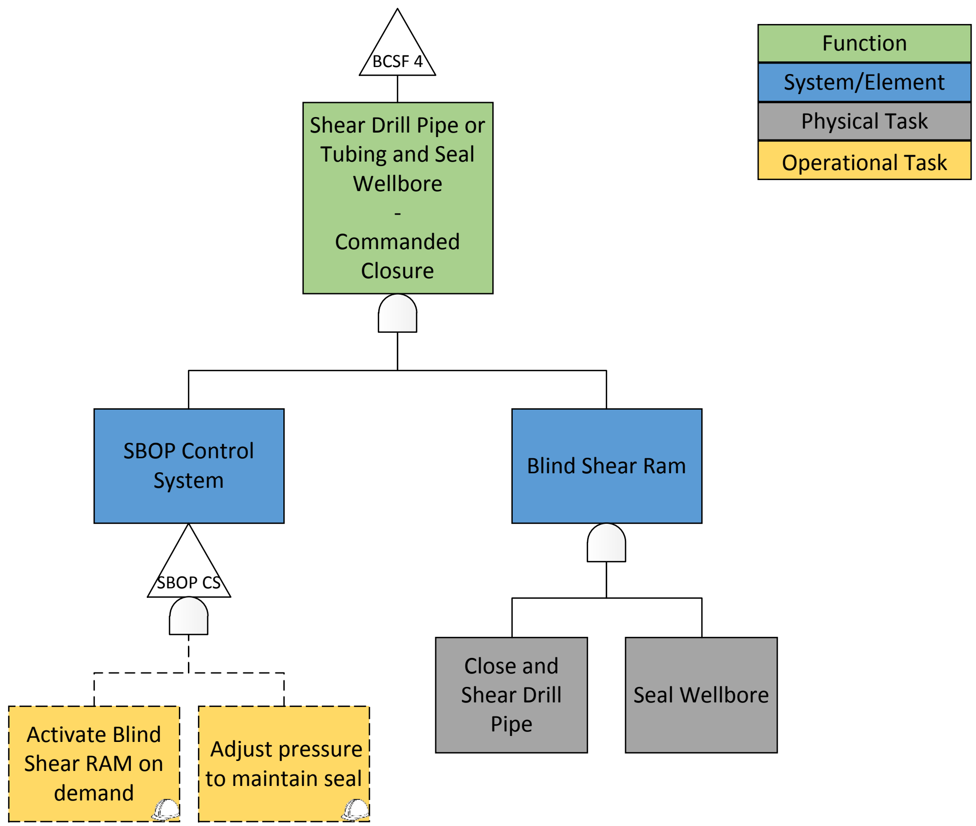

Figure 18: Barrier Critical System Function 4 – Shear Drill Pipe or Tubing and Seal Wellbore – Commanded Closure

