Case Study 1: Ultra-Deepwater Drilling

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

Submitted by
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ABBREVIATION	EXPLANATION
BSEE	Bureau of Safety, and Environmental Enforcement
BOP	Blowout Preventer
DMAS	Dead-man/Auto-shear System
DP	Dynamic Positioning
ESD	Emergency Shutdown
FMECA	Failure Mode and Effect and Criticality Analysis
HAZID	Hazard Identification Study
HPHT	High Pressure High Temperature
HPU	Hydraulic Power Unit
LMRP	Lower Marine Riser Package
LOEP	Loss of Electric Power
LOHP	Loss of Hydraulic Power
MAH	Major Accident Hazard
MODU	Mobile Offshore Drilling Unit
MT	Metric Ton
MUX	Multiplex Control System
POCV	Pilot Operated Check Valve
psi	Pounds Per Square Inch
ROV	Remotely Operative Vehicle
SPM	Sub Plate Mounted Valves

1. Introduction

1.1 Background

As part of the Bureau of Safety and Environmental Enforcement (BSEE) Emergent Technologies project, a risk assessment framework was developed to qualify new technology applications submitted to BSEE. To provide a better understanding of the risk assessment framework, ABSG Consulting Inc. 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-deepwater drilling
- Scenario 2: Floating production installation with a surface blowout preventer (BOP)
- Scenario 3: Managed Pressure Drilling
- Scenario 4: Production in High Pressure High Temperature (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 assessment do not reflect actual real-life projects and the studies performed for real-life project will be more comprehensive than what is provided in this document.

This document provides information on the Scenario 1: Ultra-deepwater drilling.

2. Scenario Development

2.1 Scenario Descriptions

The objective of the scenario is to identify and rank the risks associated with a drilling operation in ultra-deep water Gulf of Mexico (GoM), in order to determine if the risks are comparable to a conventional (i.e., not ultra-deep water) drilling scenario.

Performing drilling operations in an ultra-deep water environment will introduce new challenges based on the site and the associated environment. The external pressure on equipment on the seafloor and the loads on the drilling riser and associated equipment will greatly increase, while the materials of construction will need to handle extreme conditions. In the case of a blow out in ultra-deep water, industry consensus is that these wells are generally harder to contain as the pressure at the seafloor restricts flow from the well and prolongs the time required for the well to "bridge over". In general, deep water complicates well control, thereby requiring that the well control system contain additional redundancies. Deepwater wells under the jurisdiction of BSEE will have subsea BOPs, as compared to shallower water wells that may have a surface BOP. The drilling unit used for an ultra-deepwater operation will need to be of the dynamically positioned type, as mooring a drilling unit in very deep water is not practical. Dynamic Positioning (DP) technology is not new technology as these units have been used for many years. Accordingly, drilling from DP units is also common.

To evaluate the scenario using the new technology risk assessment framework a Mobile Offshore Drilling Unit (MODU) with conventional drilling equipment is considered. The unit is equipped with DP2+ station keeping and designed to operate in the Gulf of Mexico environments. With its DP system, the unit can operate in up to 3,000-meter water depths and can drill up to 30,000 ft. with a Variable Drilling Load of up to 5,000 MT. The table below contains further details of the scenario characteristics.

For this scenario, the considered characteristics include the following:

Field Location	100 Miles offshore in the deep water Gulf of Mexico
Water Depth:	Approximately 6,000 ft.
Facility type	MODU Semi-submersible DP-2
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	subsea BOP
No. of development wells	15
Design Life	20 years

Rules and Regulation:
Design and build using recognized classification rules
IMO MODU code
SOLAS
and Applicable rules and regulation, where applicable

It is imperative to note that not all the design basis information is included here but it is expected that actual new technology application should include following supportive documentation, as applicable.

Engineering/Design Documents

- Design basis document providing 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

2.1.1 Purpose of the New Technology or Application

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 deep-water environments have pushed design criteria, normally used in onshore and shallow water wells, to values beyond their traditional limits.

Drilling in deep water generally means that the drilling unit will need to be a dynamically positioned unit. Dynamically positioned units maintain their position with an active propulsion system linked to one or more global positioning systems. Unlike a moored drilling unit, a DP unit can have some large excursions from position due to failures of equipment or Operator error. For this reason, these systems possess a high level of redundancy, categorized into three levels with each level having a more redundancy.

All drilling phases of deepwater and ultra-deepwater wells face challenges. The initial phases, generally composed of soft soil or mud, require a lot of experience in terms of jetting the conductor pipe to avoid sinking of the wellhead.

In the intermediate phases, engineers must be very careful to avoid loss of circulation due to the narrow window between pore pressure and low fracture pressure gradients. Well bore instability, always an issue for directional drilling, often limits the length of the deepwater well departures to values considered quite small in comparison to those obtained in shallow waters or onshore. In addition, the drilling of permeable rocks, many times just loose and unconsolidated sands, increases the chance of differential sticking. To complete the picture, watching closely well operation and drilling parameters to keep risks under control generally is not enough.[1]

2.1.1.1 Comparison of New Technology versus Existing Solutions

The main challenges of ultra-deepwater production relate to the extreme environment of operating and drilling into rock, sand, and shale at 6,000 to 10,000 feet below sea level. The function of the well control equipment, regardless of the operating depth, will remain the same. Equipment must be able to withstand pressure equal to thousands of pounds per square inch (psi) and temperatures just above freezing. These extreme conditions require the use of specially designed systems and equipment, which can survive these conditions with little or no intervention during their design life. The main function of well control equipment is to cope with extreme erratic pressures and uncontrolled flow (formation kick) emanating from a well reservoir during drilling. An uncontrolled kick can potentially lead to a catastrophic blowout event. This scenario will review the use of a conventional subsea BOP for well control during ultra-deepwater drilling operations and any additional hazards/considerations that need to be accounted.

Innovative advancements in technology have allowed more ultra-deep water fields to be developed. For example, advances in seismic imaging have addressed visibility issues, allowing Operators to see fields 10,000 feet underwater.[1]

2.2 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 significant new technologies and techniques. Subsea BOPs and their control systems have evolved to support greater drilling depths and harsher environments. As drilling depths have increased so has the size and weight of the subsea BOP stacks. Maintenance and serviceability of the BOP stacks have also become more sophisticated with the increased design complexity and challenging end user demands. Relatively recent enhancements in Remotely Operated Vehicle (ROV) technology and increased inherent reliability in the BOP components have made drilling at ultra-deep water depths a possibility. Taking all the above aspects into consideration, the proposal of a subsea BOP in ultra-deepwater drilling is deemed a suitable candidate for the new technology evaluation process.

The workflow to be followed within the new technology risk assessment framework depends on the novelty of the combination of the technology and the applied conditions. Figure 1 contains an overview of the emergent Technology Assessment workflow. This subsea BOP scenario applies Workflow 2, which is for known technology (subsea BOP) in a different or unknown condition (ultra-deepwater drilling). The risk assessment will focus on the identification of Major Accident Hazards (MAHs) and associated

[1] Overcoming Deep and Ultra Deepwater Drilling Challenges, Luiz Alberto S. Rocha, P. Junqueira and J.L. Roque , OTC 2003

consequences. As part to the risk assessment, the team will identify the barrier critical systems that can prevent MAHs or provide mitigation against the consequence resulting from MAHs.

Operation in a different or unknown condition using the known technology/barrier critical system would require a greater focus on the consequence effects from the identified MAHs. In addition, failure of the barrier critical system due to potential incompatibility or inadequate design for the unknown condition could lead to the realization of a major accidents hazard (MAH). A barrier analysis to identify the critical success attributes for the barrier elements that constitute the barrier critical system is of extreme significance.

The Hazard Identification Study (HAZID) carried out as part of the risk assessment should identify the MAHs and affected barrier functions. Section 3 of this report covers the risk assessment for this scenario and related findings. Section 4 of this report provides the barrier analysis, which involves the review of select barrier critical system (subsea BOP) to understand what equipment need to succeed in order for the barrier system to perform its barrier function(s). For this purpose, a barrier model is developed and analyzed to determine the ways in which the barrier critical system can succeed 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 critical system.

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. This is followed by identifying the required barrier critical system function(s) for each barrier critical system and the relevant barrier elements. For each barrier element, physical and operational tasks are identified that enable the barrier critical system function. Performance influencing factors and attributes along with the relevant success criteria can be defined for the barrier element to perform its intended physical/operational tasks, thereby realizing the barrier function.

Note: For further detail on risk assessments, refer to the “Risk Assessment for New Technologies Technical Note”. For more information on barrier analysis, refer to the “Barrier Analysis for New Technologies Technical Note”.

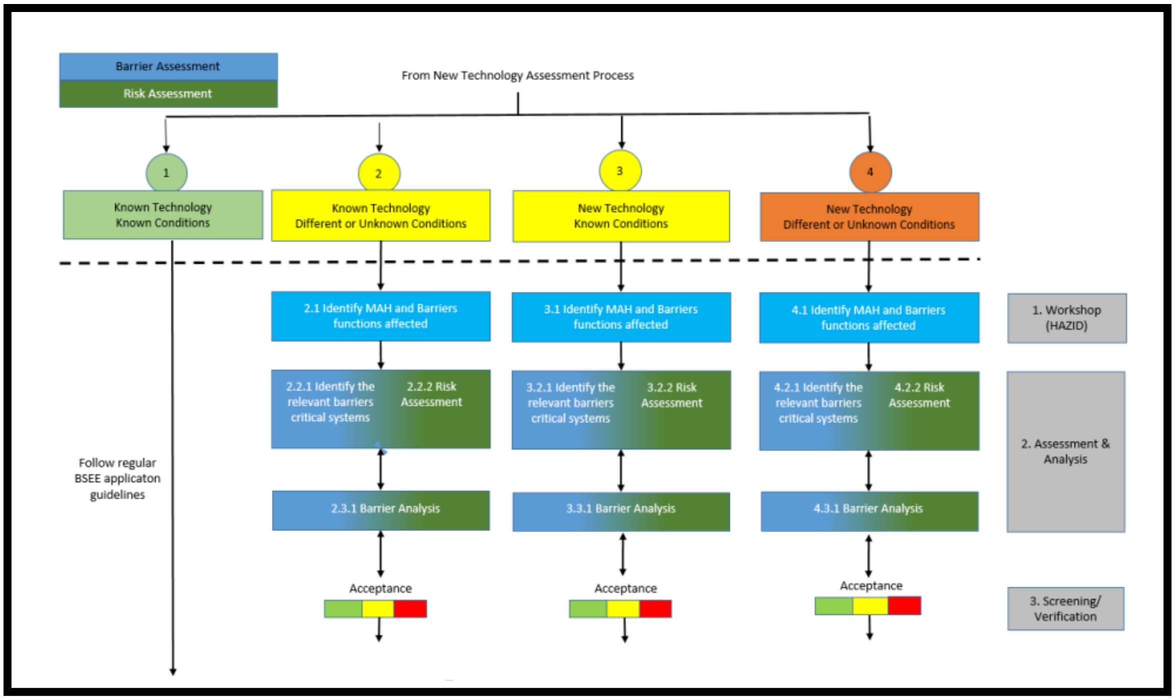

Figure 1. New Technology Assessment Framework

Operation in unknown conditions using known technologies/barriers can have an effect on the consequence from the identified MAHs or contribute to the failure of an existing barrier for a MAHs due to its incompatibility with the unknown conditions.

3. Scenario Risk Assessment

3.1 HAZID

3.1.1 Method Overview

The HAZID technique is a brainstorming activity to consider hazards of system. It is prompted by guidewords to assist with hazard recognition. The guideword list contains a mixture of hazard sources and factors that may feature in the control of and recovery from those hazards. The basic HAZID Study approach involved:

- The assembly of an appropriate team of experienced personnel, including representatives of all disciplines involved in the area being reviewed and (as needed) interfaces with adjacent systems.
- Short presentations detailing the scope of the study.
- Application of the relevant guidewords to identify hazards and other HSE concerns.
- Recording the discussions on worksheets summarizing the nature of the hazard, its consequences, threats, the safeguards in place, risk ranking, and recommendations for any actions required.

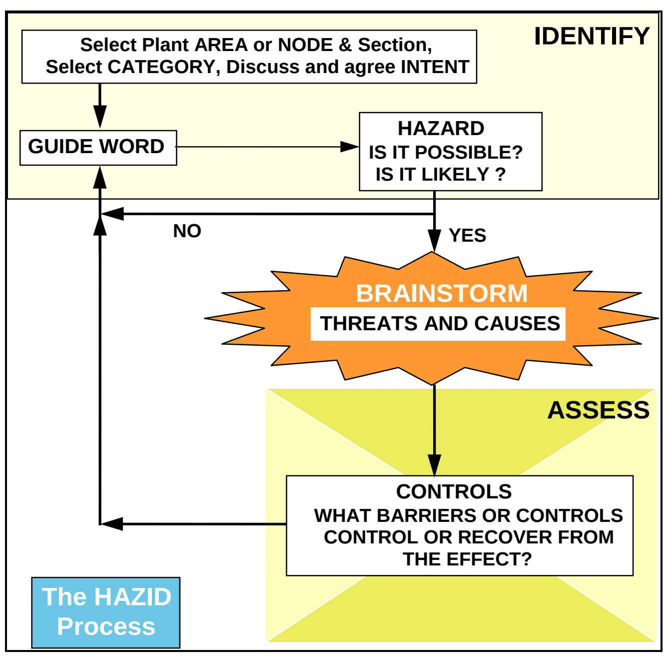

Figure 2. The HAZID Study Process

Following the above process, the HAZID Study output was recorded on worksheets made up of the following fields:

Hazard Scenario	A situation or sequence of events that have the potential to lead to a postulated failure (hazardous situation or accident).
Cause	Possible causes that could lead to the hazard scenario occurring.
Potential Effects	The consequence of the hazard scenario occurring.
Safeguards	The measures in place to prevent or mitigate the hazard scenario occurring (alarms, trips, standards, regulations etc.).
Risk Ranking	An overall risk ranking of the severity of the consequence and the likelihood of the hazard scenario occurring (before implementing any recommendations).
Recommendations	Actions to reduce the likelihood of the initiating event provide an additional barrier to break the accident sequence, or mitigate the predicted consequences.
Responsibility	Individual/company who has responsibility to provide response to recommendation.

