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Abstract

The world-scale disaster in the Gulf of Mexico on 20 April 2011 drew the attention of the authorities and oil and gas companies to the reliability of the blowout preventer systems. The efficiency of emergency preparedness to operate such systems was also in the spotlight due to several unsuccessful attempts to operate during the accident. Generally, there are three main methods and five sub-methods, which allow controlling the blowout preventer systems when the primary control system is not available. All methods have their advantages and disadvantages in form of cost, availability and reliability. Some of them are independent; some depend either on the blowout preventer configuration and state or on other auxiliary equipment. More detailed analysis and investigation of these methods show that there is still a room for developing of new solutions technologies for emergency controls.

Acknowledgement

This thesis work is my last step towards my master's degree in Subsea Technology and Marine. Before I began my thesis work, I had some limited knowledge and understanding of how the blowout preventers work. However writing this work gave me the full picture of BOP systems and their operation.

Here I would like to express my deepest thanks to my supervisor Eiliv Fougner Janssen for his priceless guidance and help. My thanks goes to people at Oceaneering – Erik Johnsen, Steffan Kruse Lindsø and Nils Helge Sætre for valuable input and information about remotely vehicle operation. In addition, I would like to thank Alexander Sanne at Envirex and Jonny Sanne at Dolphin Drilling for provided help and shared huge amount of information regarding the BOPs and their control systems. Further, I want to thank Terje Aasland, Jarle Salte at Statoil and my colleagues at Nexum Engineering for the general help and information on subsea technologies.

Thanks to PARO software and Nexum Engineering for the provided software that allowed me to create drawings and figures.

Finally, I want to give special thanks to my wife for her understanding of my regular absence and support when I needed it.

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Abbreviations

Abbreviation	Description
ACS	Acoustic Control System
AMF	Automatic Mode Function
BOP	Blowout Preventer
CSR	Casing Share Ram
DWH	Deepwater Horizon
DWP	Dirty Work Pack
EDS	Emergency Disconnect Sequence
FSC	Failsafe Close
gpm	Gallon Per Minute
HP	High Pressure
hp	Horse Power
kW	Kilo watt = 1000 Watt
LARS	Launch And Recovery System
LMRP	Lower Marine Riser Package
LP	Low pressure
MGS	Mud Gas Separator
MUX	Multiplex
ROV	Remotely Operated Vehicle
SBR	Share Blind Ram
SPM	Subsea Pilot Manipulated
TMS	Tether Management System
VBR	Variable Bore Ram

1 Introduction

The Macondo accident in the Gulf of Mexico demonstrated to the world how easy it was to oversee the potential accidents. Accidents happen often because of the vulnerability of safety and emergency systems in oil and gas industry. Detailed and expensive analysis could be performed on the safety systems to ensure their reliability and to secure redundancy. Systems that provide alternative ways to execute different functions could also be deployed at drilling facilities. However, as the overall system size becomes bigger, a number of small and unforeseen defects rises.

Semisubmersible drilling rig Deepwater Horizon was used for drilling and completion operations on the Macondo well. It had several emergency systems deployed. Some of them had high redundancy. Despite that, the result is however catastrophically – several fatalities, loss of facility, loss of company reputation and huge environmental damage. Some of these small defects with huge consequences were found in the blowout preventer (BOP) system after the accident. The time used on the attempts to regain the control over the blowout preventer after the accident was enormous long. None of the attempts to function the BOP valves by the remotely operated vehicles has met with success. This demonstrates how important the alternative ways to function the BOPs are.

This thesis's theme was chosen due to author's high interest in logical controls and relevancy to the current problems in offshore industry. This work will take a closer look at the situations where the BOPs are inoperable from the host rigs and the different methods they can be controlled with. All methods, their description and discussion will be presented in an easy readable manner in form of figures and tables.

2 Method

This thesis will describe and analyze the two last parts of an accident at an offshore drilling facility – total loss of control and post accidental work, specifically emergency operation of a BOP. BOP operation methods that will be discussed here are applicable both for the accidents and generally for the events where the BOP functions should be activated when the system cannot be controlled from the host facility.

Tasks to be performed in the current work:

- Acquire background technical expertise in BOP systems and their controls.
- Acquire background technical expertise in ROV (Remotely Operated Vehicle) systems and their controls.
- Acquire background information on Macondo well accident and similar accidents, where the emergency BOP control was required.
- Discuss the response and work done to get the control over the BOPs in these accidents.
- Develop possible methods to control the BOP in emergencies.
- Discuss and compare different methods systematically.
- Come up with further recommendations.

Most information for this work was found on the web, using the search and databases such as Google Scholar and One Petro. Standards were provided by the university library, however NORSOK standards were free available from the internet. A large input came from the interviews with professionals within oil and gas.

3 Background

The background of this work is a disaster that happened in Gulf of Mexico in April 2010. Eleven people died and a major damage was caused to the environment by the accident at Macondo well. The Macondo well blowout began when the drilling crew of the Deepwater Horizon (DWH) were in the last stages of the temporary well abandoning. The drilling personnel misinterpreted the pressure test results of the well seal integrity at the bottom of the well, believing that cement had sealed the hydrocarbon-bearing zone, while it had not. At that time, the only physical barrier left against uncontrolled well flow was the blowout preventer [1].

3.1 Barriers

We can describe a barrier as something that either prevents an unwanted event to occur or reduces the consequences, in case of an event occurrence. An example of a barrier can be lashings used to secure the load during transport on a trailer. These lashings prevent the load to move or fall from the transporting platform causing damage to itself or surroundings in case of hard breaking or quick turn of the trailer. An example of a barrier that reduces the consequences of an unwanted event can be a firefighting system. When all barriers that should prevent the fire from establishing fails, the firefighting system tries to reduce the consequences of the event fire.

A bow-tie diagram can usually represent complex barrier systems used in oil and gas industry. Unwanted event (incident) is usually placed in the center of the diagram, e.g. Fire/Explosion. Events that trigger the unwanted event are on the left side. Consequences from the occurrence of the center event are on the right side. Barriers that prevent the incident are placed between the triggering events and the center event. Barriers that reduce the consequences of the center event are placed between consequences and the center event.

We can also compare a set of barriers with a Swiss cheese. Holes in the cheese represent faulty or "holes" in the safety barriers. In a case where all the holes of the Swiss cheese slices align in a line, we get occurrence of an undesired event. Figure 3.1 shows faulty barriers in Deepwater Horizon accident.