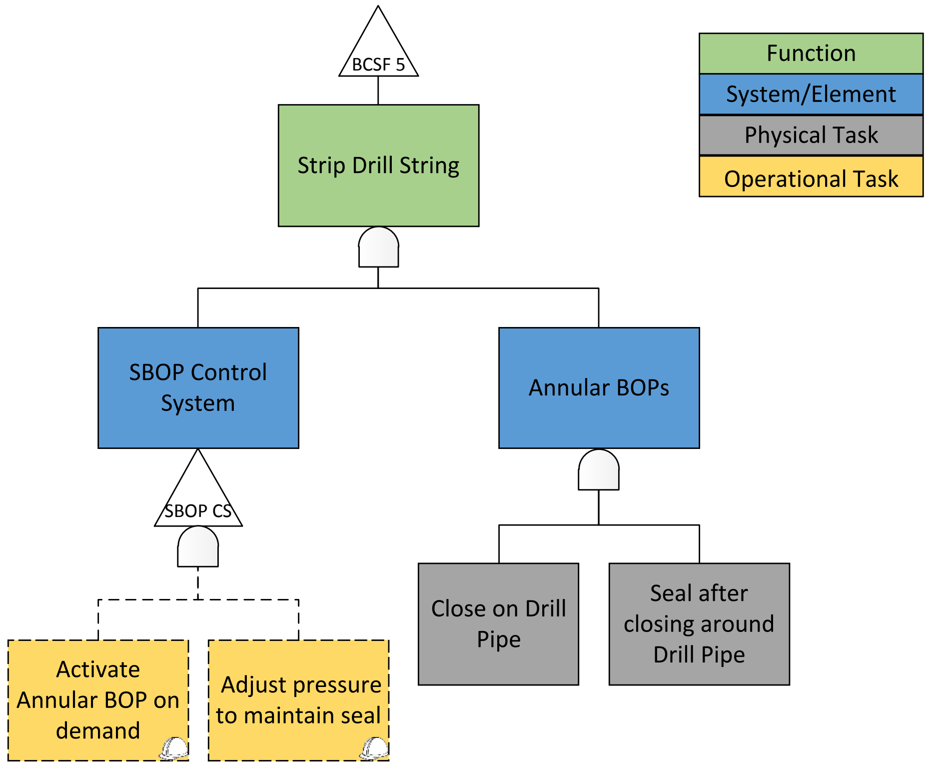

Figure 19: Barrier Critical System Function 5 – Strip Drill String

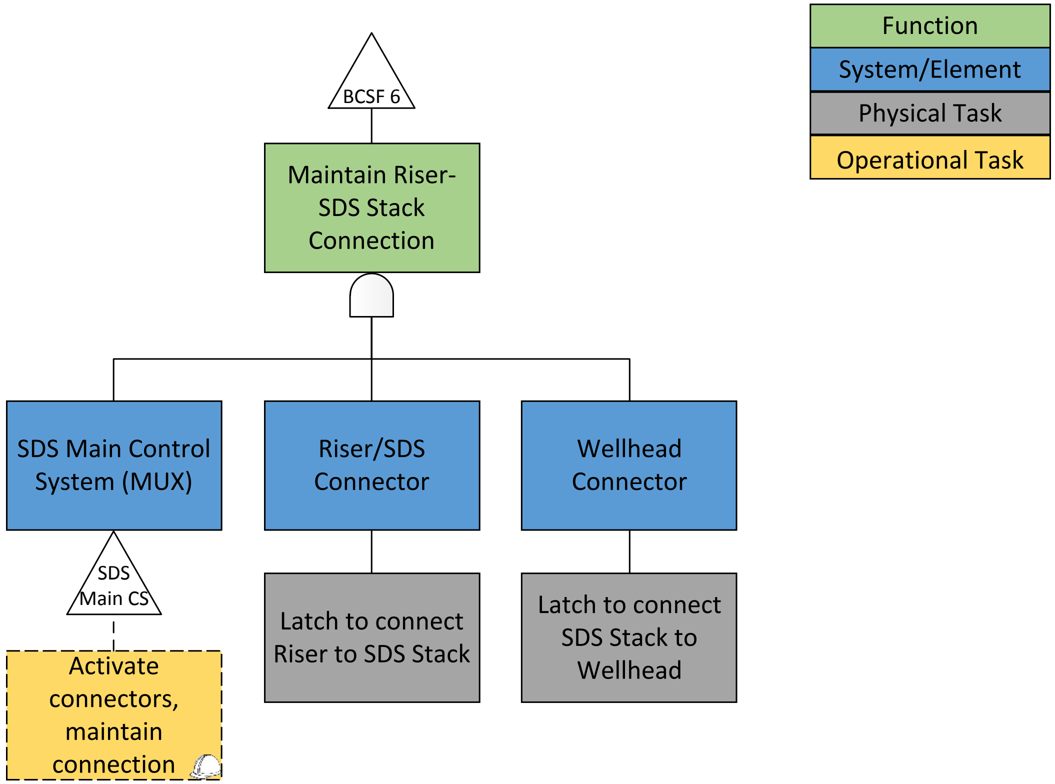

Figure 20: Barrier Critical System Function 6 – Maintain SDS Connection

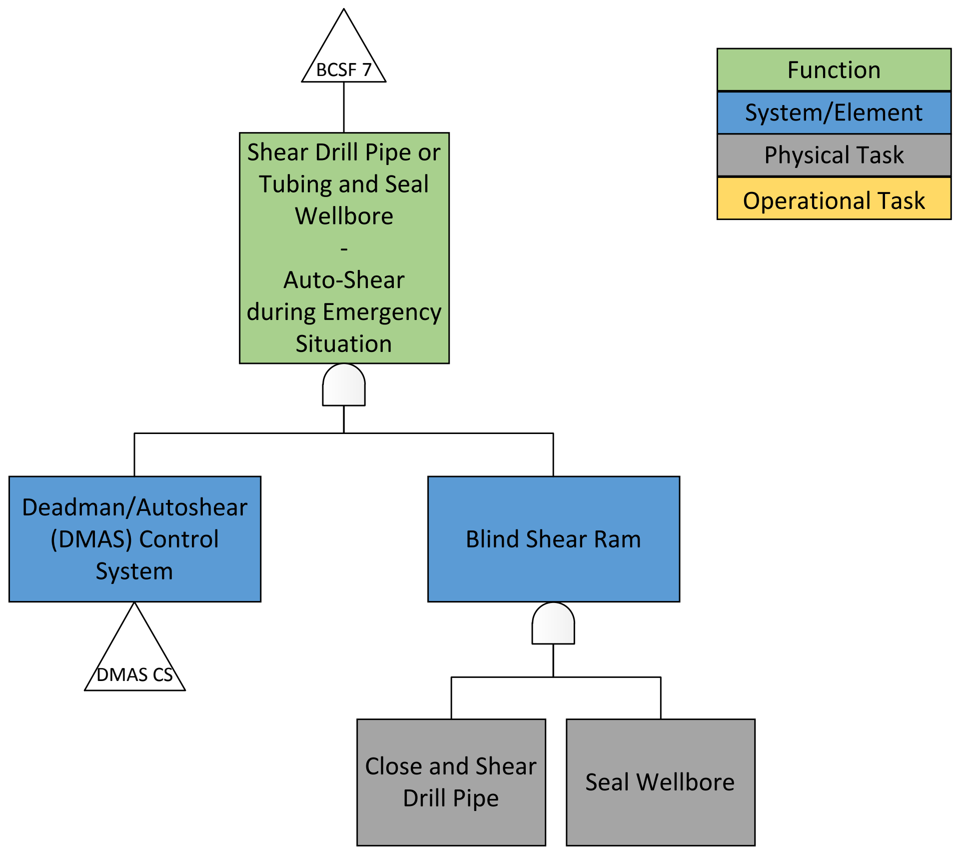

Figure 21: Barrier Critical System Function 7 – Shear Drill Pipe or Tubing and Seal Wellbore – AutoShear during Emergency Situation