3.1.2 Risk Ranking

It is typical to undertake a qualitative risk ranking during the HAZID Study as this greatly assists the team in knowing when to make a Recommendation (Action Item) and then helping in prioritizing actions later.

The risk related to each potential event is the product of the severity of the potential consequence multiplied by the estimated frequency/likelihood of the event occurring. All potential effects received a risk ranking using the Risk Matrix presented below.

Category		Consequence Severity				
Asset		No shutdown, costs less than $10,000 to repair	No shutdown, costs less than $100,000 to repair	Operations shutdown, loss of day rate for 1-7 days and/or repair costs of up to $1,000,000	Operations shutdown, loss of day rate for 7-28 days and/or repair costs of up to $10,000,000	Operations shutdown, loss of day rate for more than 28 days and/or repair more than $100,000,000
Environmental Effects		No lasting effect. Low level impacts on biological or physical environment. Limited damage to minimal area of low significance.	Minor effects on biological or physical environment. Minor short-term damage to small area of limited significance.	Moderate effects on biological or physical environment but not affecting ecosystem function. Moderate short-medium term widespread impacts e.g. oil spill causing impacts on shoreline.	Serious environmental effects with some impairment of ecosystem function e.g. displacement of species. Relatively widespread medium-long term impacts.	Very serious effects with impairment of ecosystem function. Long term widespread effects on significant environment e.g. unique habitat, national park.
Community/ Government/ Media/ Reputation		Public concern restricted to local complaints. Ongoing scrutiny/ attention from regulator.	Minor, adverse local public or media attention and complaints. Significant hardship from regulator. Reputation is adversely affected with a small number of site focused people.	Attention from media and/or heightened concern by local community. Criticism by NGO's. Significant difficulties in gaining approvals. Environmental credentials moderately affected.	Significant adverse national media/public/ NGO attention. May lose license to operate or not gain approval. Environment/ management credentials are significantly tarnished.	Serious public or media outcry (international coverage). Damaging NGO campaign. License to operate threatened. Reputation severely tarnished. Share price may be affected.
Injury and Disease		Low level short-term subjective inconvenience or symptoms. No measurable physical effects. No medical treatment required.	Objective but reversible disability/impairment and/or medical treatment, injuries requiring hospitalization.	Moderate irreversible disability or impairment (<30%) to one or more persons.	Single fatality and/or severe irreversible disability or impairment (>30%) to one or more persons.	Short or long term health effects leading to multiple fatalities, or significant irreversible health effects to >50 persons.
		Low (1)	Minor (2)	Moderate (3)	Major (4)	Critical (5)
Likelihood	Almost Certain (E) Occurs 1 or more times a year	High	High	Extreme	Extreme	Extreme
	Likely (D) Occurs once every 1-10 years	Moderate	High	High	Extreme	Extreme
	Possible (C) Occurs once every 10-100 years	Low	Moderate	High	Extreme	Extreme
	Unlikely (B) Occurs once every 100-1000 years	Low	Low	Moderate	High	Extreme
	Rare (A) Occurs once every 1000-10000 years	Low	Low	Moderate	High	High

Figure 3. Risk Matrix

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

1. Do the changed/unknown conditions directly impair, 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/unknown conditions give potential for increased or new consequences related to the MAH in question?

3.1.3 Scope

The scope of this assessment is the drilling activities and associated operations that may result in harm to people or damage to the environment. Operations concerns that result only in downtime lost production are not within the scope of this study. The HAZID technique is a brainstorming activity to consider hazards of system.

Table 1 lists the hazards that would be applicable to the systems under consideration.

Table 1. HAZID Scenarios

Hazard Category	Hazardous Scenarios
Hydrocarbons in Formation during Deepwater Drilling	• Well Kick • Improper Well Design • Sour Gas Corrosion • Loss of Integrity for Cement or Casing
Environmental Conditions	• Exceeding Environmental Conditions (considered for technology application)
Drilling Operation	• Failure to Detect Kick • Failure to Control A Kick • Loss of Mud Circulation
Simultaneous Operation	• BOP Operation • Collision

3.1.4 Assumptions

The assumptions made at start of the workshop for HAZID study include the following:

- Drilling system is designed in accordance with recognized standards
- Equipment is delivered and ready to use
- Contractor is aware of Safe Work Practices
- Approved operating procedures will be in place before the start of operation

3.1.5 Results and Conclusions

The result of the HAZID led to the development of 14 recommendations for scenarios where the resulting risk was moderate or high. The intent of the recommendation is to mitigate the risk to an acceptable level. Accordingly, the drilling company should implement these recommendations in order to ensure that the operation has an acceptable level of risk. Table 2 below contains the recommendations. Section 3.1.9 contains the HAZID Study worksheets.

Table 2: HAZID Recommendations

Recommendations (HAZID)
1. Ensure drilling unit is suitable for environment condition experienced in ultra-deepwater.
2. Ensure the drilling unit can maintain the station under adverse weather condition during well control events.
3. Perform DP system FMEA.
4. Perform visual inspection before drilling operations.
5. Perform Failure Mode and Effect and Criticality Analysis (FMECA) for well control systems.
6. Ensure software tools used for well design are properly validated.
7. Ensure well design process considers "Cold Eyes Review" of well design.
8. Ensure adequate hydraulic simulations and zonal flow control including fracture design, multi-zone, and flow analysis and reservoir simulation.
9. Ensure the use of NACE MR-0175 materials when the presence of H_2S is known.
10. Develop a H_2S mitigation strategy in accordance with 30 CFR-250 if H_2S is detected in the well or well stream.
11. Perform adequate stress analysis and finite element analysis for cementing with respect to deep-water operations.
12. Ensure competency and training of all Operators involved with drilling operations is sufficient for ultra-deepwater drilling operations.
13. Ensure that mud pit monitoring considers the effect of mud volume due to ultra-deep water distances between well and the drilling facility.
14. Ensure analysis is done to determine level of redundancy in the well control system and ensure that single points of failure in the well control system are eliminated.

The overall finding in the HAZID is that while the drilling equipment used may be similar to that used in other more conventional operations, the environment in ultra-deepwater drilling will have a significant impact on the risks associated with the operations. The use of dynamically positioned drilling units is generally thought to reduce risk. However, there are unique hazards associated with DP units. These hazards primarily involve excursions from the intended position that can result in collisions, damage to equipment and releases of hydrocarbons. For this reason, the DP rating of the unit should be carefully considered, as this will have a direct impact on the risk associated with the drilling operation.

3.1.6 MAH Identification

This HAZID aims to identify any impact on MAHs from new technology and/or changed conditions. 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. For this scenario, MAH is defined as any incident or event that can lead to safety or environmental consequence of four or higher without considering any safeguards in place as indicated in the risk matrix shown in Figure 3 Risk Matrix. During this HAZID, the identified MAH was a Blowout resulting in release above mud line/water column during drilling operation in the ultra-deep water conditions. There were no new MAHs identified that were unique to ultra-deep water conditions.

However, the HAZID team concludes the exposure of the equipment to the ultra-deep water condition can affect the critical barriers.

3.1.7 Barrier Critical System Identification

Based on the review of the HAZID, the following table lists the identified critical barriers that can either prevent the MAHs from occurring or mitigate the consequence of the MAH.

Barrier Critical System	Description

Well Control System	Systems and equipment whose failure can lead to a loss of well control during the drilling operation and resulting in potential blowout. This includes the following:
	• Well Control system:
	  ○ BOP
	  ○ Choke and Kill Line
	  ○ Choke and Kill Manifold
	  ○ Riser Gas System
	  ○ Lower Marine Riser Package (LMRP)
	  ○ Drill String/Casing Safety Valves
	  ○ Mud Gas Handling System
	• Diverter System

Well/Pressure Containment System	System components that support the mitigated measure during loss of well control. This includes: • Casing • Cementing • Well Head • Riser • Capping Stack • Relief Well

Barrier Critical System	Description

Emergency Shutdown (ESD) and Associated System/Protective	All ESD measures that could minimize the risk by isolating hydrocarbon inventories to minimize release durations and escalation potential. Which includes
	• Protective systems:
	  ○ Blast Walls
	  ○ Explosion proof equipment
	  ○ Sprinklers
	  ○ Deluge
	  ○ Fire Suppression System
	  ○ Emergency Shutdown
	  ○ Fire and Gas Detection System
	  ○ Dampers and Ventilation Control

The table below provides function information for each of the identified barrier critical system

Physical Barrier	Function
Well/Pressure Containment Systems	
Casing	Designed to contain the escape of oil or gas in case of any emergency
Cement	
Well Head	A wellhead is the piece at the surface of an oil or gas well providing structural and pressure-containing interface for drilling and production equipment. The primary purpose of a wellhead is to provide the suspension point and pressure seals for the casing strings that run from the bottom of the hole sections to the surface pressure control equipment.
Riser	Provide interface between subsea and the topside by connecting subsea BOP to the drilling facility. Also provides supports to Choke and kill lines
Well Control System	
BOP	Provides means to shut in the well during well control scenarios
Redundant BOP Control System	A blowout preventer is a large, specialized valve or similar mechanical device, usually installed redundantly in stacks, used to seal, control and monitor oil and gas wells. Developed to cope with extreme erratic pressures and uncontrolled flow (formation kick) emanating from a well reservoir during drilling. In addition to controlling the downhole (occurring in the drilled hole) pressure and the flow of oil and gas, blowout preventers are intended to prevent tubing (e.g., drill pipe and well casing), tools and drilling fluid from being blown out of the wellbore (also known as bore hole, the hole leading to the reservoir) when a blowout threatens. Blowout preventers are critical to the safety of crew, rig (the equipment system used to drill a wellbore) and environment, and to the monitoring and maintenance of well integrity. Blowout preventers provide fail-safety to the systems that include them.

Well Control System	Mainly to maintain the fluid column hydrostatic pressure and formation pressure to prevent influx of formation fluids into the wellbore. This technique involves the estimation of formation fluid pressures, the strength of the subsurface formations and the use of casing and mud density to offset those pressures in a predictable fashion.
Diverter System	The diverter, an annular preventer with a large piping system underneath, diverts the kick from the rig. It is not used when drilling riserless.
Emergency Shutdown (ESD) and associated System/ Protective Systems	
Blast Walls	Barrier designed to protect vulnerable buildings or other structures and the people inside them from the effects of a nearby explosion
Explosion proof equipment	Mainly to protect electrical equipment to prevent an explosion when used in a flammable gas atmosphere, in the presence of combustible dust or easily ignited fibers.
Sprinklers	Types of Sprinklers: • Wet Pipe Systems • Dry Pipe Systems • Deluge Systems • Pre-action Systems • Foam Water Sprinkler Systems • Water Spray • Water Mist Systems
Deluge	Used for special hazards where rapid fire spread is a concern. System provides a simultaneous application of water over the entire hazard. They are also installed in personnel egress paths or building openings to slow the escalation of fire. Operation - Activation of a fire alarm initiating device, or a manual pull station, signals the fire alarm panel, which in turn signals the deluge valve to open, allowing water to enter the piping system. Water flows from all sprinklers simultaneously.
Fire Suppression System	Commonly used on heavy power equipment using a combination of dry chemicals and/or wet agents to suppress equipment fires in helping to control damage and loss to equipment. Automatic fire suppression systems control and extinguish fires without human intervention. Examples of automatic systems include: • Fire Sprinkler System • Gaseous Fire Suppression • Condensed Aerosol Fire Suppression
Emergency Shutdown	Designed to minimize the consequences of emergency situations which may otherwise be hazardous.

Fire and Gas detection system	The gas detection system monitors continuously for the presence of flammable or toxic gases, to alert personnel and allow the manual or automatic initiation of control actions in order to minimize the probability of personnel exposure, explosion and fire. Flammable gas detection system is used to measure the concentration of flammable gas across a defined range. Upon detection of sufficient quantities of flammable gas to alarm and initiate executive actions as detailed in the Fire and Gas Cause and Effects. The fire detection system monitors continuously for the presence of a fire to alert personnel and allow the manual or automatic initiation of control actions in order to minimize the likelihood of fire escalation and probability of personnel exposure. It detects all fires and upon detection generates the appropriate indications and panel alarms and to initiate executive actions as detailed in the Fire and Gas Cause and Effects.
Dampers and Ventilation Control	Designed to ensure smoke damage is kept to a minimum. Fire dampers are used as fire control strategy.
Dynamic Positioning (DP) System	Aid in maintaining of the station keeping for the drilling facility

The Barrier model will be developed as per the guidelines provided in the barrier model template guide for all identified critical barriers. (Ref)

As a representation of the barrier model template, a barrier model for the BOP system is developed for this project and is provided in Section 4.

3.1.8 Additional Risk Assessment Work

During the initial Hazard identification study, the conclusion was reached that drilling operation in the ultra-deep water environment does not produce additional consequence versus what is experienced during the drilling operation in the conventional deepwater production operations.

There were multiple scenarios where consequence related to blowout were identified but it is imperative to note here that drilling operation in the ultra-deep water environment will not lead to any additional risk to the facility or the environment beyond what will be experienced in the normal conditions.

The following table provides information on the various studies that can be performed as part of the general engineering practice and in most cases recommended by Operators. Table 3 also provides the information on whether or not the deep water environment can affect the study outcomes.