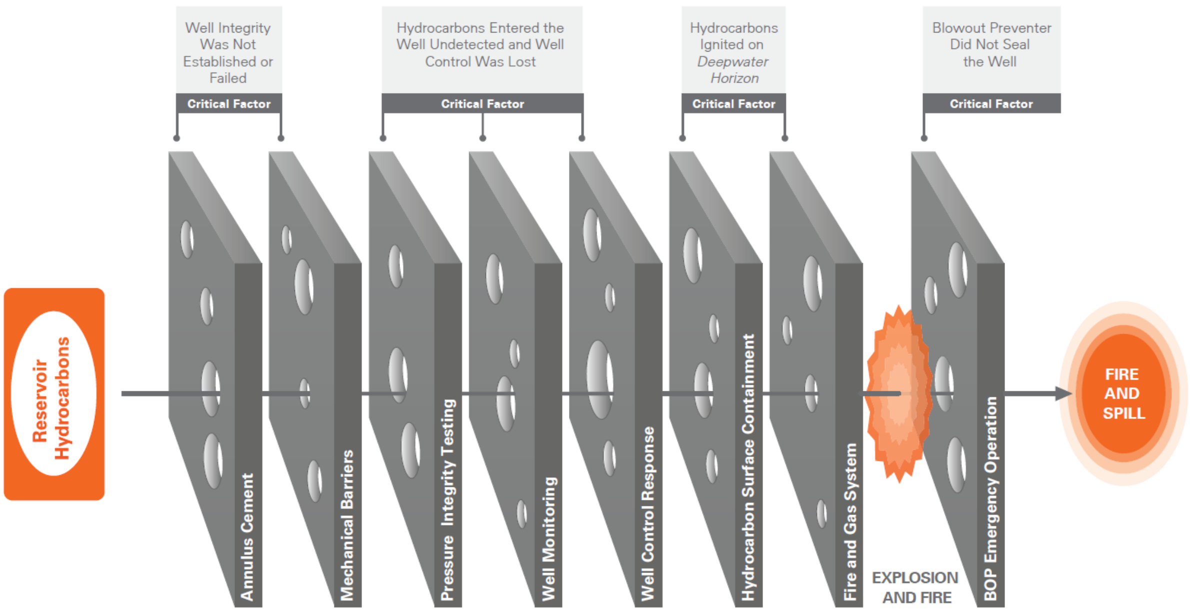

Figure 3.1 – Barriers Breached at Deepwater Horizon accident.Relationships of Barriers to the Critical Factors.
Figure: BP, Deepwater Horizon Accident Investigation Report

Barriers in a well are divided in two categories – primary barriers and secondary barriers. The only primary barrier in a drilling well is a fluid column of drilling mud. All other barriers including the blowout preventer are secondary barriers. Among the eight safety barriers that have been breached at Macondo well accident, the BOP that did not seal the well, played its last role.

In this work, we will concentrate on a BOP as a last safety barrier against blowout, BOP's functions and modes.

3.2 Blowout preventer

> *BOP – equipment (or valve) installed at the wellhead to contain wellbore pressure either in the annular space between the casing and the tubulars or in an open hole during drilling, completion, testing or workover operations. [2]*

BOP stack is as an assembly of several different types of BOPs. In offshore drilling, BOP stack is installed on to the wellhead and connected further to topside through a marine/drilling riser. Blowout preventer stack is a heavy piece of equipment, which requires a lot of effort and time to install or remove. The weight a BOP stack can be over 380 MT and height over 13 m. This indicates how massive this equipment is.

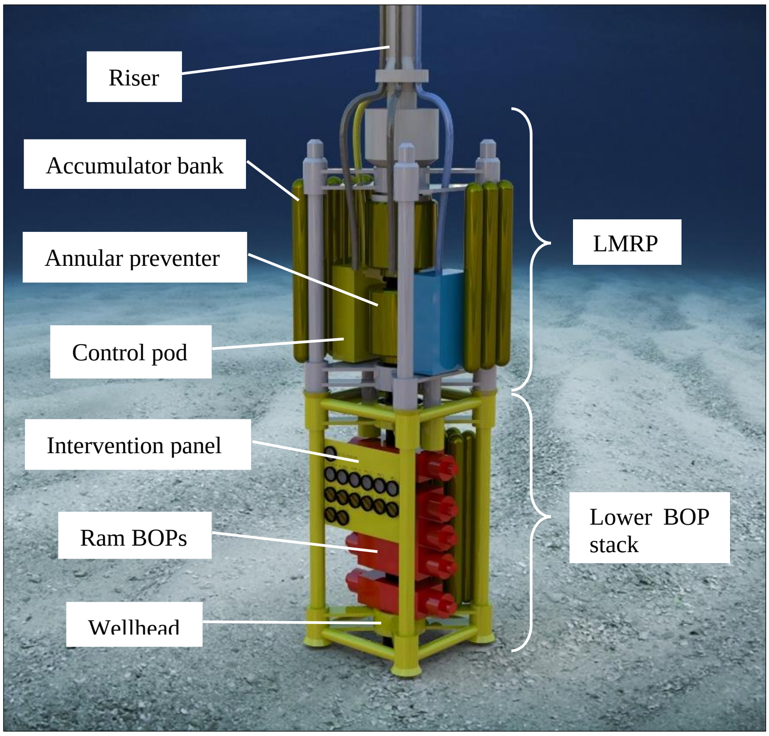

Figure 3.2 – Blowout preventer stack
Figure: Made by author

Blowout preventer stack consists of two main assemblies – LMRP (Lower Marine Riser Package) and lower BOP stack. It can be operated in either normal or emergency modes. The main function for all modes is to seal and control the well. Otherwise, it is also used to test the well integrity. Securing the well is done by closing one of the BOP stack sealing devices around an object running through it or sealing the open hole alone. Different closing mechanisms are used for this purpose.

3.2.1 Lower Marine Riser Package

LMRP is an assembly installed on top of the lower BOP stack. It contains a riser adapter with a flex/ball joint; one or two annular preventers; subsea control pods and a hydraulic connector mating the riser system to the lower BOP stack. LMRP is designed to provide releasable interface between the drilling riser and the blowout preventer in situations that require this type of action, e.g. moving of location due to bad weather conditions; pulling the riser for maintenance etc.

Control pods located inside the LMRP act as a trigger system for the components at the LMRP and the BOP stack – ram and annular preventers, kill/choke valves, hydraulic connectors. These are always installed in pairs to produce redundancy. Lower Marine Riser Package is also an accommodation place for subsea hydraulic accumulators, which store hydraulic power required by emergency functions, e.g. Emergency Disconnect Sequence system and ROV intervention panel.

3.2.1.1 Annular BOP

Annular BOP – is a mechanism that can seal almost around any object running through it. When activated, a rubber "doughnut" is squeezed to the borehole center. Due to elastomer material, the inner diameter of the packer is formed around any object that runs through it to create a seal. Annular BOP can also be used to seal the open hole. Typical specifications of annular BOPs range from 7-1/16" to 21-1/4" nominal diameter, 2000 - 15000 psi, working pressure [3]. This type of closing device is usually located at the top of the BOP stack in LMRP. Two annular BOPs – upper and lower, were installed at DWH BOP stack.

3.2.1.2 Flex joint

Flex joint is used to compensate for horizontal movements of the drilling unit hence reduce the bending moment on the riser. The rotational stiffness of the flex joint is its primary advantage in front of ball joints and ranges usually from 13600 Nm to 108800 Nm, depending on the bend angle.

3.2.2 Lower BOP stack

Lower stack is an assembly that is installed on to the wellhead, and further connected to the riser via Lower Marine Riser Package. Lower BOP stack usually accommodates several sets of rams, kill and choke outlets and valves, hydraulic wellhead connector, subsea hydraulic accumulators and ROV intervention panel.

3.2.2.1 Ram BOP

Ram BOP – is a closing mechanism that uses rams to close the bore or seal around a pipe. There are mainly two types of ram BOPs:

- *Pipe Ram / Variable Bore Ram (VBR)* – are rams with fixed bore diameters that can seal around a specified drilling pipe sizes or narrow range of sizes (Figure 3.3). Several sizes of VBRs are usually stacked together to cover a specified range of drilling strings to be used. Typical VBR pipe diameter ranges are 2-3/8” x 3-1/2”, 3-1/2” x 5”, 5” x 6-5/8”.

a) **b)**

Figure 3.3 – VBR seals around a pipe. Same VBR packer seals around different pipe diameters: a) Small diameter pipe b) Larger pipe diameter.
Figure: Shyne Coleman

- *Share Blind Ram (SBR)* – are rams that able to cut a tubular[1], which runs through a BOP and seal the well bore. SBRs differentiate in bore diameter, working pressure and the nominal tubular size cutting ability. SBRs are not designed to shear the drill pipe at the tool joint area. That is why a precise control of tool joint position is crucial safety ability under drilling operations. SBR has two operating modes – high pressure (HP) mode and low pressure (LP)

[1] Tubular refers to drill pipe, production tubing, landing string, wire line or coiled tubing.

mode. LP mode is used when the BOP is operated in normal mode to seal against open hole well. HP mode is in use when a tubular have to be sheared, thus in emergency mode.