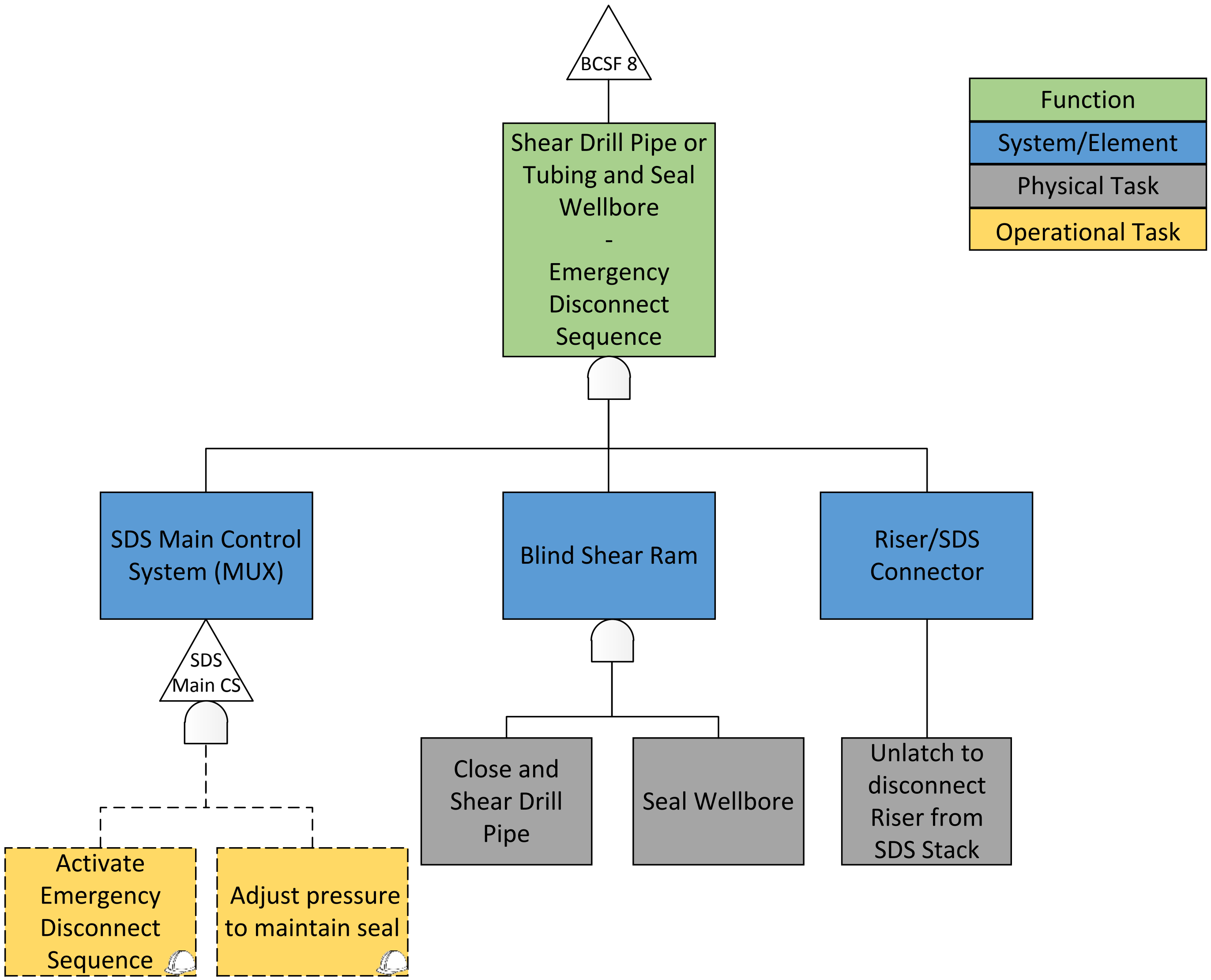

Figure 22: Barrier Critical System Function 8 – Shear Drill Pipe or Tubing and Seal Wellbore – Emergency Disconnect Sequence