Table 3: Additional Studies

Study	Comment
Failure Mode and Effect and Criticality Analysis for the Critical Systems	Provide information on the failure modes of critical system.
System Reliability Assessment	Provide information on the system reliability while operation
Escape Evacuation and Rescue Analysis (EERA)	Provide information on impairment of escape routes and evacuation means. Focus on exposure of escape routes and evacuation means to fire loads. The EERA Study will be not be dependent on or influenced by the operation in the ultra-deepwater environment.
Dropped Objects Study	Assess exposure of the subsea system to dropped object. The Study will be not be dependent on or influenced by the operation in the ultra-deepwater environment.
Collision Risk Assessment	Will provide information on potential collision risk, but the study will be not be dependent on or influenced by the operation in the ultra-deepwater environment.
Helicopter Risk Assessment	Will only provide information on risk contribution to personnel, but the study will be not be dependent on or influenced by the operation in the ultra-deepwater environment.
Environmental Risk Analysis (ERA)	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	Exposure of physical barriers to explosion loads, and subsequent exposure from fires but the study will be not be dependent on or influenced by the operation in the HPHT environment. Operation in the ultra-deepwater environment will not affect the study outcome.

3.1.9 HAZID Worksheet

Table 4. HAZID Worksheets – Node 1. Deepwater Drilling

Node: 1. Deepwater Drilling

Hazard	Hazardous Scenario	Cause	Consequence	Effective Safeguards	Consequence Categories	Before Risk Reduction			Recommendations
						S	L	RR	
Hydrocarbons in formation during ultra-deepwater drilling	Well Kick	1. • Formation pressure exceeds expectation • Loss of Circulation • Riser Gas Expansion • Premature detonation of explosive charge • Casing/Riser Wear corrosion and fatigue during operations • BOP Control system/mechanical failure • Well Control Equipment wear, corrosion and fatigue during operations • Shallow Gas	1. Blowout resulting in Fire and Explosion at the Facility	1. Maintain Hydrostatic overbalance	Safety	5	B	Extreme	1. Ensure drilling unit is suitable for environment condition experienced in ultra-deep water.
			2. Blowout resulting in Underground Release up to and including broaching	2. Fluid parameters monitoring	Environmental	3	B	Moderate	2. Ensure the drilling unit can maintain the station under adverse weather condition during well control events.
			3. Blowout resulting in release above mud line/water column	3. Real Time monitoring of pore pressure 4. Loss of circulation contingency plan 5. Riser gas expansion contingency plan 6. Emergency Disconnect 7. Surface parameters monitoring (Flow rate and Pit Volume) 8. Pressure Containment system: • Casing/liner • Cement • Well head • Riser 9. Redundancies in BOP Control system 10. Well Control system: • BOP • Choke and kill Line	Environmental	5	B	Extreme	4. Perform visual inspection before drilling operations. 5. Perform FMECA for Well control systems.

Node: 1. Deepwater Drilling

Hazard	Hazardous Scenario	Cause	Consequence	Effective Safeguards	Consequence Categories	Before Risk Reduction			Recommendations
						S	L	RR	
				• Choke and Kill Manifold • Riser Gas System • LMRP • Drill String/Casing Safety Valves • Mud Gas Handling System • BOP Control System 11. Diverter system 12. Emergency Response Plan 13. Protective systems: • Blast Walls • Explosion proof Equipment • Sprinklers • Deluge • Fire Suppression system • Emergency Shutdown • Fire and Gas detection system • Dampers and Ventilation Control • Interface to production protection systems 14.Relief well drilling 15. Dynamic kill 16. ROV intervention 17. Capping stack					
Environmental conditions on the surface	Environ-mental condition exceeds rig capa-bilities during drilling operation	1. • Insufficient reserve buoyancy for drilling operation • DP thrust inadequate to maintain station • Not enough drill pipe to reach required drilling depth • Insufficient air gap	1. Loss of station keeping within allowable limits - minor excursion - operational issue (no HSE consequences)	1. Well Control system: • BOP • BOP Control System • Choke and kill Line • Choke and Kill Manifold • Riser Gas System • LMRP • Drill String/Casing Safety Valves • Mud Gas Handling System					1. Ensure drilling unit is suitable for environment condition experienced in ultra-deep water.
			2. Loss of station keeping outside allowable	2. Emergency Disconnect using LMRP	Safety	4	B	High	2. Ensure the drilling unit can maintain the station under adverse weather

Node: 1. Deepwater Drilling

Hazard	Hazardous Scenario	Cause	Consequence	Effective Safeguards	Consequence Categories	Before Risk Reduction			Recommendations
						S	L	RR	
			limits - major excursion and potential for damage due to collision with other vessel or production facility						condition during well control events.
			3. LMRP disconnects from wellhead. Potential damage to subsea structure from dragged drilling riser and potential for environmental release	3. DP System Test when entering exclusion zone	Environmental	3	B	Moderate	3. Perform DP system FMEA.
			4. Inability to land the BOP - operational issue (no HSE consequences)	4. Emergency Response Plan 5. Drilling unit verification program 6. Protective systems: • Blast Walls • Explosion proof equipment • Sprinklers • Deluge • Fire Suppression system • Emergency Shutdown • Fire and Gas detection system • Dampers and Ventilation Control • Interface to production protection systems					
Hydrocarbons in formation during	Improper Well design	1. • Inaccurate soil and	1. Poor quality cementing leading to	1. Review and analysis of Geological data	Environmental	3	C	High	6. Ensure software tools used for well design are

Node: 1. Deepwater Drilling

Hazard	Hazardous Scenario	Cause	Consequence	Effective Safeguards	Consequence Categories	Before Risk Reduction			Recommendations
						S	L	RR	
Ultra-deep-water drilling		geological data • Human Error • Inaccurate modeling methods	potential for loss of containment from the well						properly validated.
			2. Casing failure leading to loss of containment for the well	2. Pre-spud meeting	Environmental	3	C	High	7. Ensure well design process considers "Cold Eyes Review" of well design.
			3. Failure of down hole equipment such as packers leading to inability to control well between zones, potentially leading to Well blowout	3. Correlation wells review 4. Lessons learned from adjacent wells and fields 5. Management of change review 6. Independent / governmental review and approval of well design	Safety	5	A	High	8. Ensure adequate hydraulic simulations and zonal flow control including fracture design, multi-zone, flow analysis, and reservoir simulation.
	Sour Gas Corrosion	1. • Use of improper materials • Failure to identify H2S in the well stream • Excessive water injection • Packer or down hole equipment leakage	1. Well control equipment wear, corrosion and fatigue during operations leading to loss of containment	1. Drilling equipment rated for sour service	Environmental	3	B	Moderate	9. Ensure the use of NACE MR-0175 materials when the presence of H2S is known.
			2. Blowout resulting in Fire and Explosion at the Facility	2. Sour gas corrosion inhibitors in the mud 3. BOP System rated for sour service 4. Choke and kill system equipment rated for sour service	Safety	5	A	High	10. Develop a H2S mitigation strategy in accordance with 30 CFR-250 if H2S is detected in the

Node: 1. Deepwater Drilling

Hazard	Hazardous Scenario	Cause	Consequence	Effective Safeguards	Consequence Categories	Before Risk Reduction			Recommendations
						S	L	RR	
				5. Verification of well information design (operations engineer, senior well engineer)					well or well stream.
	Loss of integrity of cement or casing	1. • Shallow Gas • Formation damage during drilling • Improper centralization of casing • Incomplete cement placement or inadequate cement formation / cement casing bond • Cement contamination via mud • Shrinkage • Mechanical stress and strain due to ultra-deep water conditions • Geochemical attack • Loss of riser margin	1. Casing/Riser wear corrosion and fatigue during operations - operational issue resulting in suspension of drilling in order to repair and replace compromised equipment	1. Cement integrity testing					11. Perform adequate stress analysis and finite element analysis for cementing with respect to deep water operations.
			2. Blowout resulting in Fire and Explosion at the Facility	2. Casing integrity testing 3. Verification (pressure testing) of the integrity testing 4. Verification of torque turn 5. Cementing procedures 6. Cement analysis 7. Wireline logging 8. BOP system 9. Well control procedures 10. Verification of well information design (operations engineer, senior well engineer)	Safety	5	B	Extreme	
Drilling Operations	Failure to detect a kick	1. • Inaccurate down hole instrumentation • Inadequate mud weight monitoring • Inexperienced	1. Blowout resulting in Fire and Explosion at the Facility	1. Mud weight monitoring	Safety	5	A	High	12. Ensure competency and training of all Operators involved with drilling operations is sufficient for ultra-deepwater

Node: 1. Deepwater Drilling

Hazard	Hazardous Scenario	Cause	Consequence	Effective Safeguards	Consequence Categories	Before Risk Reduction			Recommendations
						S	L	RR	
		personnel involved in drilling operations		 2. Adherence to well control procedures 3. Mud pits level monitoring (trip tank) 4. Gas cut mud monitoring 5. Kick detection system (flow show) 6. Mud pump pressure and stroke monitoring 7. Mudlogging System 8. Pit volume totalizer (PVT) 9. Third party kick detection system					drilling operations. 13. Ensure that mud pit monitoring considers the effect of mud volume due to ultra-deep water distances between well and the drilling facility.
	Failure to control a kick	1. • Failure in well control system • Inaccurate down hole instrumentation • Inexperienced personnel involved in drilling operations • Loss of mud circulation • Insufficient mud hydrostatic pressure	1. Blowout resulting in Fire and Explosion at the Facility	1. Poor boy degasser and vacuum degasser 2. Maintaining sufficient mud weight 3. Tertiary well control with barite / cement 4. BOP System 5. Choke and kill system 6. Independent verification of system by classification society 7. Well Control surface equipment	Safety	5	A	High	12. Ensure competency and training of all Operators involved with drilling operations is sufficient for ultra-deepwater drilling operations. 14. Ensure analysis is done to determine level of redundancy in the well control system and ensure that single points of failure in the well control system are eliminated.
	Loss of mud circulation	1. Mud system / pump failure	1. Blowout resulting in release above mud	1. Flow and pressure monitoring	Environmental	3	B	Moderate	

Node: 1. Deepwater Drilling

Hazard	Hazardous Scenario	Cause	Consequence	Effective Safeguards	Consequence Categories	Before Risk Reduction S	Before Risk Reduction L	Before Risk Reduction RR	Recommendations
			line/water column						
			2. Blowout resulting in Fire and Explosion at the Facility	2. Direct seawater feed to the mud system 3. Lost circulation material on board (mica flake etc.) 4. Maintaining industry accepted drilling practices 5. BOP System 6. Choke and kill system 7. Mud pits level monitoring (trip tank) 8. Tertiary well control with barite / cement 9. Well control procedures	Safety	5	A	High	
Simultaneous Operations	BOP contacts existing subsea equipment during installation	1. • Communication Error • Dropped Objects • DP system malfunctions • Lifting equipment malfunctions	1. Damage to subsea equipment potentially resulting in release of hydrocarbons to the sea	1. Job Safety Analysis (task level risk analysis)	Environmental	3	B	Moderate	
			2. Damage to the BOP resulting in a loss of functionality. Potential for loss of Well Control event	2. Simultaneous operations plan 3. Emergency Response Plan 4. Use of ROVs to visually monitor installation	Safety	3	A	Moderate	
	Collision between drilling unit and vessel in the exclusion zone	1. • DP system malfunctions • Vessel pilot error • Poor weather conditions • Navigational system errors	1. Potential damage to drilling unit	1. Radar on the vessels	Safety	2	A	Low	
			2. Potential damage to or sinking of a service vessel	2. Simultaneous operations plan 3. Communications plan 4. DP System Test when entering exclusion zone	Safety	5	A	High	

4. Barrier Function and Barrier Critical Systems

4.1 Barrier Function Description in Relation to Major Accident Hazard

The HAZID led to the identification of well blowout as a major Accident Hazard that can lead to undesirable safety and environmental consequences. The barrier function selected based on relevance for this scenario and input from the risk assessment is **"Shut in Well and Control Wellbore".** This barrier function relates to preventive control, meaning that it is to prevent a MAH from occurring. The main focus will be on controlling 'kicks' and providing a means of shutting in the wellbore, in order to prevent potential escalation to a blowout.

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 subsea BOP system is vital for circulating and controlling these kicks. The subsea BOP system is designed to shut in the well on demand and prevent hydrocarbons from blowing out of the well and into the riser, or open sea. When a well has been shut in, hydrocarbons are contained beneath the closed ram or annular BOP. To regain control of the wellbore and continue drilling activity, a well kill procedure is initiated.

4.2 Relevant Barrier Critical Systems and Brief Summary of Their Role in Realizing the Barrier Function

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

1. Casing and Cementing – The integrity of the casing and cementing is crucial to zonal isolation to prevent the creation of more than the existing flow path. It allows for deeper drilling when the wellbore pressure surpasses 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 for an attachment point to connect the subsea BOP to the well, mainly lock and seal the BOP Stack. Any leak points on the wellhead would cause a blowout even if a subsea BOP is in place.
3. Subsea BOP – It is an assembly of well control equipment, including preventers, spools, valves, and nipples connected to the top of the wellhead. It can be used to shut in the well and provide means for regaining control of the well.
4. Marine Drilling Riser System – It connects the subsea BOP to the drilling vessel and is a continuation of the wellbore from the seabed to the surface. Similar to the casing, the riser integrity is crucial to prevent the creation of more than the existing flow path. It should also be able to withstand the pressure during barrier function. Additionally, it provides support for choke and kill lines as well as auxiliary lines.

5. 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 it. In addition, the BOP design should also take into consideration the dimensions and strength of the different drill strings for use in the drilling program.
6. Mud Circulation System – As mentioned, the mud is considered as the primary well barrier by providing hydrostatic pressure to prevent formation fluids from entering into the well bore. The mud circulation system and related equipment help in establishing the hydrostatic pressure for primary well control. In this scenario, where a well kick has already occurred and the well is shut in by the subsea BOP, the purpose of the circulation system is to transport hydrocarbons out of the well/riser to depressurize the well. Heavy mud will then be pumped through the kill lines/drill string to kill the well.