Casing Share Ram (CSR) is a subtype of SBR, which is able to cut the large diameter well casing. However, CSR does not seal the well. Upper portion of the sheared casing needs then to be pulled above the SBR BOP in order to seal the well.

In 2010, T3 Energy Services introduced a new shear type of ram called Shear All Ram (SAR). According to T3 Energy Services, SAR is able to cut through any size and type of casing and drilling strings [4].

All ram-type preventers are also equipped with locking mechanism that prevents opening of the ram unintentionally. These locking mechanisms are usually automatic, and lock the ram in its position after the actuation of the ram. There are two main types of locking mechanisms – wedge locks and multi-position ram locks.

A summary of BOP types is outlined in Table 3.1.

Closing device	Seals around tubular	Seals open hole bore	Shears tubular	Benefits/Drawbacks
Annular	X	X		Seals around any object; Maximum working pressure reduces with reduced tubular diameter; Commonly closed first under well control activities.
Pipe ram	X			Unable to seal open well bore.
VBR	X			Seals around narrow range of tubular diameters; unable to seal open well bore
SBR		X	X	Cannot shear tool joints or casing; seals the well.
CSR			X	Able to shear casings; does not seal the well.

Table 3.1 – BOP types and their appliance

NORSOK D-001 6.35.4 specifies the minimum subsea BOP stack configuration as follows [5]:

- One annular preventer (two for deep water applications [6]);
- Two shear rams (where at least one is capable of sealing);
- Two pipe ram preventers;

All ram BOPs are often placed in a lower BOP stack assembly, while annular preventers are part of the Lower Marine Riser Package.

3.2.2.2 Choke/Kill and auxiliary lines

All blowout preventers are supplied with choke and kill line outlets. These are connected with topside by means of separate lines running along the drilling riser. Choke/kill lines are used to control the pressure in the annular space of the well bore. Heavy, large density, drill mud (kill mud) is usually pumped in to the well through a high-pressure kill line in case of a kick to balance the well. Choke line is used to bleed off the excess pressure in the annulus either to the Mud Gas Separator (MGS) or overboard. Both lines are also used to perform various tests or mud circulation activities. Auxiliary lines can comprise mud-boost line[2], air-inject lines[3] and hydraulic supply lines [7].

NORSOK D-001 6.35.4 specifies the minimum requirements for choke and kill lines for BOP systems [5]:

- Two choke line outlets;
- Two kill line outlets;
- Four kill failsafe close valves;
- Four choke failsafe close valves.

DNV OS E101 (pp. 34) [8] specifies following:

- Choke and kill outlets to be fitted with two fail-safe close valves in series.
- Shear blind rams to be able to shear the tool joints. If not, lowering and lifting of main hoist system to be possible.
- Pipe rams to be designed for any possible hang off loads.
- Shear or blind ram BOPs to be fitted with mechanical locks preventing unintended opening.
- LMRP operation should be available from two locations on the rig. Latch and unlatch functions should be redundant using two independent mechanisms.

Figure 3.4 shows an overview of the main components in a BOP system.

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[2] Mud-boost lines are used to inject drilling fluid just above the BOP stack to increase the drilling fluid, return flow velocity in the annular space of the riser.
[3] Air-inject lines are used to supply air for the air-can buoyancy elements along the drilling riser, if such used.

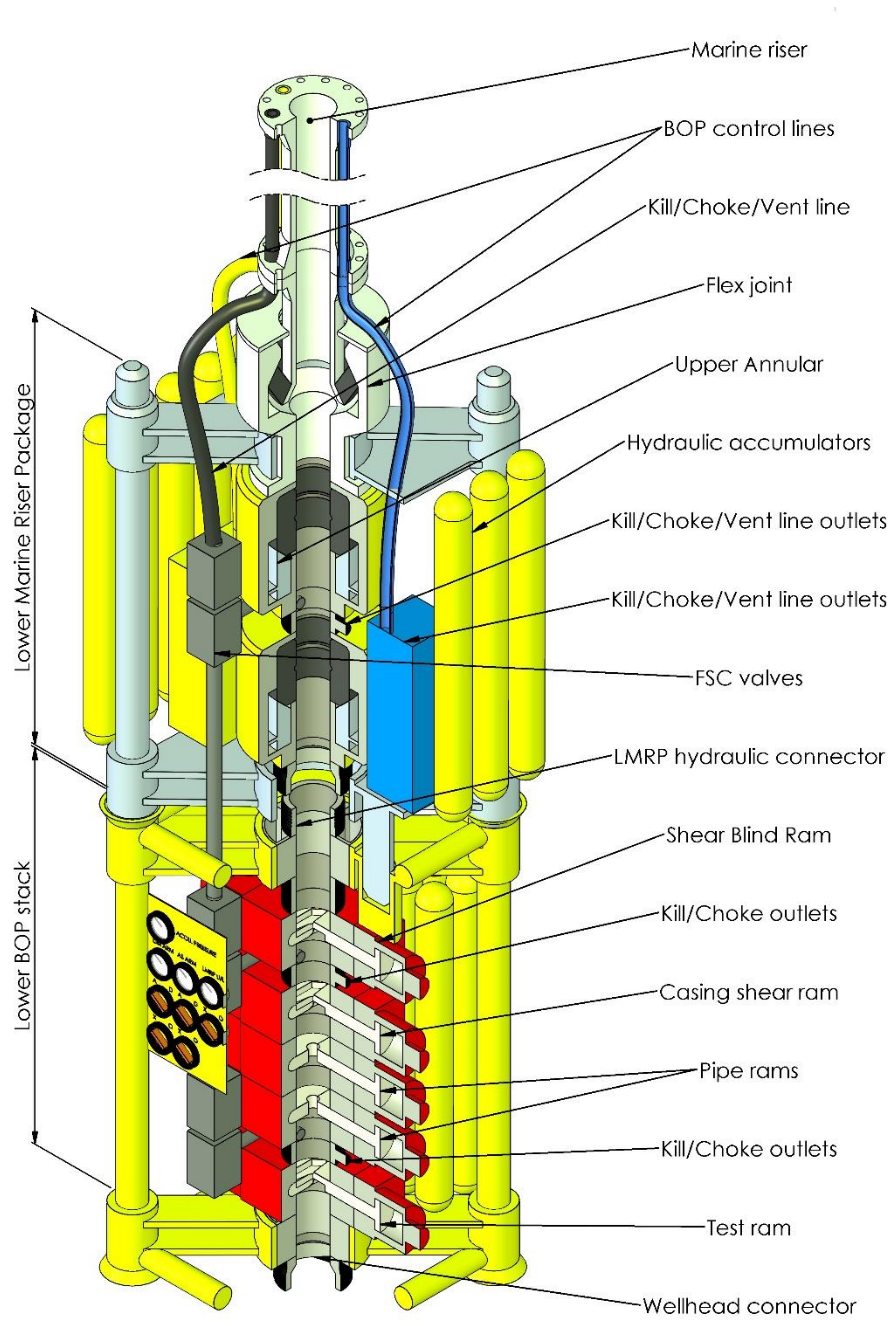

Figure 3.4 – Main components of a BOP system
Figure: Made by author

3.2.3 BOP Control systems

All component of a BOP system are hydraulically operated. In order to deliver hydraulic power to a correct component under correct pressure, control systems are used. Two main types of control systems currently exist – straight hydraulic (Figure 3.5) and multiplex (MUX). Both systems are indirect pilot-operated systems. This means that operating a function at the surface does not operate the BOP system directly, but sends pilot signals to the valve, that allows the BOP component to receive the hydraulic power.