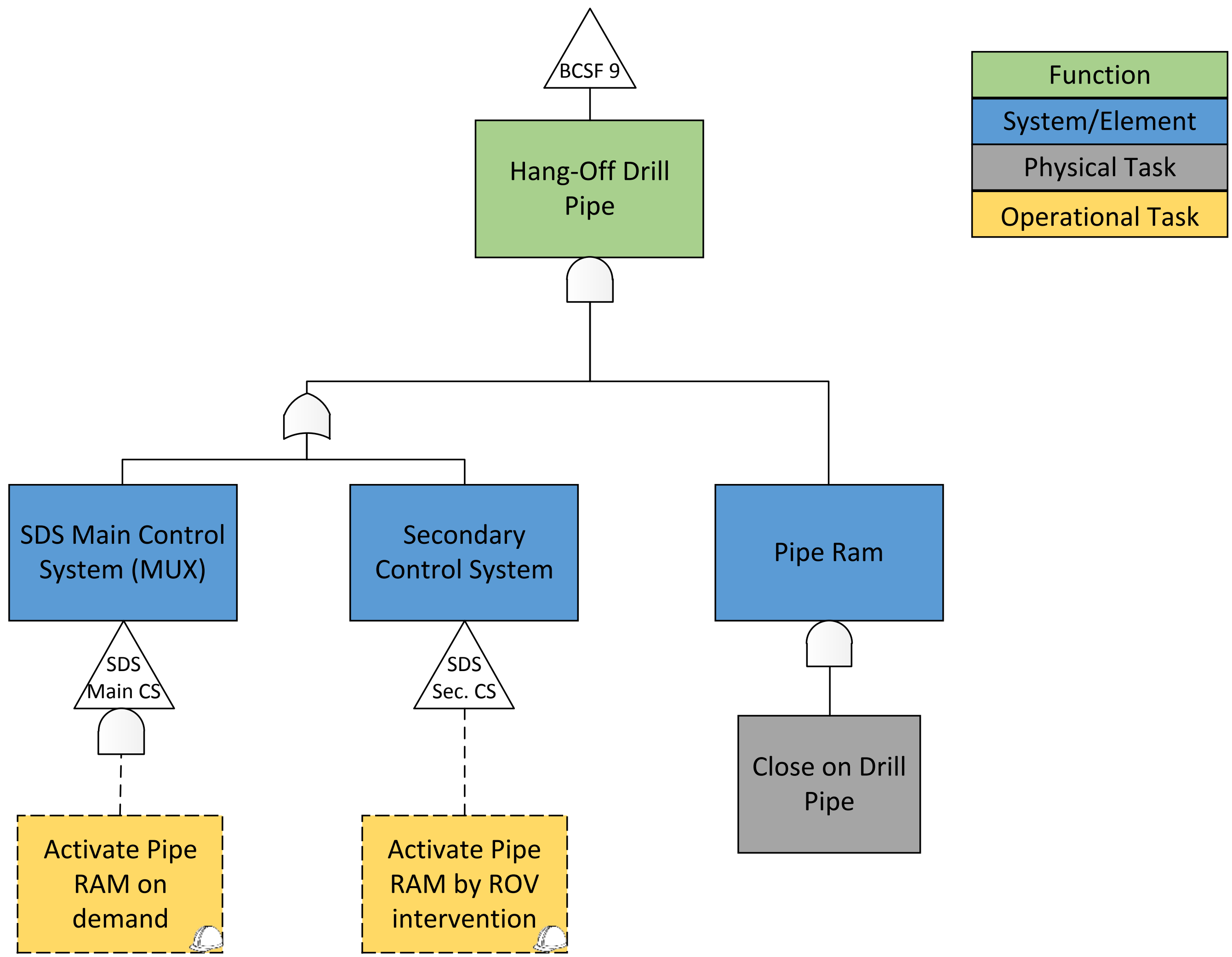

Figure 23: Barrier Critical System Function 9 – Hang-Off Drill Pipe

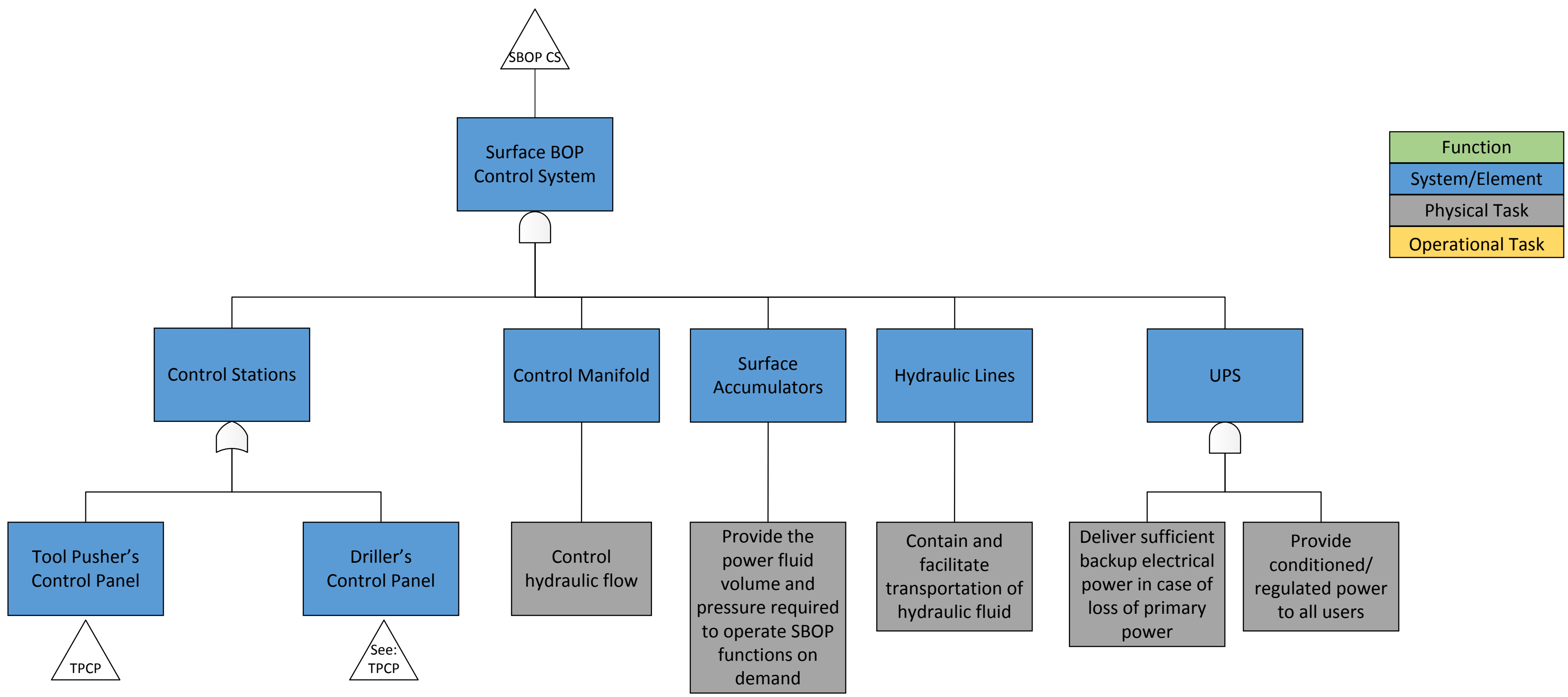