5. Selected Barrier Critical System – Subsea BOP

5.1 System Description and Basis of Design

In order to realize the barrier function "Shut in Well and Control Wellbore" during a drilling operation, at a minimum, the Barrier Critical Systems (independently or collectively) must perform their intended functions. For the purpose of this example and to assess the subsea BOP as a Barrier Critical System, a configuration is chosen. For the development of the model, the subsea BOP system was divided into four sub-systems:

- BOP Stack;
- Main Control System;
- Secondary Control System; and
- Dead-man/Auto-shear (DMAS) System.

Presented below is a description of each of the sub-systems and their relevant barrier elements.

<u>BOP Stack</u>

The BOP stack consists of a number of ram and annular preventers that are hydraulically actuated to shut in and control the wellbore. The BOP stack connects to the riser and the top of wellhead via two separate hydraulic connecters (LMRP/BOP and Wellhead connectors). In addition, choke and kill lines from the BOP stack will connect the BOP stack with the choke and kill manifold, located topside. It is pertinent to note that the choke and kill manifold is excluded from the subsea BOP system as it is considered part of the Mud Circulation system. However, the BOP 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 Subsea BOP system. The configuration of the BOP stack elements can vary depending on factors such as company preference, intended functionality of the BOP system and operating depth. The BOP stack configuration assumed for the barrier model is based on a 'typical' subsea stack that could be expected for drilling operations in ultra-deep water. Figure 4 depicts an illustration of the BOP stack configuration assumed for the barrier model. The barrier elements considered critical for the Subsea BOP stack to perform its intended functions consist of the following:

- Annular Preventers (2)
    - There is an upper and lower annular preventer that can close and seal around the drill string
- Blind Shear Rams (2)
    - There is an upper and lower blind shear ram that can (a) shear and seal the drill string or (b) close on open hole to seal the wellbore
- Pipe Rams (3)
    - There is an upper, middle and lower pipe ram that can close and seal around the drill string
- BOP Stack Mounted Choke/Kill Line Valves

- Valves that can isolate flow to the choke and kill lines (2 per line) allowing to control the flow to the choke and kill manifold
- Wellhead Connector
    - For connection of the subsea BOP stack to the wellhead
- LMRP/BOP Connector
    - For connection of the lower BOP stack to LMRP

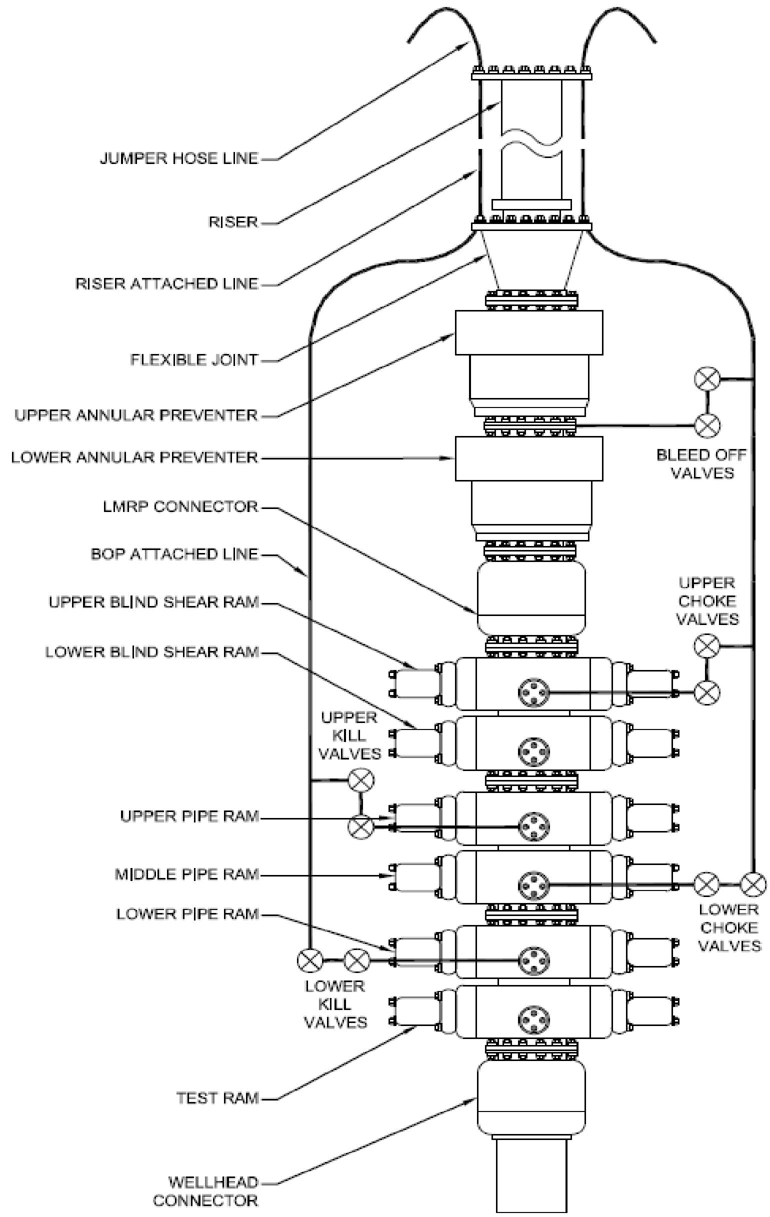

Figure 4. Typical Subsea BOP Stack Configuration

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Main Control System

The control systems used to actuate individual components of the BOP stack are considered part of the subsea BOP system. The purpose of the main control system is to provide an interface between the driller on the surface and the subsea BOP stack; and transfer the electric signals and hydraulic fluid for actuating stack components and reporting critical wellbore pressures. The main control system assumed for the barrier model is based on a typical Multiplex (MUX) control system. A MUX control system provides a shorter response time than a conventional hydraulic control system therefore is considered best practice for ultra-deep water applications. 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 BOP stack
- 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 subsea BOP 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 BOP stack 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
- Main Accumulator System
  - Consists of a series of surface and subsea accumulators used to provide hydraulic fluid to the Control Pods

Note that only elements of the MUX control system that have a direct impact on the BOP stack components fulfilling their intended function are considered. For instance, the Hydraulic Power Unit (HPU) and hydraulic supply are excluded, given that the BOP 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 main control system for the model are presented in Barrier Model Scope (Interfaces and Barrier Elements) and Key Assumptions.

Secondary Control System

The secondary control system 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, ROV operated control systems, and LMRP recovery systems. The 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 BOP system functions in place of the main control system for certain barrier critical 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, the ROV operated control system should not be considered a barrier element for that specific barrier critical function. The barrier elements considered critical for the ROV operated control system consist of the following:

- 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 BOP stack functions
- ROV Unit
  - Vehicle used to actuate BOP stack 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 Dedicated Emergency Subsea Accumulator System mounted on the BOP lower stack is assumed to be used for both ROV intervention (secondary control system) and auto-shearing purposes (DMAS control system). The assumptions and boundaries used to define the elements are presented in greater detail in Barrier Model Scope (Interfaces and Barrier Elements) and Key Assumptions.

Emergency Control System: Dead-man/Auto-shear (DMAS) System

Auto-shear and Dead-man systems are optional safety systems that are designed to shut automatically in the wellbore during unplanned emergency events. Auto-shear is a safety system designed to automatically shut in the wellbore in the event of an unintended disconnect of the LMRP, while the Dead-man 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. Deepwater/harsh environment applications typically employ DMAS systems, particularly where multiplex BOP controls and dynamic positioning of the vessel are used. A DMAS system is assumed for the subsea BOP barrier model, given that these conditions align with the scenario basis defined in Section 2.1

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 of shear rams 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 BOP stack 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 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 exist hydraulic lines 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 both the rigid conduit and the hotline manifold (the two means of supplying hydraulic power to the blue and yellow pods) lose supply, then the LOHP SPM is de-energized to its normally open position, thereby unblocking the power fluid flow until the third SPM valve.

When electric power is available, Subsea Electronics Module A and B within each blue and yellow pod continuously receive the power/command signals. 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 until the fourth SPM valve.

A final SPM valve (labeled 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 introduced, the hydraulic lines connected to the DMAS pod SPMs are disconnected, thereby leading to the auto-shear function.

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

- LOEP SPM Valve
  - 'Fail safe' SPM valve that actuates open upon loss of electric power
- LOHP SPM Valve
  - 'Fail safe' SPM valve that actuates open 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 rams.

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. Standards and procedures demand that the DMAS system is armed while the BOP 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 Barrier Model Scope (Interfaces and Barrier Elements) and Key Assumptions.

6. Barrier Model for Subsea BOP

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

6.1.1 Barrier Critical System Functions

The subsea BOP is a preventive barrier that provides means to shut in and control the well bore. The following Barrier Critical System Functions (BCSFs) identified as necessary for the subsea BOP system to perform the barrier function consist of the following:

- Close and Seal on Drill Pipe and Allow Circulation (BCSF1)
- Close and Seal on Open Hole and Allow Volumetric Well Control Operations (BCSF2)
- Circulate Across the BOP Stack to Remove Trapped Gas (BCSF3)
- Maintain LMRP-lower BOP Stack and BOP Stack-Wellhead Connection (BCSF4)
- Shear Drill Pipe or Tubing and Seal Wellbore - Command Closure (BCSF5)
- Shear Drill Pipe or Tubing and Seal Wellbore – Auto-Shear during Emergency Situation (BCSF6)
- Shear Drill Pipe or Tubing and Seal Wellbore - Emergency Disconnect Sequence (BCSF7)
- Hang-Off Drill Pipe (BCSF8)
- Strip Drill String (BCSF9)

These BCSFs stem from the requirements of API S53 and FMECA studies previously performed on the subsea BOP as part of another BSEE project. The sections below contain details regarding each of the BCSFs. Read the contents of this section in conjunction to the Barrier Model (presented in Barrier Model).

<u>Close and Seal on Drill Pipe and Allow Circulation (BCSF1)</u>

The Annular Preventer(s) or Pipe Ram(s) closes and seals the annular space between riser and drill string. The Annular Preventer(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, BOP Stack Mounted Choke and Kill Line Valves allow circulation of the well via the connected choke and kill lines. The main control system can activate the Annular Preventer(s), Pipe Ram(s) and the BOP Stack Mounted Choke and Kill Line Valves on demand. In the case of the Pipe Ram(s), activation by ROV intervention (secondary control system) is also possible if needed.

<u>Close and Seal on Open Hole and Allow Volumetric Well Control Operations (BCSF2)</u>

When no drill string is in the riser, Annular Preventer(s) or Blind Shear Ram closes and seals the open hole. The Annular Preventer(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, BOP Stack Mounted Choke and Kill Line Valves allow volumetric well control operations via the choke and kill lines. The main control system or secondary control system (if needed) may activate the Blind Shear Rams.

Circulate Across the BOP Stack to Remove Trapped Gas (BCSF3)

Closure of the BOP stack valves could result in an accumulation of gas under the closed BOP during displacement of the influx. The volume of the trapped gas depends on the volume between the Annular Preventer and choke line outlet. Prior to opening the BOP valves, the trapped gas needs to be removed by isolating the well using the lower rams, circulating kill weight mud through the choke and kill lines, displacing the choke line with water, or base oil, and venting the choke line to the Mud Gas Separator (MGS).

Maintain LMRP-lower BOP Stack and BOP Stack-Wellhead Connection (BCSF4)

On landing, the hydraulic connectors are latched and sealed to establish proper connection between (a) the riser/LMRP and lower BOP stack, and (b) the BOP stack and wellhead, respectively. Upon establishing proper connection, maintaining connection no longer requires hydraulic pressure. Connections must be maintained during the 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 – Commanded Closure (BCSF5)

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 (MUX control system) or secondary control system (ROV operated control).

Shear Drill Pipe or Tubing and Seal Wellbore – Auto-Shear during Emergency Situation (BCSF6)

The Blind Shear Ram close and shear the drill pipe or tubing and seal the wellbore. The ram lock is also engaged as part of the closing function. The activation of the Blind Shear Ram is by the DMAS control system that must be armed by Operator while the BOP stack is latched onto the wellhead. The operation is then automatically initiated upon either of the following scenarios:

- Loss of both hydraulic and electric power to the DMAS control pod; or
- Unintended disconnection of the LMRP.

The DMAS control pod will initiate actuation of the Shear Rams 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 BOP stack function, as discussed in System Description and Basis of Design.

Shear Drill Pipe or Tubing and Seal Wellbore – Emergency Disconnect Sequence (BCSF7)

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 LMRP/BOP Connector unlatches, disconnecting the riser from the BOP stack. The sequence is automatic when initiated and must be activated by an Operator, via the Main Control System.

<u>Hang-Off Drill Pipe (BCSF8)</u>

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 Main Control System and by ROV intervention.

<u>Strip Drill String (BCSF9)</u>

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.

6.1.2 Assumptions

It is to be noted that the barrier model for the subsea BOP model is **<u>an example</u>** developed to illustrate how the barrier model template can be applied to a select subsea BOP and **<u>should not</u>** be considered as representative of all subsea BOP 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, Table 5 represents the main assumptions considered regarding the different barrier elements.