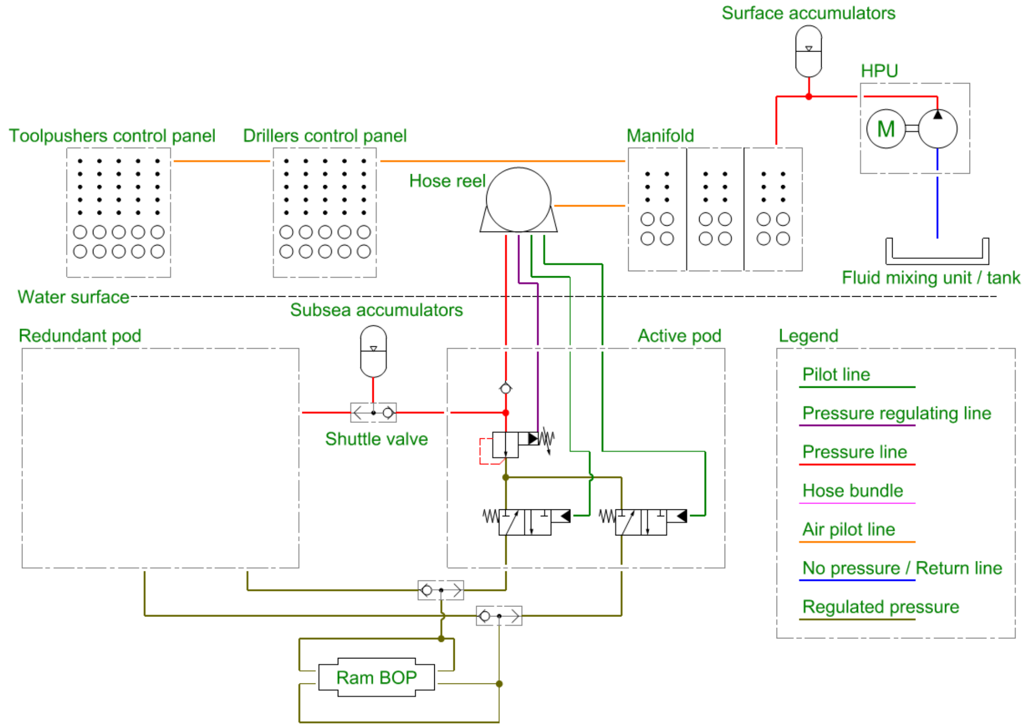

Figure 3.5 – Simple diagram of a straight hydraulic control system
Figure: Made by author

The main difference between these two systems is that straight hydraulic system sends pilot hydraulic signals directly from the surface down to the control pods, located at LMRP. MUX control system is usually used on deep-water and dynamically positioned drilling rigs, whether straight hydraulic system is used on older ones, moored drilling rigs. Multiplex system sends coded signals by electronic means from surface to control pods. Control pods in their place decode the signal and after verification by reciprocal transmission to the surface, targeted solenoid valves are being activated, allowing the hydraulic pilot signal to be send activating the desired function[4]. MUX system makes the pilot signal to travel much shorter way, comparing to the straight hydraulic system, where the pilot signal have to travel the whole water depth increasing the response time.

[4] Operation of kill and choke valves, latching and unlatching the LMRP, opening and closing each set of ram preventers, locking and unlocking the rams, opening and closing annular preventers, operation of the control valves inside the conduit manifold, setting the pressure regulators etc.

Both systems consist of surface and subsea control equipment connected together by lines running along the riser. Surface equipment comprises two independent control panels, usually located at different locations on the rig – drillers cabin and tool pushers office. A hydraulic High Pressure Unit (HPU) together with a hydraulic accumulator bank supplies the needed hydraulic power for the control- and BOP systems. Straight hydraulic systems have a pilot manifold that controls and sends hydraulic pilot signals to the subsea control pods. In its place, an electronic central control unit is used in multiplex control systems. It sends electric signals to the subsea mux electronic packages, ref. Figure 3.6.

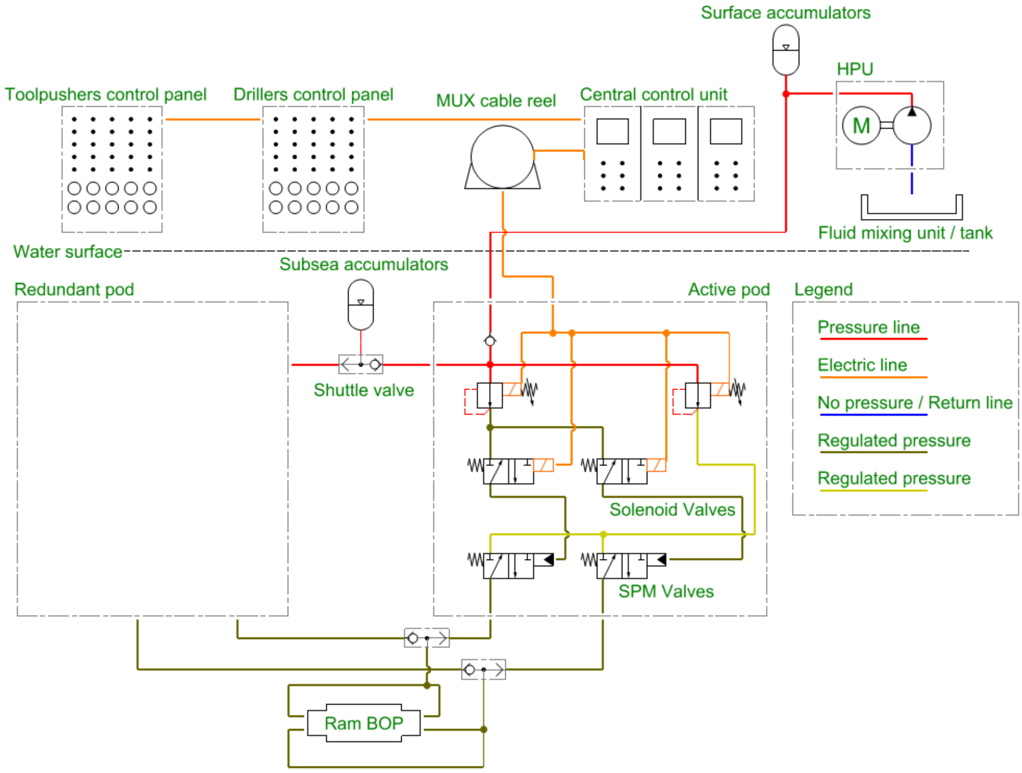

Figure 3.6 – Simple diagram of a multiplex (MUX) control system
Figure: Made by author

As mentioned above, subsea control equipment includes a pair of subsea control pods, that based on the pilot signals received from the surface, activate needed functions of the BOP stack or LMRP. Subsea accumulators are mounted on either LMRP, lower BOP stack or both. There are several reasons for installing subsea accumulators. They can provide additional source of independent hydraulic power supply in case of emergency or primary supply failure; reduce equipment response time for both pilot and main hydraulic circuits.

To increase redundancy of the control system, a pair of dedicated hydraulic lines run from the surface to the LMRP. For straight hydraulic system, these lines are umbilicals, usually consisting of 1” main hydraulic supply hose in the center, and depending on the number BOP functions, number of 3/16” hydraulic hoses around it. Two electric cables follow the riser from the cable reels topside to the control pods subsea in MUX control systems. Refer to Table 3.2, Figure 3.5 and Figure 3.6 for a clear overview.