Figure 24: SBOP Control System (Hydraulic) – Part 1

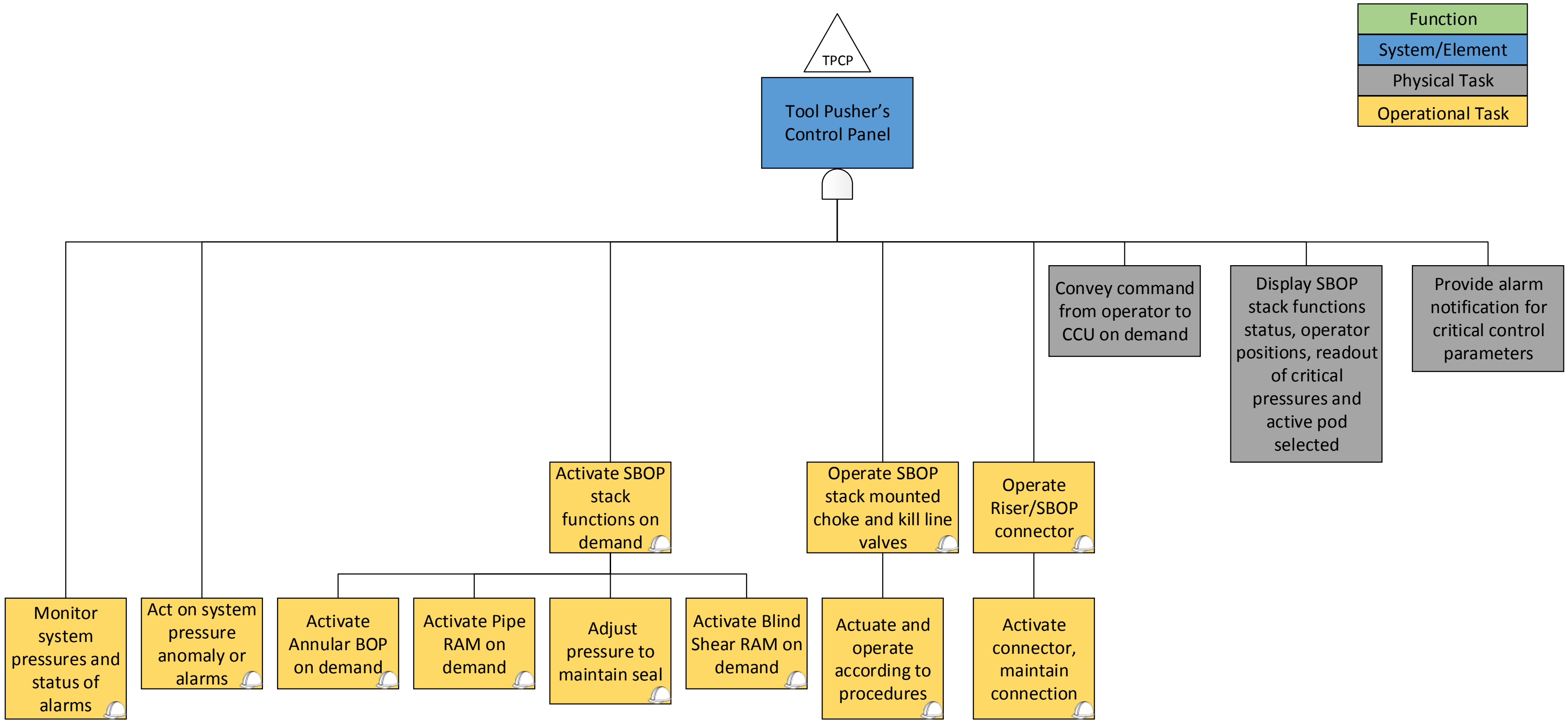

Figure 25: SBOP Control System (Hydraulic) – Part 2

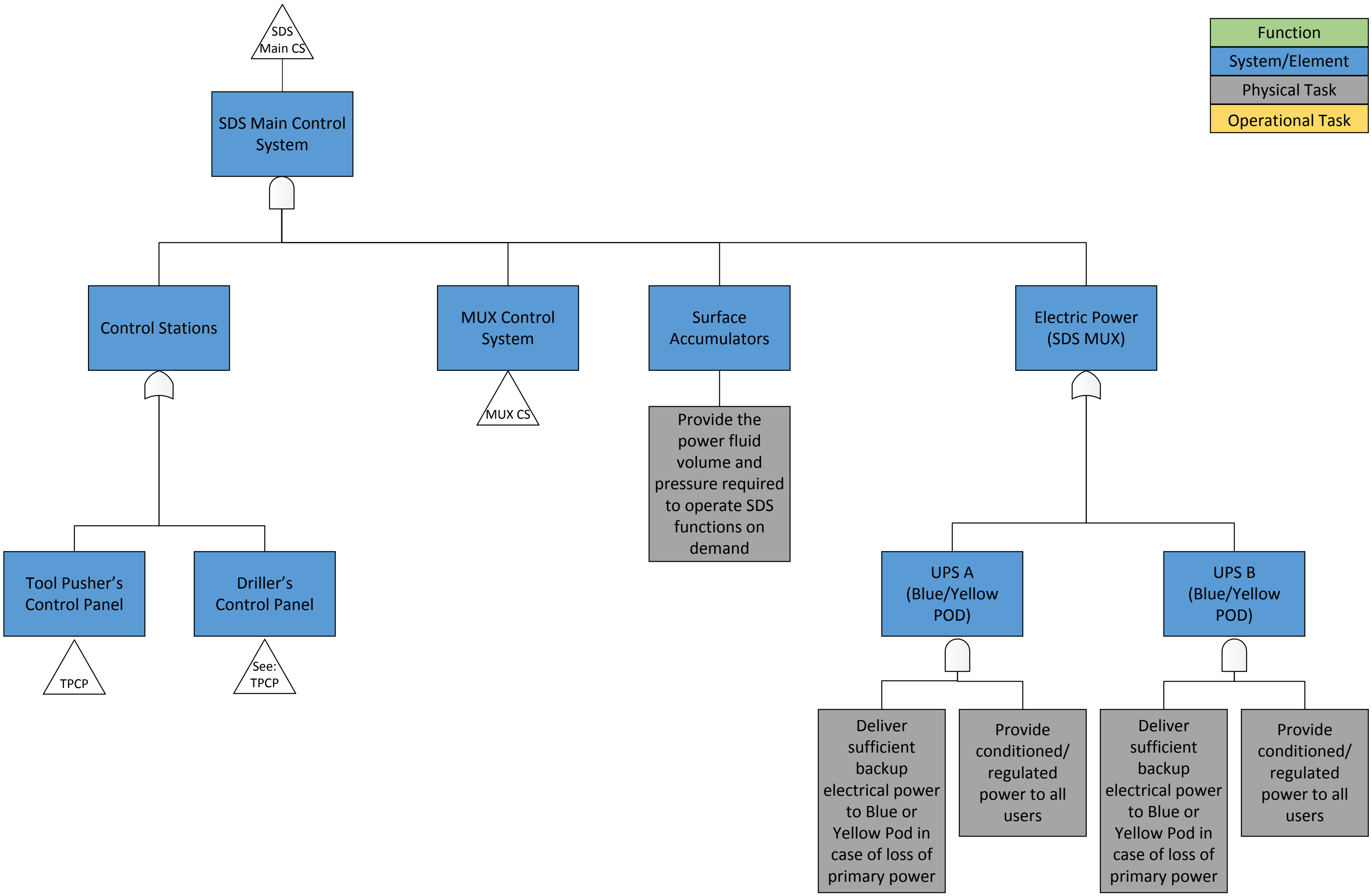