Table 5. Subsea BOP Scenario Assumptions – Barrier Elements

Assumption	Barrier Element
• At a minimum, the barrier critical system (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 BOP stack by providing electric power, hydraulic supply and managing communication signal to and from components of BOP Stack. • The Subsea BOP is modeled in detail according to the BOP minimum functionality in response to the overall barrier function. • In any given scenario, the individual barrier critical system/elements may also provide certain shared functionality or may depend on other critical system functionality and performance (interdependencies) that are being used across multiple critical system/elements. • Rig power is considered to be outside of the Subsea BOP boundary	All

Assumption	Barrier Element
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.	
• Annular BOP is Complete Shut Off (CSO) type and capable of sealing on an open hole. • The Annular BOP is assumed to be actuated by the Main Control System only. The ROV can be operated to actuate the Pipe Rams and Shear Rams, if required.	Annular BOP
• Ram lock mechanism only needs to be energized to activate the lock and does not require power to remain locked. • Pipe Rams and Blind Shear Rams have automatic locking mechanism, and closes and locks as part of the "Close" function.	Pipe Ram and Blind Shear Ram
• Sealing is inherent of the hydraulic connector latch and connect function (e.g., LMRP-Lower BOP stack connector and BOP Stack-Wellhead Connector)	Connectors
• The CCU has crossover communications to both the Blue and Yellow Pods.	CCU
• Excluded from the subsea BOP system, considered part of the Mud Circulation system.	Choke and Kill Manifold
• There are two independent rigid conduits and MUX cables used to supply hydraulic power fluid and electric signals to a dedicated control pod (i.e., one to the blue pod and one to the yellow pod)	Rigid Conduits
• The Main Accumulator System is charged and available to supply power fluid to perform the BOP functions on demand. The HPU will not be required immediately to perform the function, but only to recharge the main accumulator system at the pre-defined pressure set point. • The Main Accumulator System consists of surface and subsea accumulators and may require both to function certain stack components.	Main Accumulator System
• The Dedicated Emergency Subsea Accumulator System is shared and able to provide hydraulic power fluid to both the DMAS system and the ROV operated control system.	Dedicated Emergency Subsea Accumulator System
• ROV is fitted with a back-up battery supply.	ROV Power Unit
• The Main Control System is assumed to be a standard MUX system. • The Main 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	Main Control System
• The secondary control system is assumed to be a ROV operated control system.	Secondary Control System

Assumption	Barrier Element
• 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 BOP stack is latched on the wellhead. • Hydraulic Power Unit, Ridged Conduit and Hotlines will not be required for DMAS operation, as accumulators are charged and ready to perform their function. • Actuation of the 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. • No back-up battery supply is assumed for the DMAS control pod.	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 Subsea BOP System.

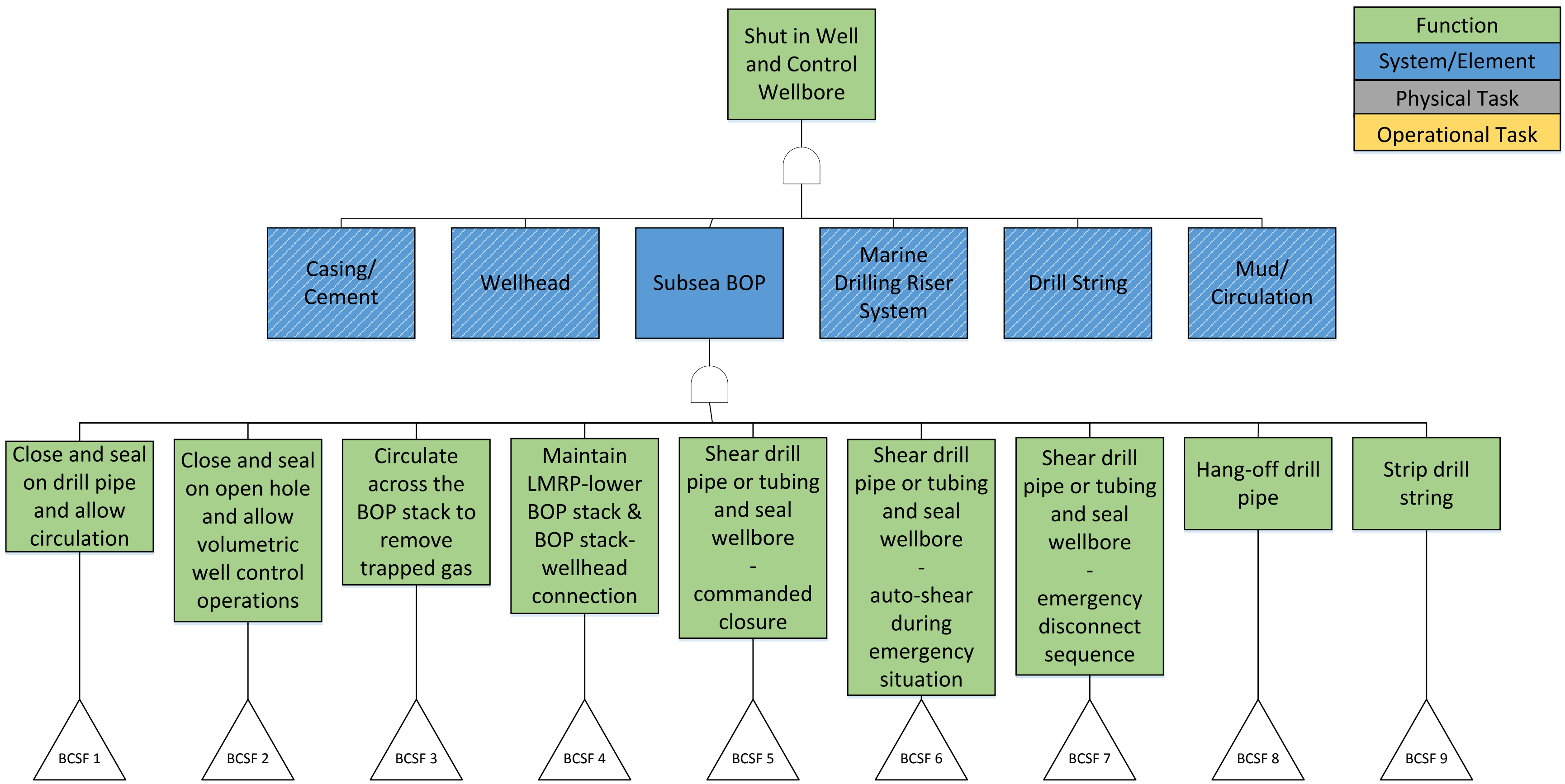

Figure 5. Barrier Function, Barrier Critical Systems and Barrier Critical System Functions

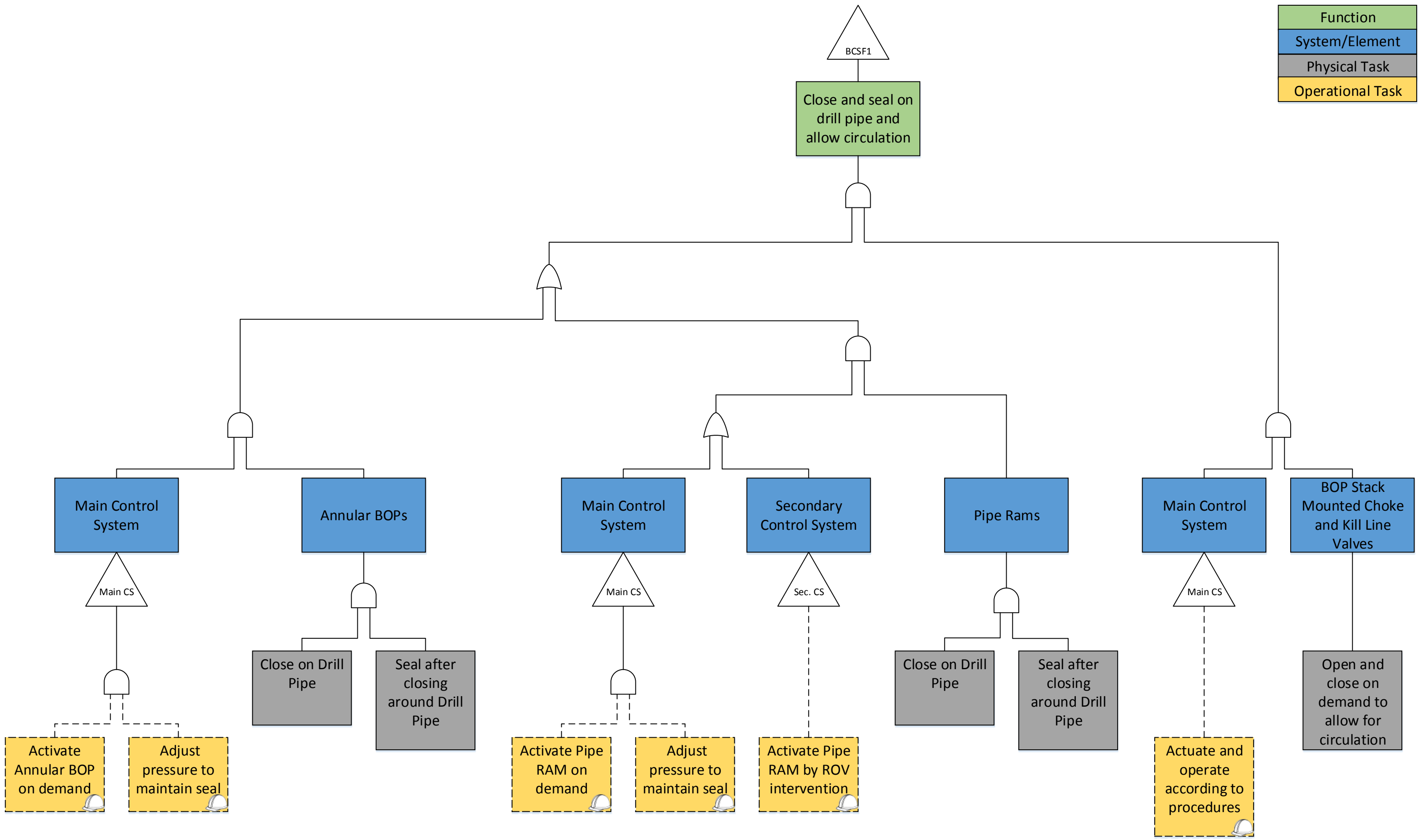

Figure 6. Barrier Critical System Function 1 – Close and Seal on Drill Pipe and Allow Circulation

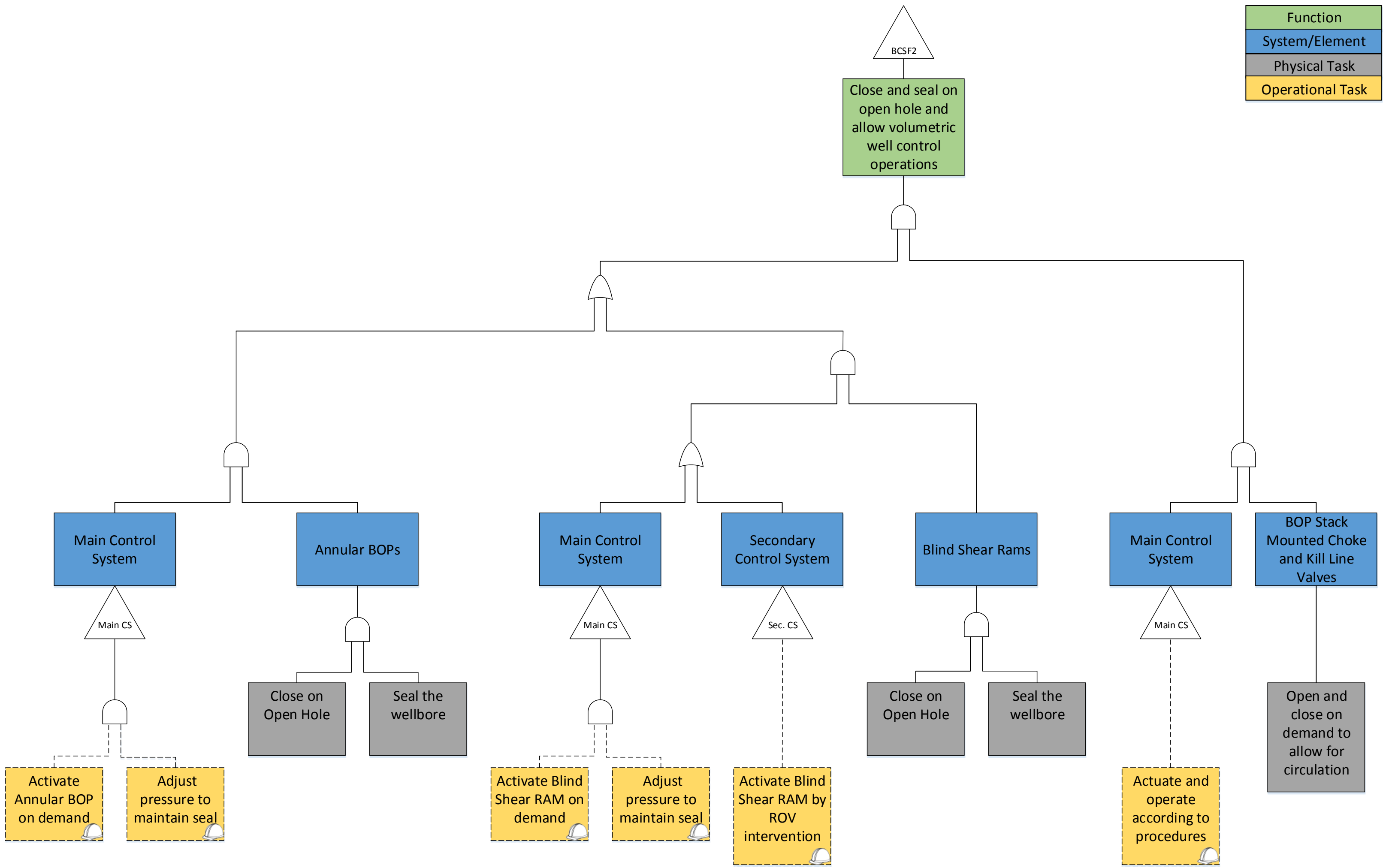

Figure 7. Barrier Critical System Function 2 – Close and Seal on Open Hole and allow Volumetric Well Control Operation