Controls location	Straight hydraulic	Multiplex
Topside controls	Electric signals are sent from the drillers or tool pushers control panels to the solenoid valves inside the electric junction boxes at the HPU. They supply air to pilot valves and pilot regulators inside the pilot manifold. Air-activated pilot valves provide hydraulic signals to the subsea pilot manipulated valves (SPM) through an umbilical	Electric signals are send from the drillers or tool pushers control panels to the central control unit. Signals are then encoded and sent to the subsea control pods via a pair of MUX electric cables.
Subsea controls	Hydraulic pilot signals received from the surface activate SPMs, allowing the hydraulic power from the main line to the desired BOP function.	Subsea control pod decodes the signals and activates the targeted solenoid valves. It allows the hydraulic pilot lines to activate targeted SPMs. When SPMs are activated, one of the sides of the hydraulic component pressurizes and the other vents.
Surface power supply	HPU supplies the pilot lines with 2000 psi and the main power supply line with 3000 psi.	HPU supplies the pilot lines with 3000 psi and the main power supply line with 5000 psi.
Subsea power supply	Accumulators and ROV intervention	

Table 3.2 – Comparison of two main types of control systems

3.2.4 BOP Emergency functions

As the BOP is the last mechanical barrier in the event of blowout, it is loaded with several emergency functions.

3.2.4.1 Emergency Disconnect Sequence

EDS – Emergency Disconnect Sequence is a programmed sequence of commands sent to the control pods from the topside after an EDS button was pushed. Number and type of functions included in the sequence differs from the operator to operator. However, it includes some fundamental functions. Primary functions of the EDS are to secure the well (closing the shear blind ram) and to disconnect LMRP in case of inability of the rig to maintain its position or during other emergencies. Other functions such as close/block of choke and kill lines, retract the pod stingers, unlatch choke and kill connections as mentioned above are rig/operator dependent. A number of functions of the EDS affects also the total response time of the sequence. Normally it varies from 30 to 90 seconds [9]. In BOP systems equipped with autoshear system, disconnection of the LMRP can be done prior to activation of the shear blind rams.

3.2.4.2 Autoshear systems

Autoshear systems are designed to activate and close the shear blind ram in the event of disconnect of the LMRP from the lower BOP stack. The hydraulic power is then supplied from the local storage – stack mounted accumulators.

3.2.4.3 Automatic Mode Function (AMF) / Deadman system

AMF function closes the shear blind ram only if all three conditions are simultaneously satisfied:

1. Loss of electrical supply to the control pods
2. Loss of hydraulic supply to the control pods
3. Loss of control signal to the control pods

3.2.4.4 Automatic disconnect function

Automatic disconnect function is triggered when the preset riser angle is achieved. This function is similar to autoshear system; however, the trigger mechanism is different.

3.2.4.5 Acoustic control systems

Acoustic control systems are used as a backup systems to be able to send a number of specified commands to the stack mounted control pod in the event when all other communication means are absent. Acoustic systems can also be supplied with a dedicated hydraulic accumulator. The selected functions such as unlocking of riser connector, activating of shear blind ram and closing of middle and upper rams are typically included in the list of emergency functions of acoustic control system.

3.2.4.6 ROV operated functions

Critical functions, such as shear rams, one pipe ram, ram locks (if applicable) and unlatching of the LMRP can be activated with the help of a ROV. Connection between the ROV and the BOP stack is usually made through a single ported hotstab-receptacle interface. The hydraulic power supply can be provided by means of the ROV hydraulic system, hydraulic system at the BOP stack (stack-mounted accumulators) or by means of the separate hydraulic system at the well site.

A dedicated emergency accumulator system may be used for primary emergency functions such as AMF/Deadman or autoshear. In addition, secondary emergency control functions and systems may use a dedicated accumulator system, e.g. acoustic systems, ROV intervention systems.

3.3 Remotely Operated Vehicle

Remotely operated vehicles are divided into several categories according to their capabilities and target usage. NORSOK U-102 classifies ROVs into three groups [10], ref. Table 3.3.

ROV Class	Class description
Class I	Pure observation
Class II	Observation with payload option
Class III	Work class vehicles

Table 3.3 – NORSOK U-101 ROV classes

Class III vehicles are the biggest type. These vehicles are able to carry large loads of equipment (over 200 kg for Class III B) and supply it with power. Class III ROVs has two manipulators in front of the vehicle to perform tasks requiring lifting, grabbing, rotation etc. One of these arms is called grabber, the other one is working manipulator. NORSOK U-101 specifies the minimum requirements for these arms in form of number of functions, outreach and power.

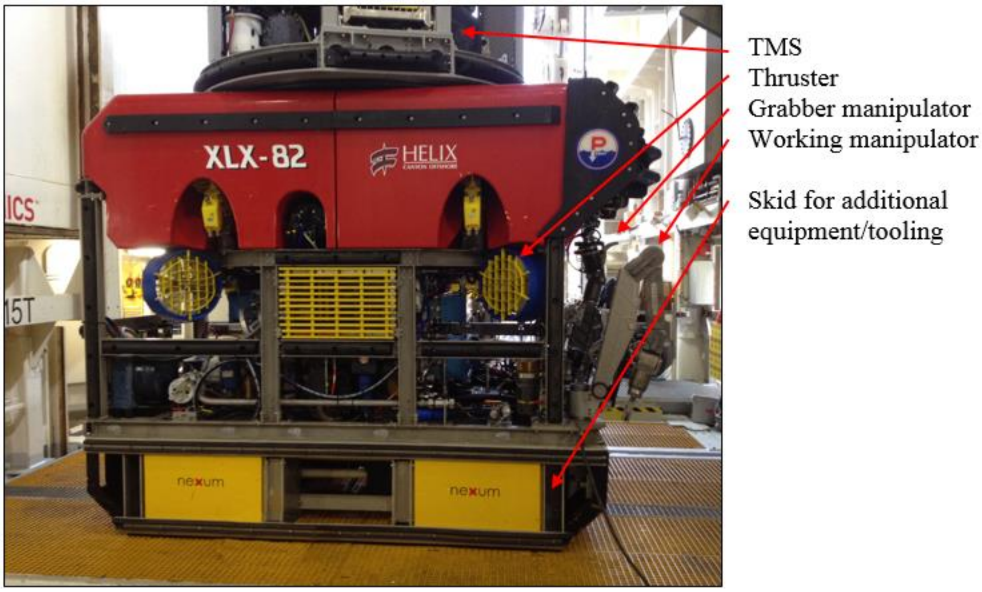

Figure 3.7 – XLX 200 equipped with a skid
Photo: Taken by author

Usually, manipulators and thrusters are powered by hydraulics. Since the vehicle is equipped with one or two HPUs, thrusters and the large amount of the manipulator functions it requires valvepacks to be installed. A number of solenoid pilot valves resides inside the valvepacks and allow control of each specific function using one power source. Valvepacks are supplied with hydraulics from the main HPU and are controlled via electric signals from the ROV control rom topside. Work class ROVs are also equipped with an additional valvepack, which can be used for auxiliary equipment and tooling, ref Figure 3.8.