Figure 26: SDS Main Control System (MUX) – Part 1

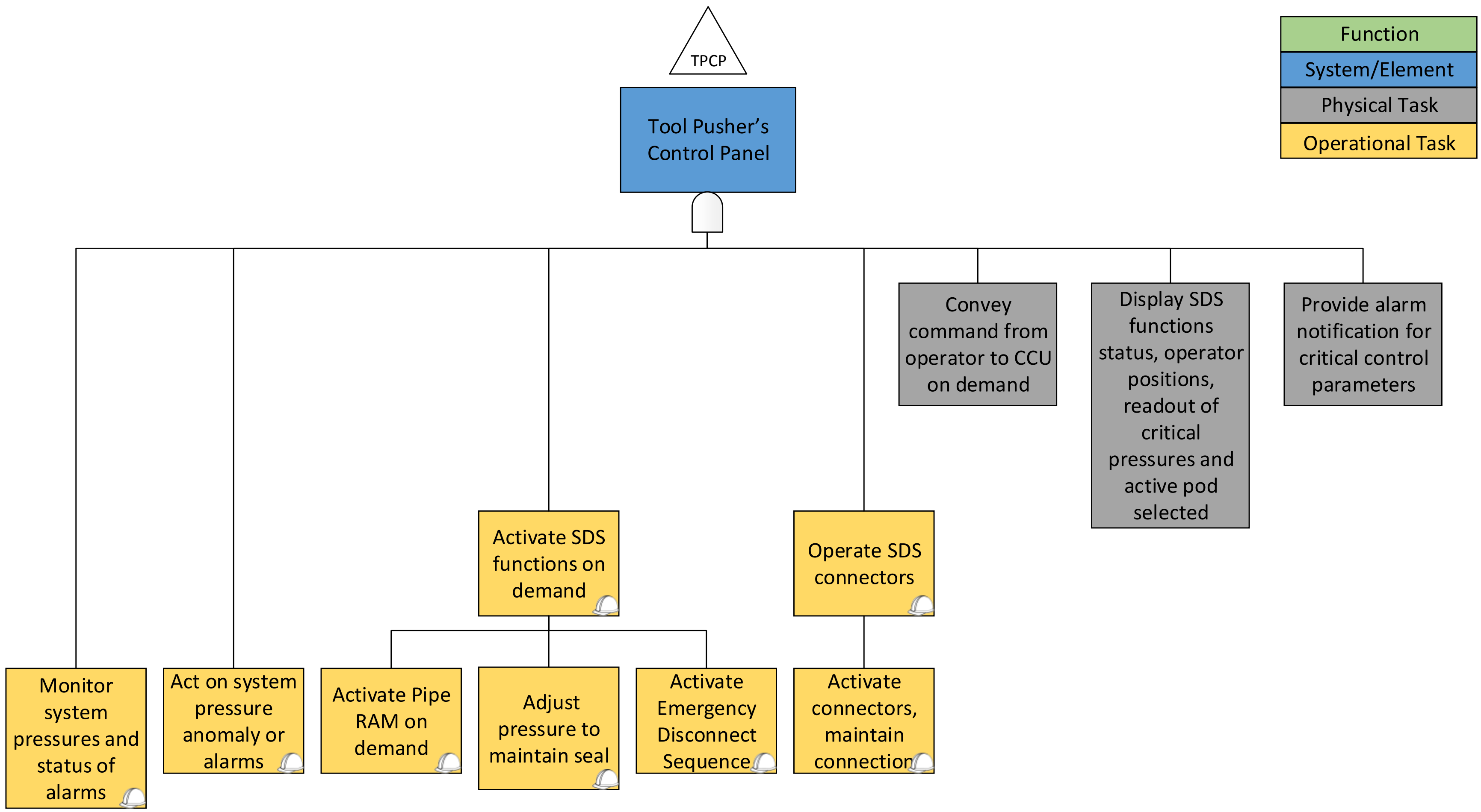

Figure 27: SDS Main Control System (MUX) – Part 2