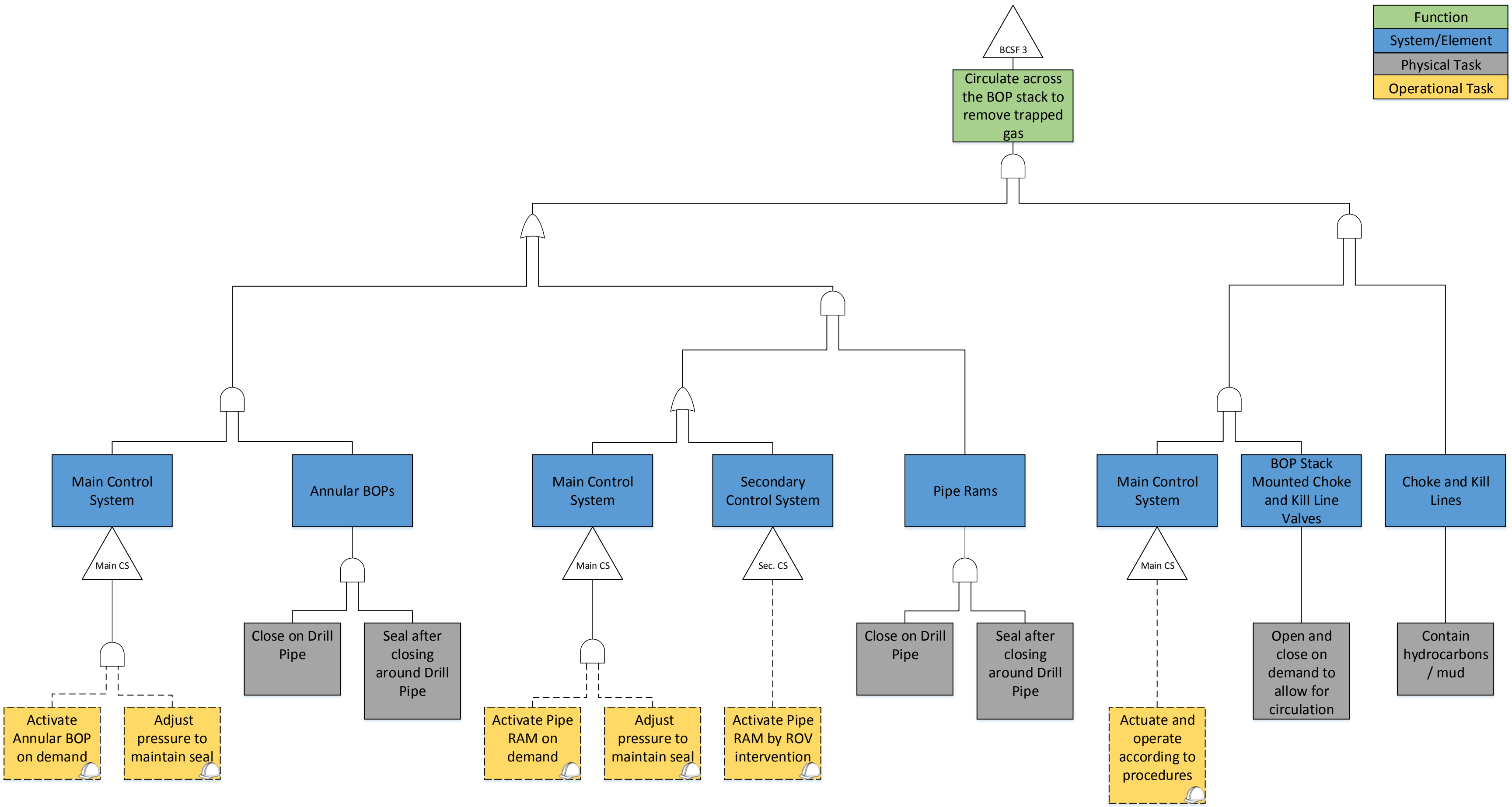

Figure 8. Barrier Critical System Function 3 – Circulate Across the BOP Stack to Remove Trapped Gas

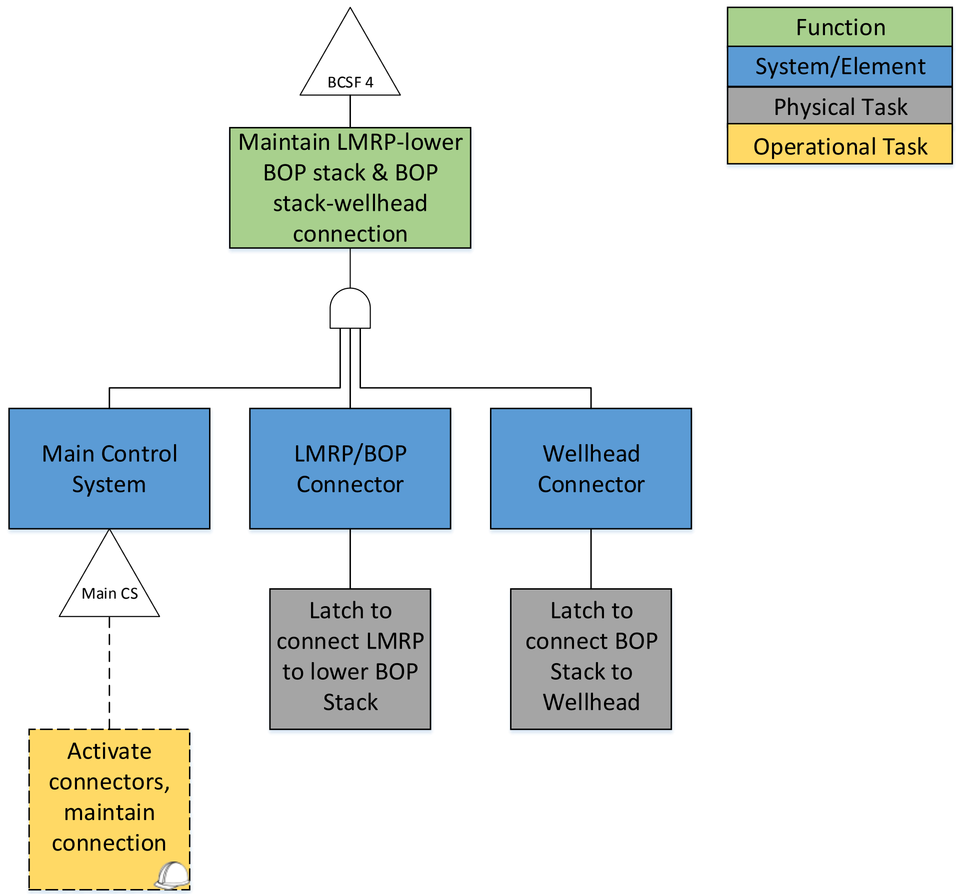

Figure 9. Barrier Critical System Function 4 – Maintain BOP and LMRP Connection

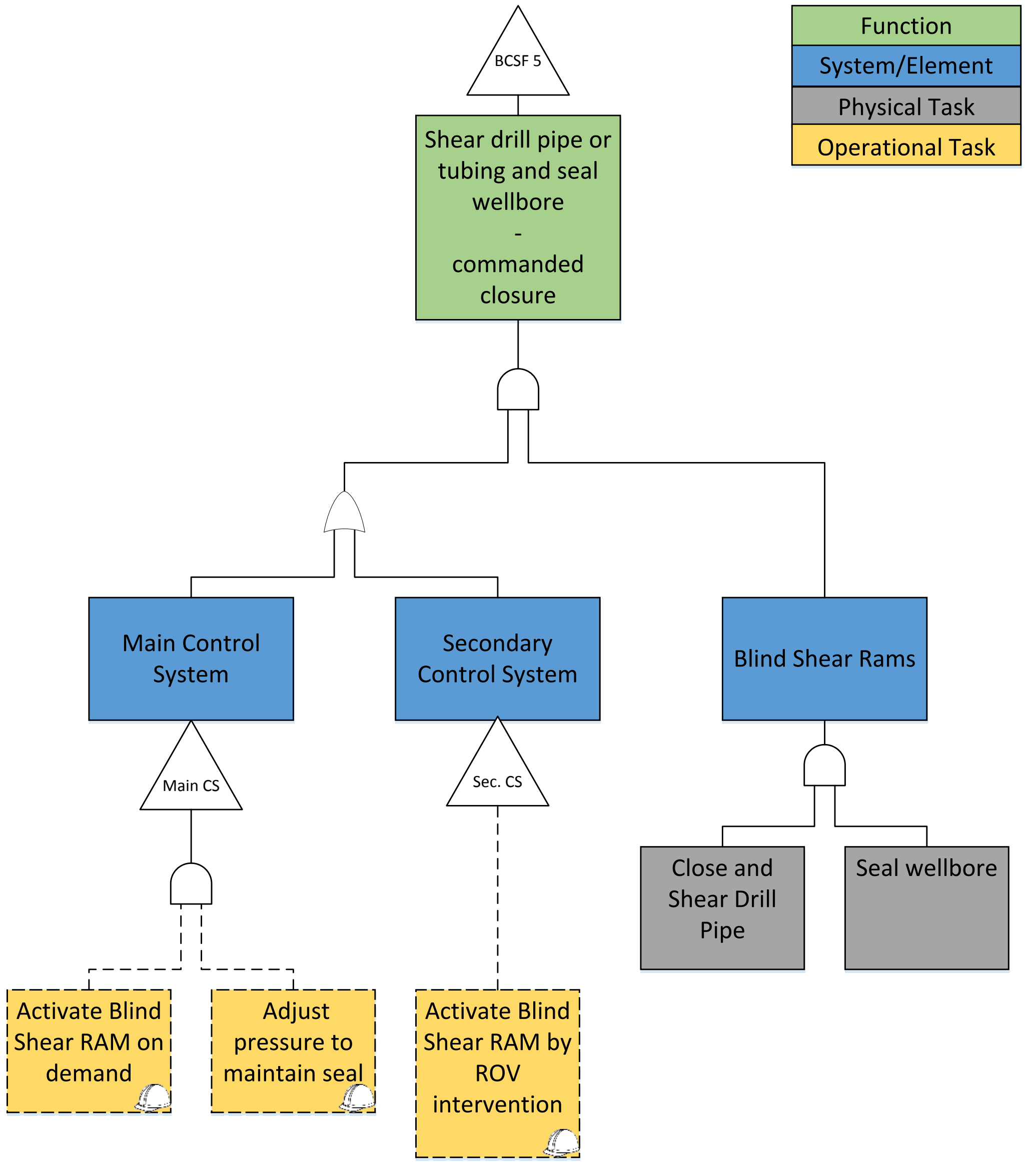

Figure 10. Barrier Critical System Function 5 – Shear Drill Pipe or Tubing and Seal Wellbore – Commanded Closure

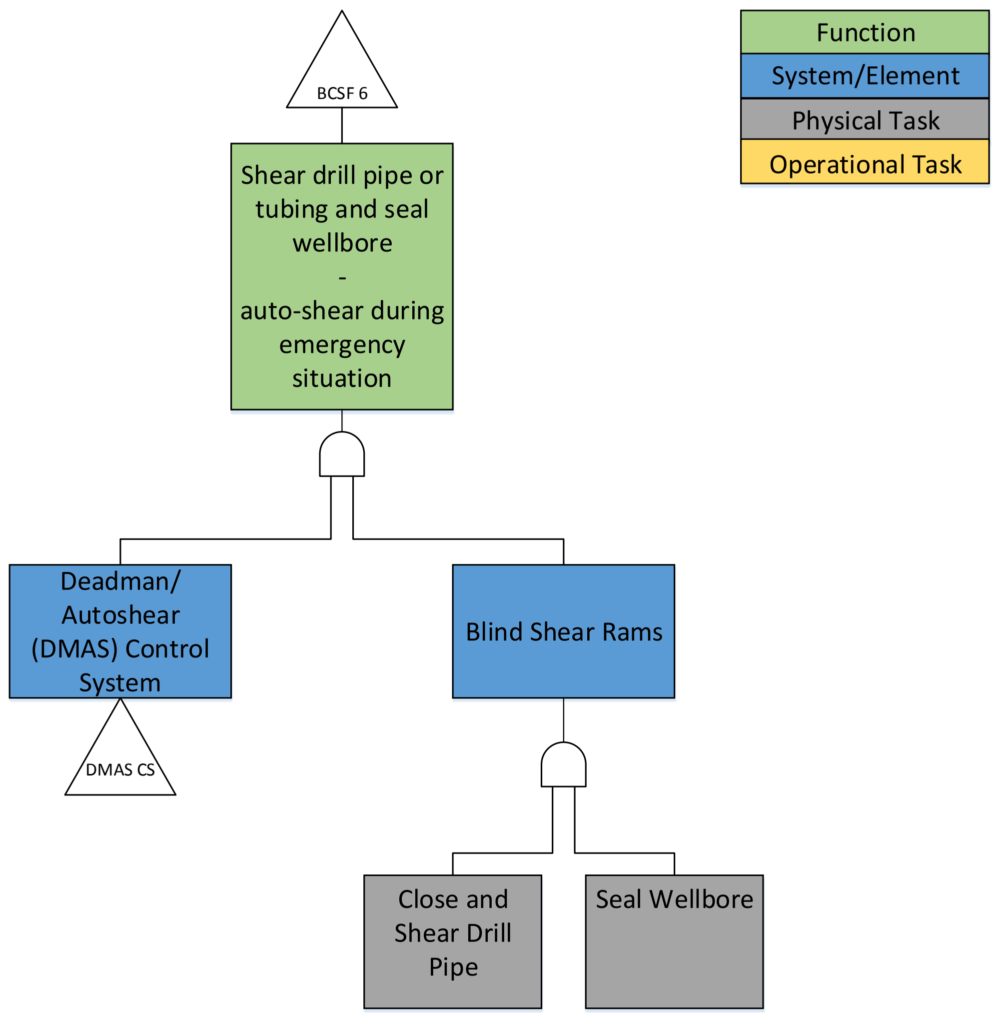

Figure 11. Barrier Critical System Function 6 - Shear Drill Pipe or Tubing and Seal Wellbore – Auto-shear during Emergency Situation