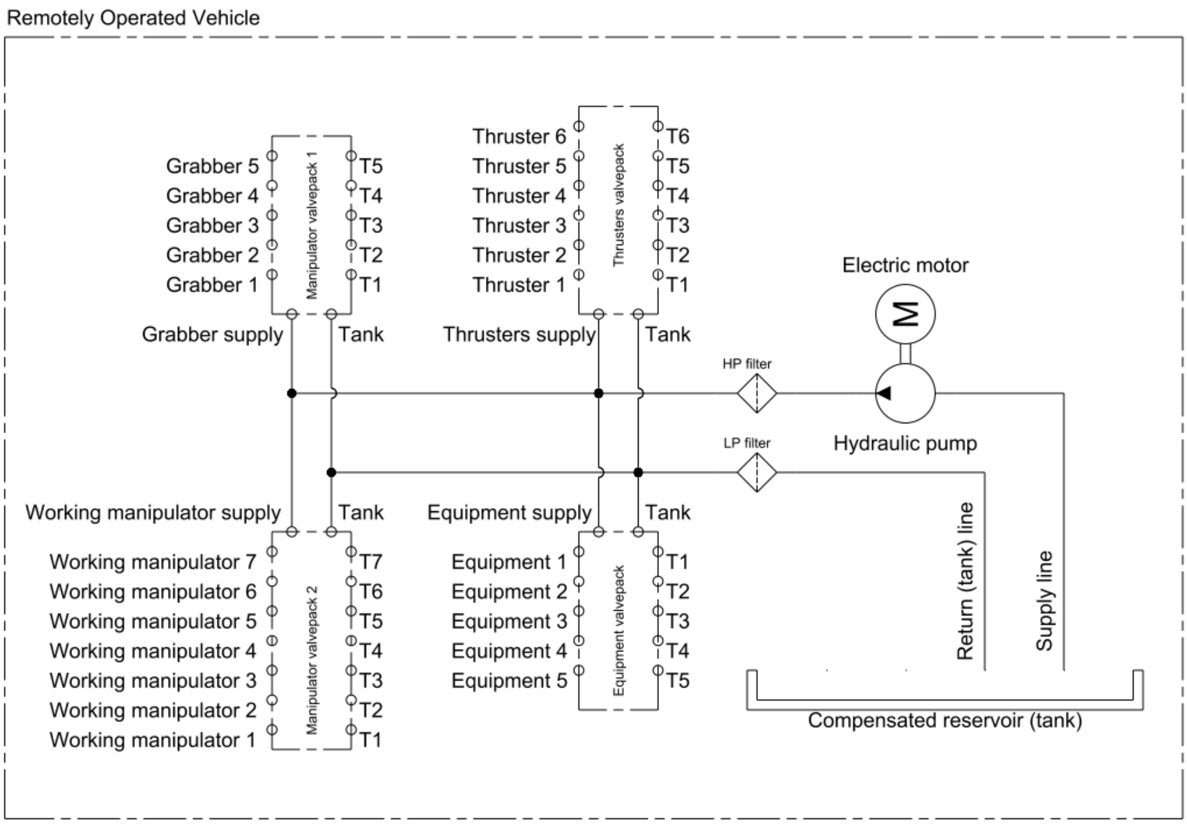

Figure 3.8 – Simple hydraulic schematic of an work class ROV
Figure: Made by author

Compensators are used for hydraulic fluid storage (tank). Compensators provide pressure compensation for the water depth gradient, and usually comprise a dynamic reservoir preloaded with a spring. The reservoir can also be made of an elastic material such as rubber. Typical compensator volumes installed on work class ROVs are in range of 20 liters. To extend the hydraulic volume capacity of the ROV “belly” skids can be used. Skids can also be equipped with other miscellaneous equipment such as Dirty Work Packs (DWP), valvepacks and payload baskets for tools. DWP is a hydraulic motor operated by the ROV hydraulic supply, running a hydraulic pump. DWP provides a separate hydraulic circuit using dedicated hydraulic fluid storage. This allows the ROV hydraulic fluid to stay clean when using the auxiliary tools or stabbing into subsea equipment with a hot stab.

4 Three case studies

4.1 Case 1 - Deepwater Horizon

Deepwater Horizon accident occurred on 20 April 2010, when the rig was preparing the exploration well to temporary abandonment. Due to several factors (e.g. bad well integrity and poor well control management), reservoir fluids managed to pass the BOP, enter the riser and escape to the rig. Later, hydrocarbons were ignited, what lead to rig sinking and uncontrolled blowout subsea.

4.1.1 BOP system configuration

The LMRP at Deepwater Horizon included two Cameron 18 ¾", 10K annular preventers – upper and lower [11]. Lower annular has been modified into "stripping" annular preventer. This allowed the drill crew to strip the drill pipe while having the lower annular closed. However, this change reduced its rated working pressure from 10000 psi to 5000 psi. Four 60-gallon hydraulic accumulators were installed on the riser package to compensate for the delay in response in control system [12]. These were also used to serve as a backup source of hydraulic energy in case of absence of the main hydraulic supply from the surface. The rig operated at 1500 m water depth on the day of accident.

Lower BOP stack consisted of upper blind shear rams, lower casing shear rams, followed by a set of two variable bore rams and one test ram. All ram BOPs were of Cameron TL type, 18 3/4" size, rated for 15000 psi working pressure and equipped with ST locks, except of CSR [11]. Eight 80-gallon hydraulic accumulator bottles were mounted on the lower BOP stack for emergency functions, such as AMF/deadman and autoshear [12]. No acoustic backup control system was installed at the stack.

The main hydraulic supply from the rig had pressure of 5000 psi as it is common for MUX control systems. It was regulated down at the control pods. Accumulators were charged up to 7200 psi. However pressure from these accumulators was also regulated down to 4000 psi [13].

4.1.2 BOP system status after accident took place

After the hydrocarbons have been released to the drilling deck, some rapid well control actions were taken. First response was to reroute the blowout to the MGS via the diverter system. Second action was to close the upper annular preventer. However, the pressure at the drill pipe did not indicate the proper seal, most likely due to already established high flow over it. After that, an attempt was done either to close the VBR or to tighten the AP by regulating its hydraulic supply pressure. This action did temporary seal the well, but at this point, high well flow over the AP cased erosion in sealing element of the preventer and in the drill pipe. Closing the VBR caused the drill pipe pressure to rise, followed by its rapture at the eroded section upstream. The released flammable gas exploded on the rig. The crew attempted to run the emergency disconnect sequence with no luck. The explosion damaged the MUX cables, leaving the rig without control over the BOP [12].

The emergency automatic mode function (AMF) was armed prior to accident. However, later investigation showed that due to low battery voltage and misswired solenoid valves in the control pods, the AMF system could not shut in the well [14]. Later ROV intervention would also discover a leak at the hydraulic control circuit of the SBR. Table 4.1 shows the status of the different BOP components after the rig sank.

Component/function	Status
Upper annular preventer	Closed; Seal eroded due to high flow.
Lower annular preventer	Open
Upper shear blind ram	Open; 0.1 gpm leak at the ST-lock circuit [12].
Lower casing shear ram	Open
Upper variable bore ram	Closed; Seal achieved.
Middle variable bore ram	Open
Lower test ram	Open

Table 4.1 – DWH BOP system status after the rig sank

4.1.3 Emergency operation

After the explosion damaged the BOP control cables, and absence of acoustic control system installed, ROV intervention was the next step in emergency operation. Using the hotstab interface, ROV tried to activate the shear blind ram. No pressure build-up indicated that there was a leak in the system. The leak was found at the ST-lock close circuit (Figure 4.1). The autoshear rod was then cut by ROV in to simulate the LMRP disconnection. This action did not seal the well. The second try was made to activate SBR after the leakage at the ST-lock circuit had been fixed. Pressure build up indicated that the SBR had already been closed by cutting the autoshear rod.

Later attempts were made to close the middle pipe ram and annular preventer using the sea deployed accumulators with no luck. Several issues emerged including hydraulic system leak and incorrect hydraulic plumbing from ROV panel to pipe rams [14].