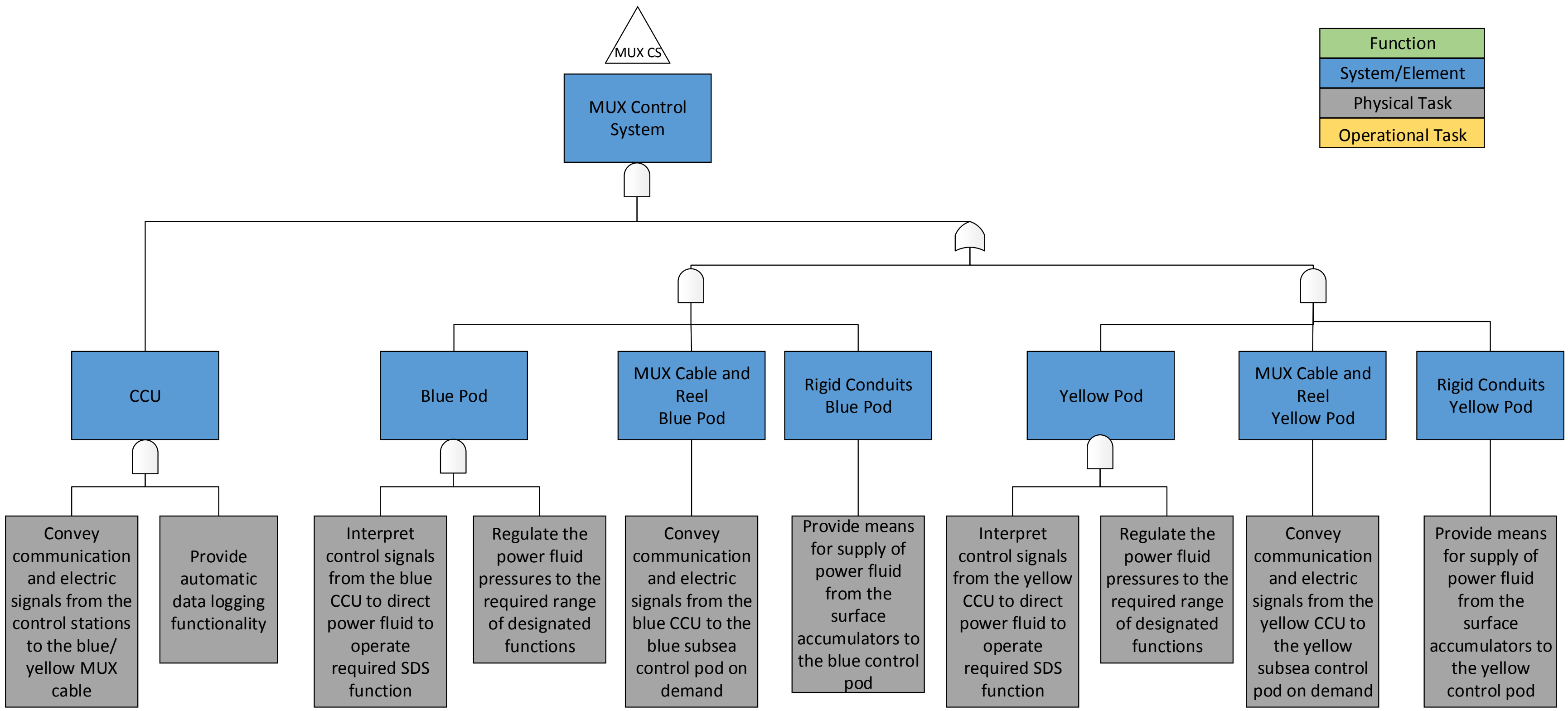

Figure 28: SDS Main Control System (MUX) – Part 3

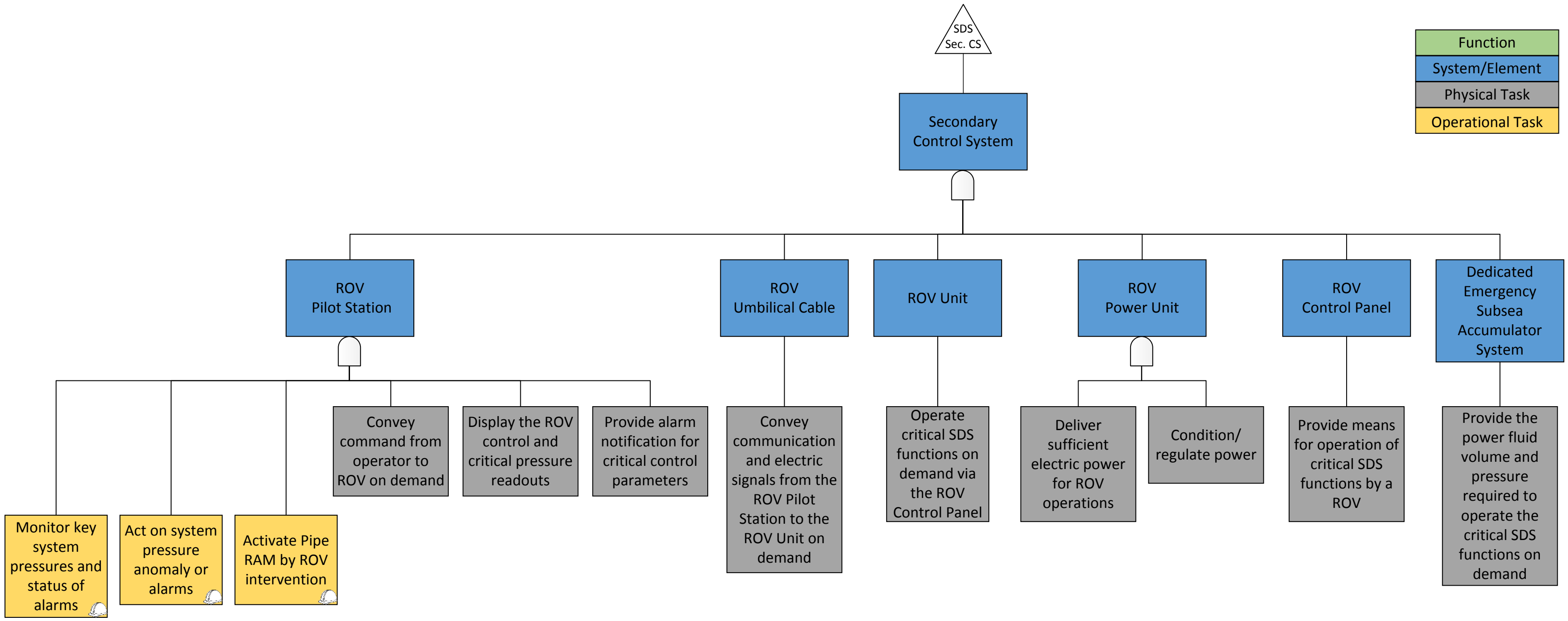

Figure 29: SDS Secondary Control System (ROV)