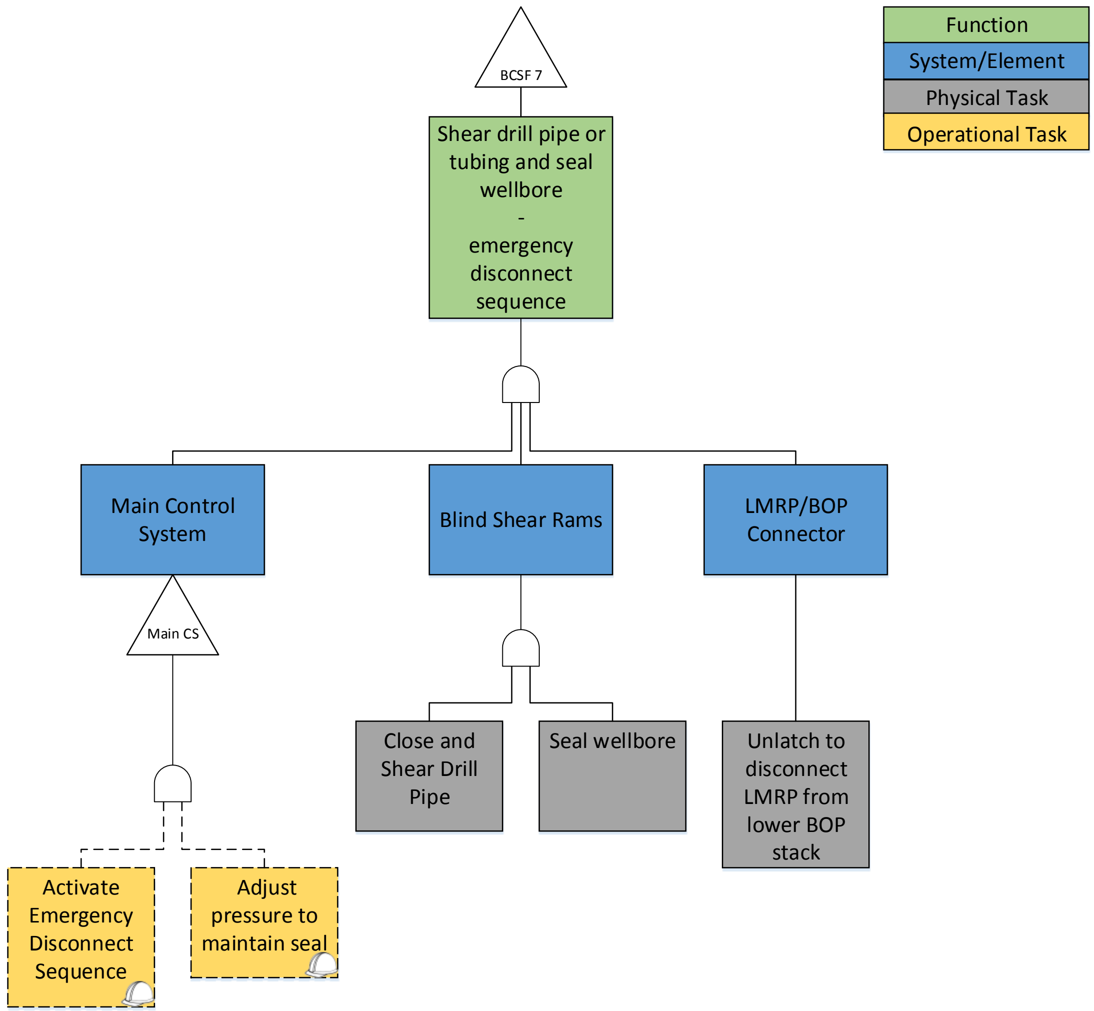

Figure 12. Barrier Critical System Function 7 - Shear Drill Pipe or Tubing and Seal Wellbore –Emergency Disconnect Sequence