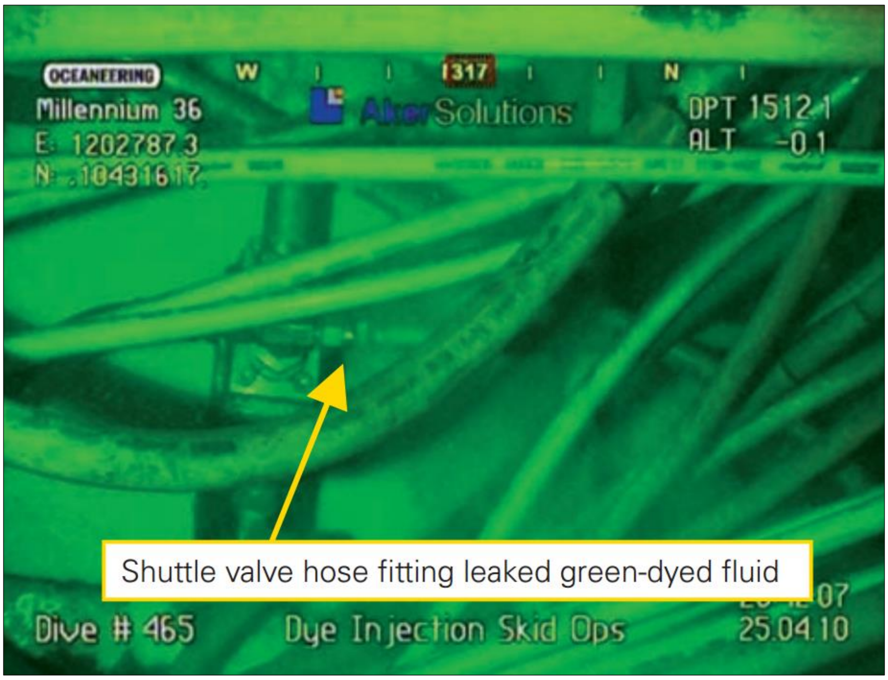

Figure 4.1 – ROV photo of leaking hose fitting at ST-lock hydraulic circuit
Photo: BP, Deepwater Horizon Accident Investigation Report

4.2 Case 2 - Diamond Ocean Concord

Accident at Diamond Ocean Concord drilling rig occurred February 28, 2000 in Gulf of Mexico. A subsea engineer was installing protective caps on the BOP control buttons while the rig was exposed to the well formations, installing the liner. The engineer successfully installed the caps at the drillers control panel. He did not lock out the control panel at the tool pusher's office while he was performing the caps installation and accidently pushed the LMRP unlatch button.

The accidental LMRP unlatch command resulted in the release of the oil-based drilling mud column from the riser making the well underbalanced. Underbalanced well begun to flow. The BOP, located at 762 m depth [15], did not have any secondary control system, nor a ROV intervention panel.

The crew managed to latch the LMRP on to the lower BOP stack after several attempts, before the high velocity well flow has been established. BOP control was gained and the well has been secured [16].

4.2.1 BOP system configuration

The blowout preventer used at the Diamond Ocean Concord rig was comprised of two Shaffer 21 ¼” annular preventers, having working pressure up to 5000 psi and four Cameron 18 ¾” 10000 psi ram preventers [17]. As mentioned above, the BOP was not equipped with ROV intervention panel that would allow the hotstab operation of the ram preventers. The fact that the well was not secured after the LMRP disconnect tells about the absence of the autoshear function or that the function was not armed prior drilling operation.

4.3 Case 3 - Discoverer Enterprise

While tripping out of the hole, the drilling riser parted apart in two places – right above the LMRP and approximately in the middle of the riser column. Discoverer Enterprise rig was conducting drilling operations in May 2003 in the Gulf of Mexico. The water depth at the location was 1844 m. The immediate ROV survey confirmed the parted riser. At this point, drilling rig had no primary control over the BOP. Likely, the automatic mode function (AMF) at the BOP did what it was designed to, closing the shear blind rams and sealing the well [18].

a) **b)**

Figure 4.2 – Photo of parted riser

a) LMRP after the mud release b) Mud plume escaping from the parted riser
Photo: OCS Report – Fate and Effects of a Spill of Synthetic-Based Drilling Fluid at Mississippi Canyon Block 778

4.4 Cases summary

These three cases demonstrate some important things. They show that the problem of loss of primary BOP control exists. The consequences of such loss depend on the reliability of the emergency functions of the BOP system, such as autoshear and Deadman systems and the existence and reliability of the secondary control systems such as acoustic systems etc. They show also that clear emergency procedures should be available in such cases. The personnel preparedness is crucial in such events to gain control over the situation.

5 Emergency operation of BOP

5.1 Definition

Drilling an offshore well in most cases will require the operation of the blowout preventer by the drilling crew. Operation of the BOP during drilling activities is a normal procedure and usually follows a kick in attempt to control a well. The well kick can be triggered mainly during drill pipe tripping, during drilling or well completion activities. Tripping the drill pipe can cause a piston effect (swabbing/surging), reducing the pressure balance in a well. It is also crucial to replace the volume of the tripped drill pipe by the mud, in order to keep the hydrostatic balance in the well. Using too light mud, hitting an unexpected high-pressure zone etc. can also cause a kick. As an example of a well completion activity that can cause a kick, negative integrity test of a well can be mentioned.

If the well control activities fail, kick turns into a blowout. Hydrocarbons then escape the well uncontrolled either subsea, topside or at both locations. This can lead to catastrophic consequences. The blowout, however, can occur not only due to failed well control, but also due to disconnection between the drilling rig and the well e.g. LMRP disconnect (Case 2), riser rapture (Case 3) etc. If the mud column in the riser disappears, the underbalanced well will start to flow.

In order to prevent the blowout and reduce the consequences, different emergency systems and functions were developed. Some of these functions are fully automatic; some have to be activated by the crew. Automatic functions need however to be armed in advance from the surface.

When the well or BOP control are lost, emergency operation of the BOP is then required either by drilling crew or automatics. In case when these actions fail to establish the well control, third party intervention becomes necessary. This work will analyze possible methods to operate the BOP at the last stage of emergency (ref. Figure 5.1).