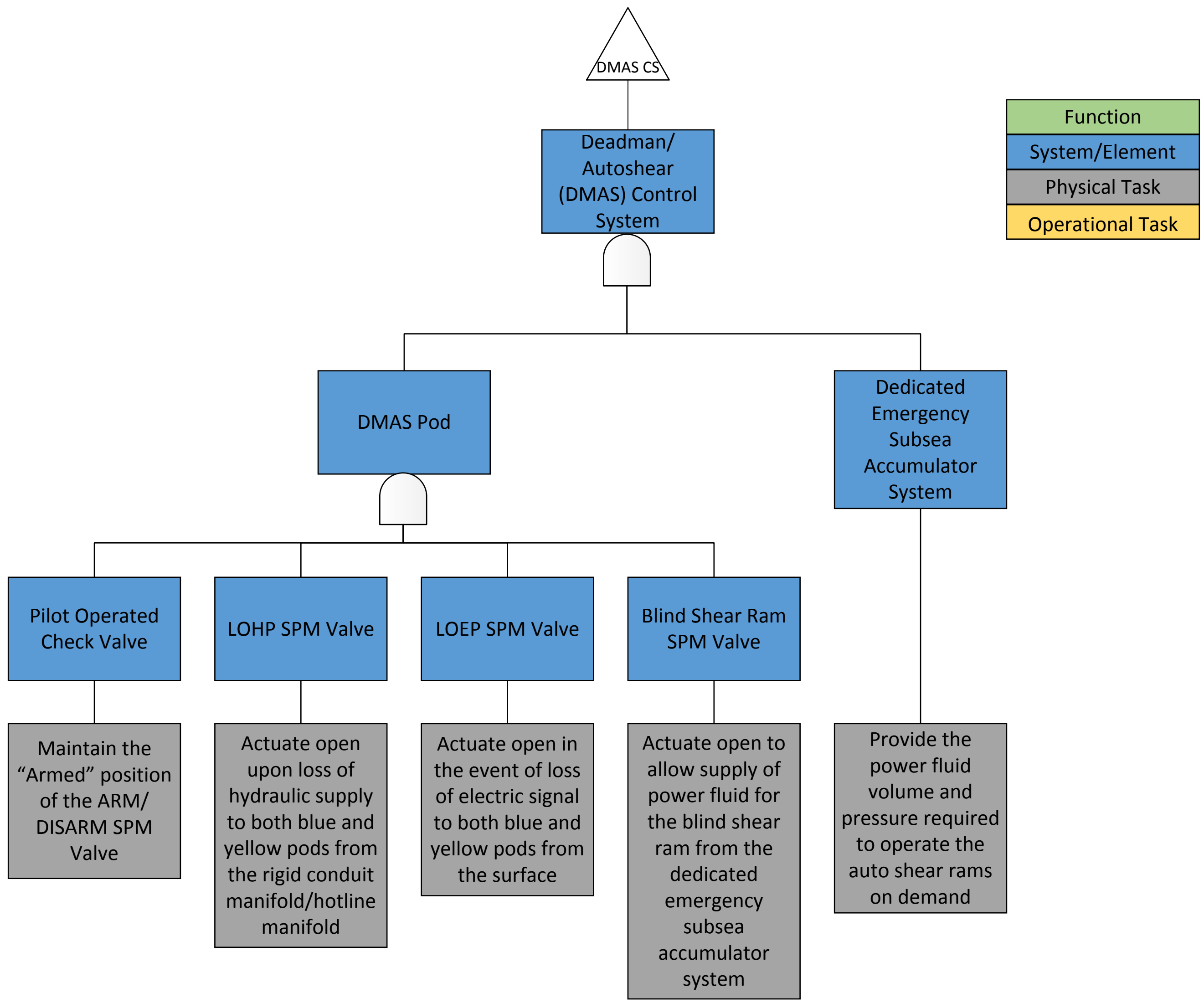

Figure 30: DMAS Control System

ABS Consulting

7. Barrier Element Attribute Checklist

Checklists highlighting attributes and related success criteria for the barrier elements have been developed to ensure that they can perform the required physical/operational task(s) to meet their intended barrier critical system function(s). The checklists have been developed as MS Excel workbooks. Within each checklist, the attributes influencing the performance of the barrier elements are structured into three tiers:

- Tier I – Covers the life cycle phases that need to be assessed
  - Design;
  - Fabrication and Testing;
  - Installation and Commissioning;
  - Operation and Maintenance;
  - Decommissioning and Removal.

These are indicated by the worksheet labels

- Tier II – Specific aspects that are required to be assessed as part of each lifecycle phase.
  As an example, corresponding to the Tier I Design worksheet, there are four Tier II attributes indicated by headers in green with each worksheet:
  - 1-1 Design Parameters
  - 1-2 Interactions/Interdependencies
  - 1-3 Layout
  - 1-4 Material
- Tier III – Provides specific detail and consideration for the BSEE reviewer to assess and validate.
  These are developed in rows under each corresponding Tier II header.

It is important to note that the success attributes provided for the barrier elements are **only examples** to illustrate the development of typical attributes based on available design standards/codes and **should not** be interpreted as prescriptive requirements to be complied with. For each proposed new technology attributes will have to be developed based on the barrier model by the Operator in conjunction with relevant parties such as the equipment manufacturers.

Table 18 summarizes the barrier elements and the attribute checklists developed for the SBOP with SDS scenario. Each barrier element checklist developed is provided as an individual MS Excel workbook, which can be accessed by clicking on the icon within the table.

Table 18 – Barrier Element Attribute Checklists

Barrier Element	Checklist Provided? (Y/N)	Checklist (Double Click to open in MS Excel)
SBOP Stack		
Annular BOP	Y	Barrier_Checklist_SBOP_Model_Annula
Pipe Ram	Y	Barrier_Checklist_Surface_BOP_Pipe_Ra
Blind Shear Ram	Y	Barrier_Checklist_SBOP_Blind_Shear_Ra
SBOP Stack Mounted Choke and Kill Line Valves	Y	Barrier Checklist_SBOPChol
Riser/SBOP Connector	N	
SDS		
Pipe Ram	Y	Barrier_Checklist_SDS_Pipe_Ram QA Dc
Blind Shear Ram	Y	Barrier_Checklist_SDS_Blind_Shear_Rar
Riser/SDS Connector	Y	Barrier Checklist_SDS_Riser
Wellhead Connector	Y	Barrier Checklist_SBOP Moc
SBOP Control System		
Driller's Control Panel	N	
Tool Pusher's Control Panel	N	
Control Manifold	N	
Surface Accumulators**	Y	Barrier_Checklist_SBOP_Surface Accum:
Hydraulic Lines	N	
UPS	N	
SDS Main Control System		

Barrier Element	Checklist Provided? (Y/N)	Checklist (Double Click to open in MS Excel)
Driller’s Control Panel	N	
Tool Pusher’s Control Panel	N	
CCU	Y	Barrier Checklist_SDS_CCU
Blue Pod	Y	Barrier Checklist_SDS_B&Y(
Yellow Pod	N	See Blue Pod above
MUX Cable and Reel (Blue Pod)	Y	Barrier Checklist_SBOP_SDS
MUX Cable and Reel (Yellow Pod)	N	See Blue Pod above
Rigid Conduits (Blue Pod)	N	
Rigid Conduits (Yellow Pod)	N	
Surface Accumulators**	Y	Barrier_Checklist_SBOP_Surface Accum
UPS A (Blue/Yellow Pod)	N	
UPS B (Blue/Yellow Pod)	N	
SDS Secondary Control System		
ROV Power Unit	N	
ROV Pilot Station	N	
ROV Control Panel	N	
ROV Umbilical Cable	N	
ROV Unit	N	
Dedicated Emergency Subsea Accumulator System*	Y	Barrier Checklist_SDS_Dedi
DMAS System		
LOEP SPM Valve	N	
LOHP SPM Valve	N	
Blind Shear Ram Close SPM Valve	N	
Pilot Operated Check Valve	N	
Dedicated Emergency Subsea Accumulator System*	Y	Barrier Checklist_SDS_Dedi

*Note: The Dedicated Emergency Subsea Accumulator System is shared for both the SDS Secondary Control System and the DMAS System.

**Note: The Surface Accumulators are shared for the SBOP stack functions and the SDS Pipe Ram.

8. References

i API, "Blowout Prevention Equipment – Systems for Drilling Wells", Fourth edition, Nov. 2012

ii Health and Safety Executive (HSE), Offshore Hydrocarbon Releases Statistic - 2012

iii SINTEF, Blowout and Well Release Characteristics and Frequencies, 2013, SINTEF F25705, 19-12-2013

iv Lloyd's Register Consulting, Blowout and well release frequencies based on SINTEF offshore blowout database 2013, Report no. 19101001-8/2014/R3,Final, 22-05-2014

v Mott MacDonald Ltd for HSE, UKOOA, IP: PARLOC 2001; *The update of Loss of Containment Data for Offshore Pipeline*s, July 2003, 5th Edition

vi DNV Report no. 2009/1115: Energy Report - Recommended Failure Rates for Pipelines. Rev 01, 2010-11-16

vii OTC, "A Historical Review on Integrity Issues of Permanent Mooring Systems", Doc. No. OTC 24025, 2013.