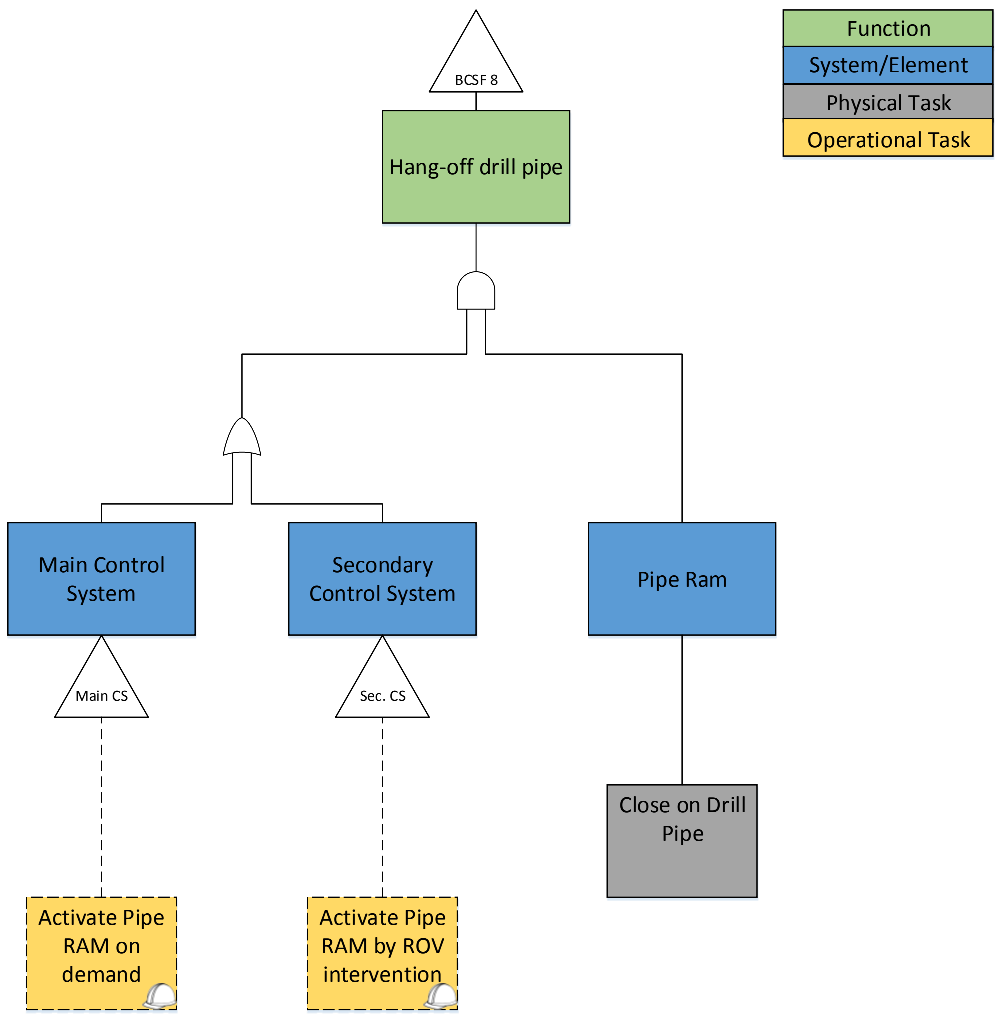

Figure 13. Barrier Critical System Function 8 – Hang-Off Drill Pipe

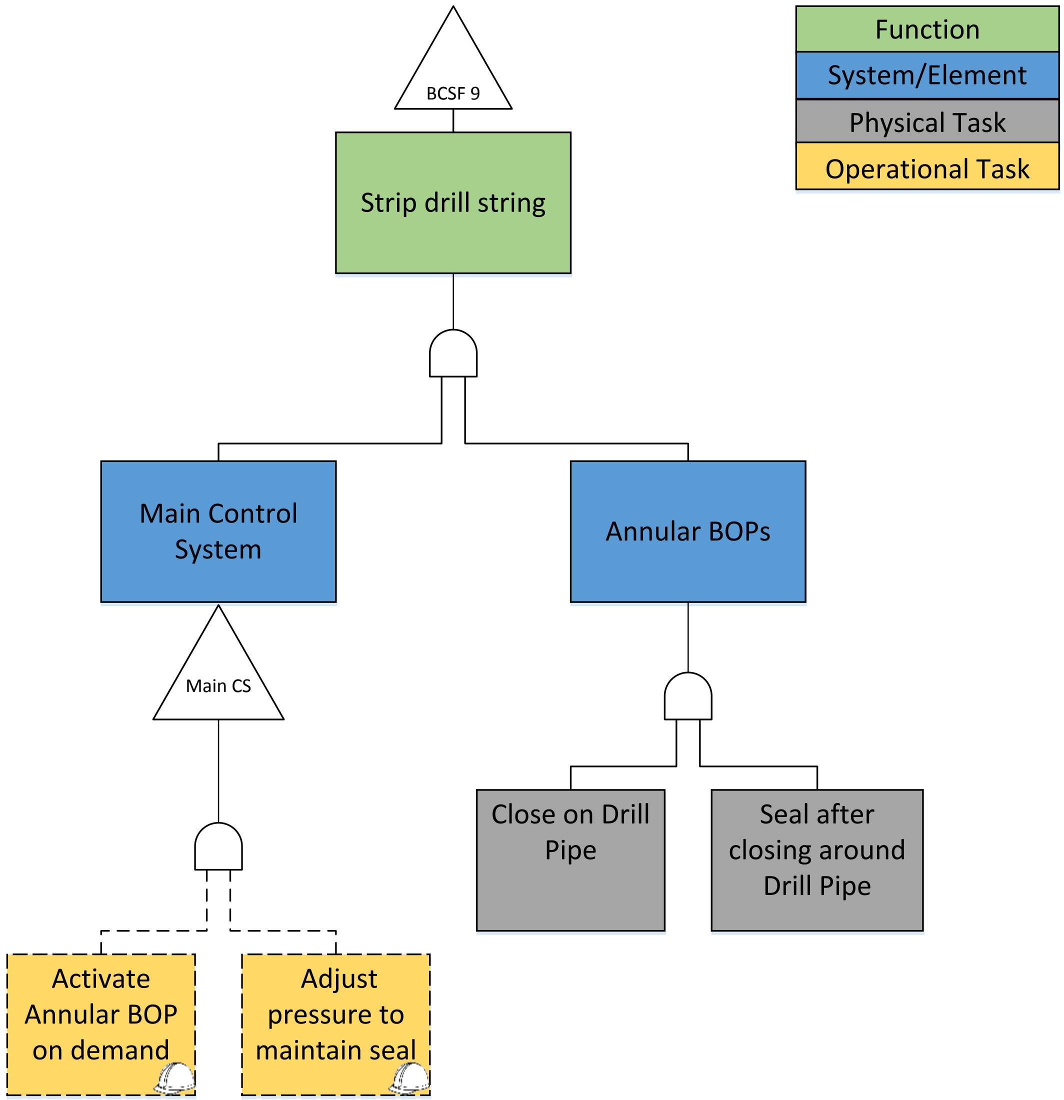

Figure 14. Barrier Critical System Function 9 – Strip Drill String

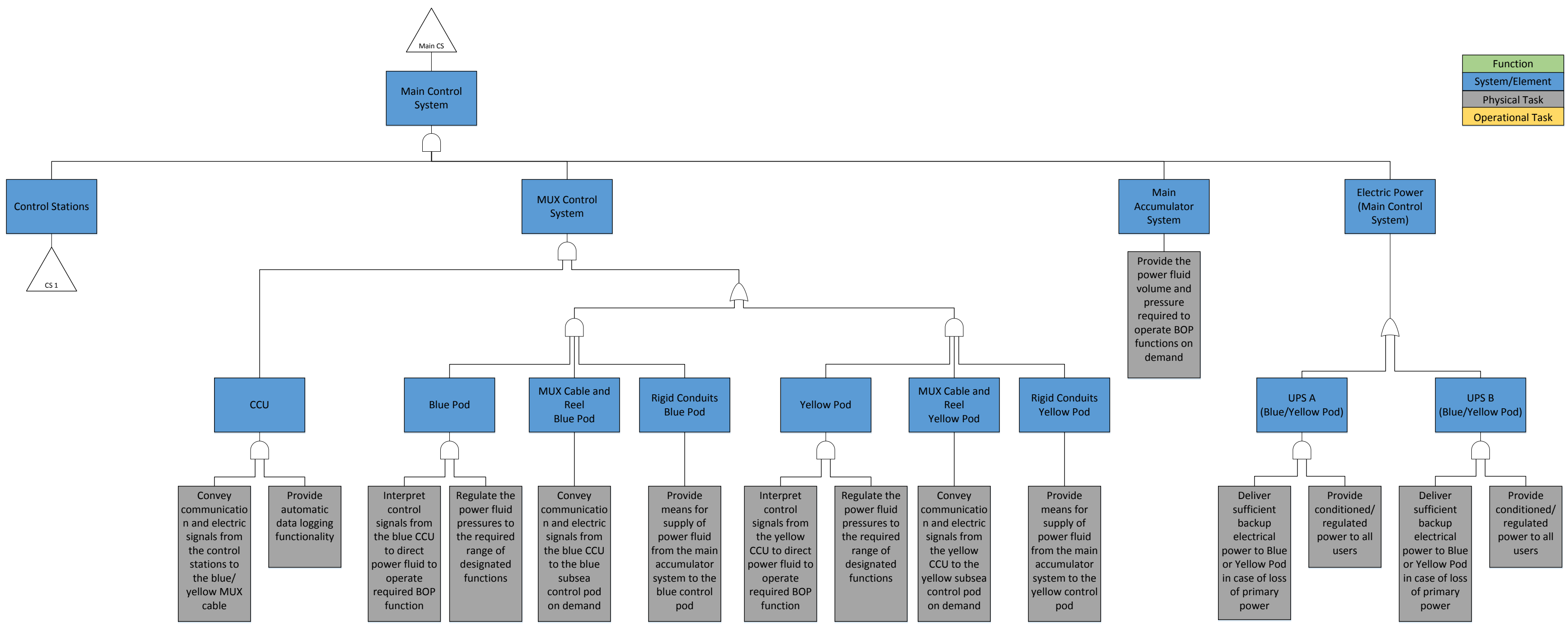

Figure 15. Main Control System – Part 1

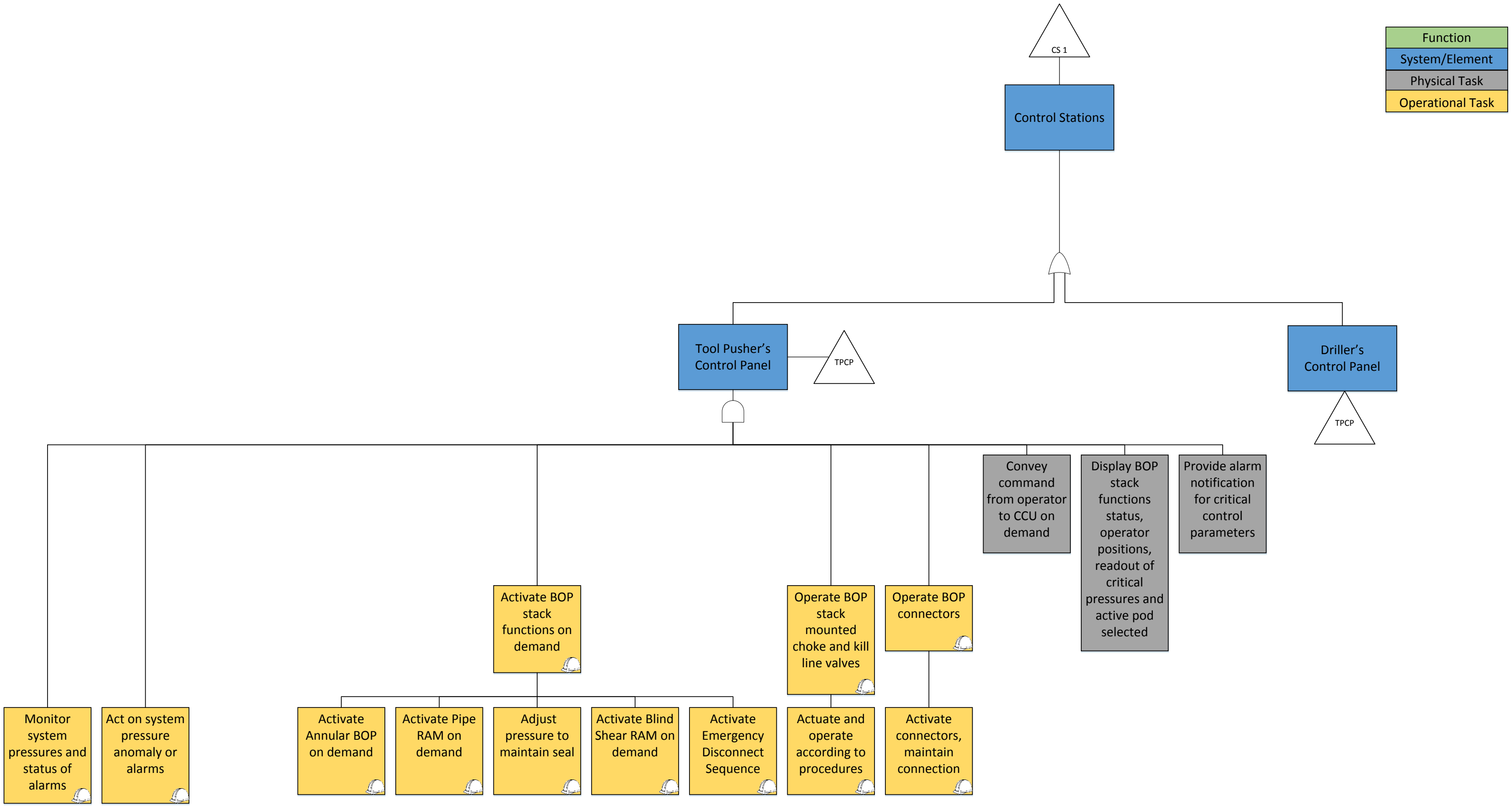

Figure 16. Main Control System – Part 2

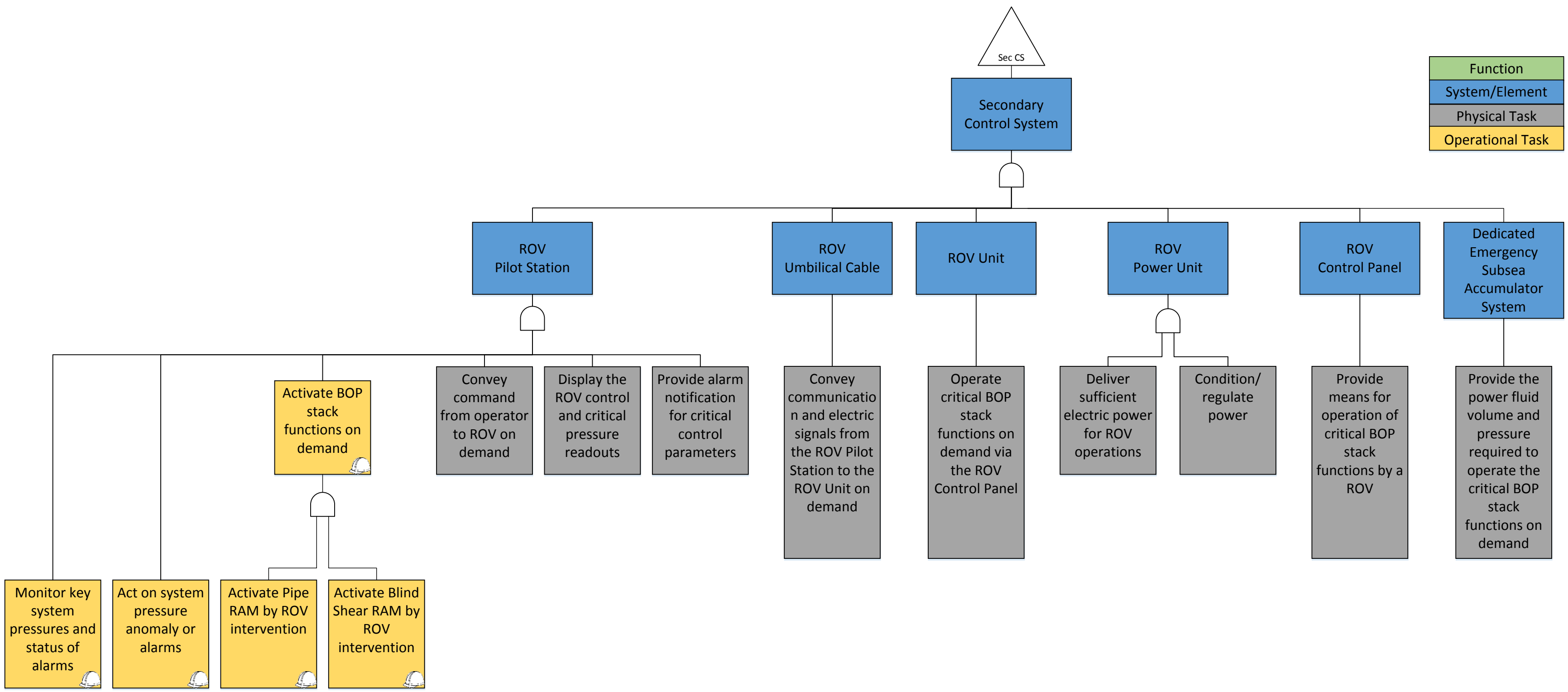

Figure 17. Secondary Control System

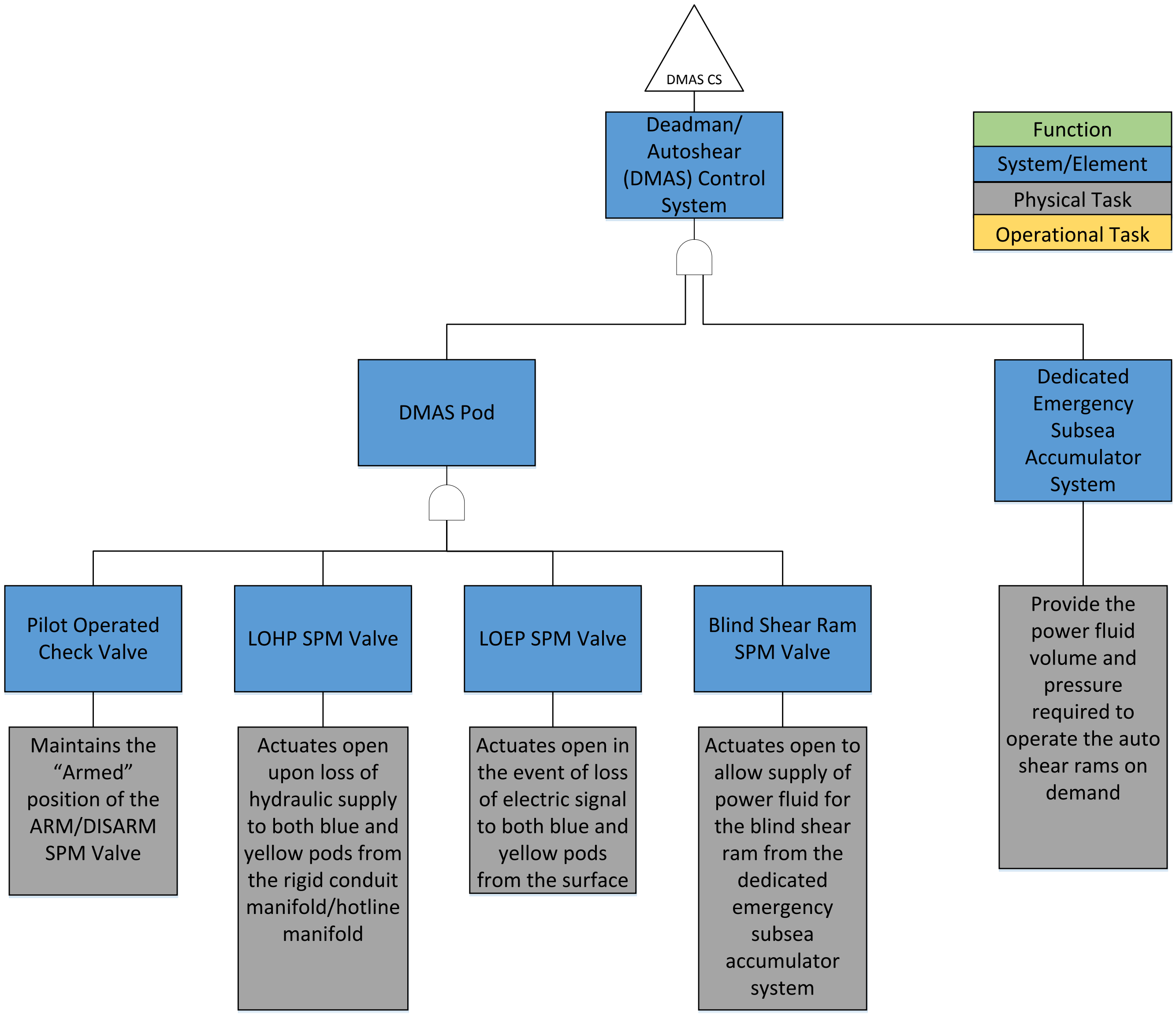

Figure 18. DMAS Control System

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 exist as MS Excel workbooks. Each checklist contains a structure of attributes influencing the performance of the barrier elements made up of 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 for compliance. 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 6 summarizes the barrier elements and the attribute checklists developed for the Subsea BOP 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 6: Barrier Element Attribute Checklists

Barrier Element	Checklist Provided Yes(Y)/No(N)	Checklist (Click to open in MS Excel)
BOP Stack		
– Annular BOPs	Y	Subsea BOP_Annular BOP
– BOP Stack Mounted Choke and Kill Line Valves	Y	Subsea BOP_BOP Stack Mounted Cho
– Choke and Kill Lines	N	NA
– Blind Shear Rams	Y	Subsea BOP_Blind Shear Ram
– LMRP/BOP Connector	Y	Subsea BOP_LMRP/ BOP Connector
– Wellhead Connector	Y	Subsea BOP_Wellhead Conı
– Pipe Rams	Y	Subsea BOP_Pipe Ram
Main Control System		
– UPS A (Blue/Yellow Pod)	N	NA
– UPS B (Blue/Yellow Pod)	N	NA
– Driller's Control Panel	Y	Subsea BOP_Driller's Panel
– Tool Pusher's Control Panel	N	NA
– Main Accumulator System	Y	Subsea BOP_Main Accumulator System
– Blue Pod	Y	Subsea BOP_Blue Pod
– Yellow Pod	N	NA
– CCU	Y	Subsea BOP_CCU
– MUX Cable and Reel (Blue Pod)	Y	Subsea BOP_MUX Cable and Reel
– MUX Cable and Reel (Yellow Pod)	N	NA

Barrier Element	Checklist Provided Yes(Y)/No(N)	Checklist (Click to open in MS Excel)
– Rigid Conduits (Blue Pod)	Y	Subsea BOP_Rigid Conduits
– Rigid Conduits (Yellow Pod)	N	NA
Secondary Control System		
– ROV Power Unit	N	NA
– ROV Pilot Station	N	NA
– ROV Control Panel	N	NA
– ROV Umbilical Cable	N	NA
– ROV Unit	N	NA
– Dedicated Emergency Subsea Accumulator System*	Y	Subsea BOP_Dedicated Eme
DMAS System		
– LOEP SPM Valve	N	NA
– LOHP SPM Valve	N	NA
– Blind Shear Ram Close SPM Valve	N	NA
– Pilot Operated Check Valve	N	NA
– Dedicated Emergency Subsea Accumulator System*	Y	(see above)

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