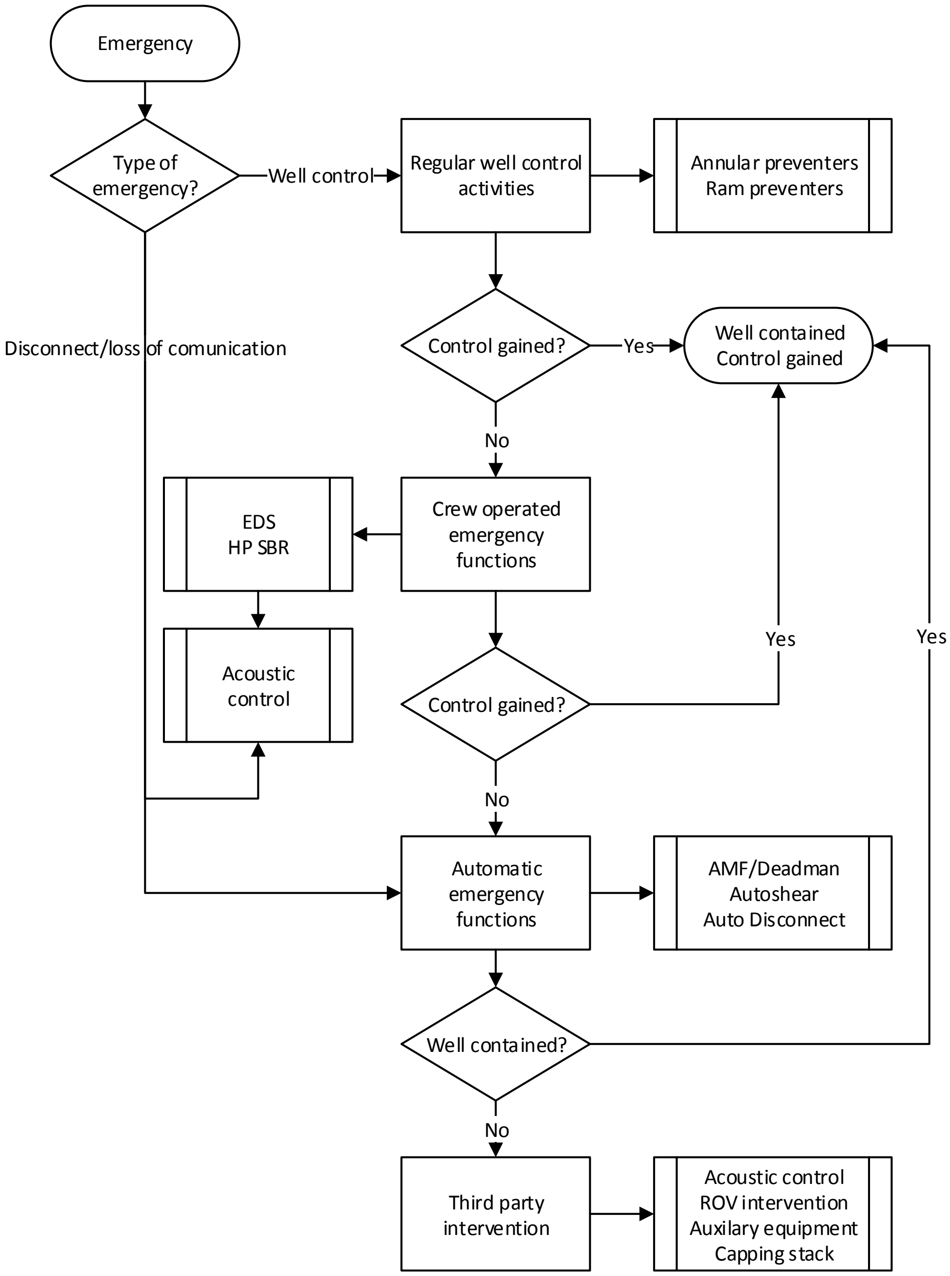

Figure 5.1 – Emergency response flow
Figure: Made by author

5.2 BOP emergency operation methods

When the well cannot be controlled using existing connection between the BOP stack and the host facility due to several reasons, there is a number of alternatives. Three main types of control methods exist today – acoustic, ROV intervention and use of capping device to gain control of the well. Despite the third option is not directly related to controlling the BOP, it is mentioned in this work, due to its common task to get the control over the well.

As stated above, the main task for all methods is to gain control over the well. However, various methods, depending on the situation at site will require different amount of time to execute.

Following seven methods to control the subsea blowout preventer in emergencies will be presented in the next section:

1. Acoustic control method
2. ROV intervention methods
    a. ROV intervention method A – ROV pump
    b. ROV intervention method B – ROV skid
    c. ROV intervention method C – Subsea deployed line
    d. ROV intervention method D – Seabed deployed accumulators
    e. ROV intervention method E – Other means
3. Control method using capping stack

5.2.1 Control method 1 of 3 - Acoustic control

Acoustic control system provides wireless link between a subsea BOP and surface. It is capable to transmit monitor-data from the well such as pressure and temperature, and to control several BOP functions. A conventional ACS (acoustic control system) consists of a command unit connected to a top transceiver with wire and a pair of fully independent bottom transducers connected to a subsea electronic module (SEM), ref Figure 5.2.

An acoustic command unit is a permanently installed panel on a rig connected to a transceiver in the bottom of the rig hull. However, there are also portable command units with transceivers available. Acoustic signals sent from surface are received by the transducers subsea at the stack. SEM receives acoustic signals from the command unit, decodes them and sends electric signals further to the solenoid valves located in the stack-mounted acoustic control pod. Solenoid valves then supply hydraulic pilot pressure to the acoustic SPM valves that open for hydraulic supply for the targeted BOP function.

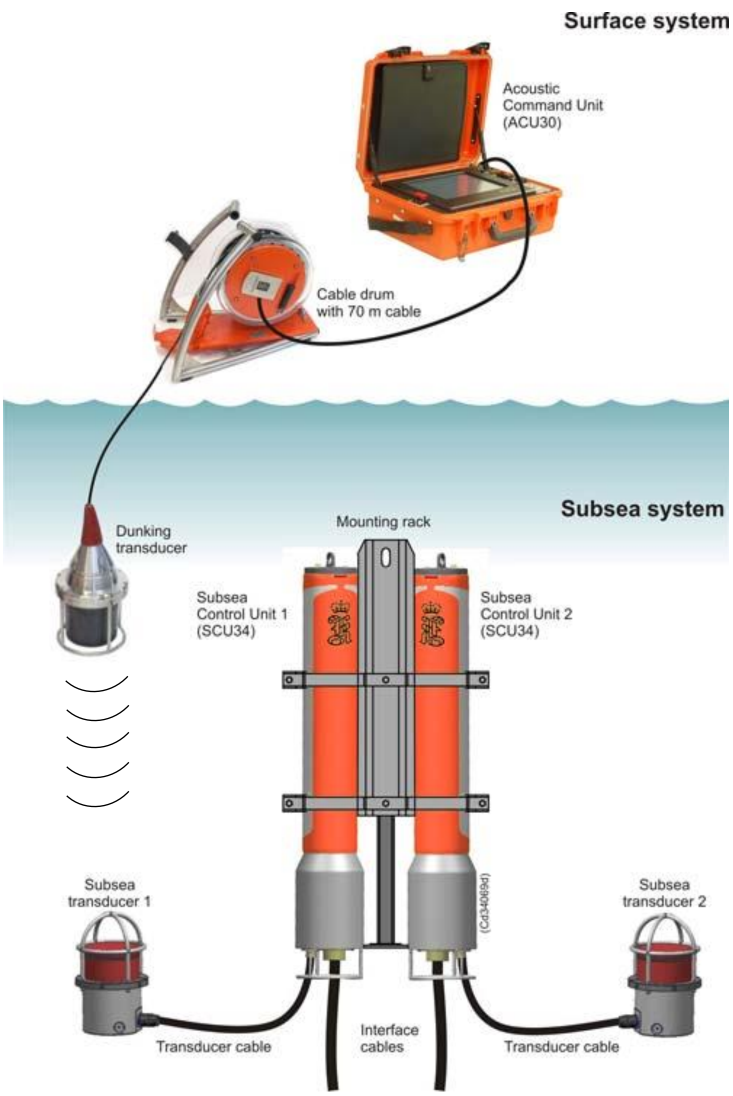

Figure 5.2 – Acoustic control system
Figure: Kongsberg Maritime

For ACS to be considered as an emergency backup system, it has to operate fully independent from the primary control system. To do so, it is often supplied with a battery pack for electronics. Battery level is continuously transmitted to the surface. ACS uses also its dedicated hydraulic accumulator for the pilot signals. It is located inside the acoustic control pod.

For the operation of the BOP functions by ACS, stack mounted accumulators are used. Typically one accumulator is dedicated for the functions triggered by ACS, such as pipe ram operation and LMRP connector functions. Though shared, so-called shear accumulator is used for SBR or CSR functions. Appendix A illustrates a simple schematic of an ACS with SBR-close and LMRP-unlatch functions. A typical number of functions operable via ACS is shown below in the Table 5.1.

	Function	Acoustic control system	Hydraulic power source
LMRP	LMRP connector unlatch	X	Acoustic accumulator
	Upper annular preventer close		
	Lower annular preventer close		
Lower stack	Upper shear ram close	X	Acoustic + shear accumulator
	Lower shear/casing ram close	X	Acoustic + shear accumulator
	Upper pipe ram close	X	Acoustic accumulator
	Middle pipe ram close	X	Acoustic accumulator
	Lower pipe ram close	X	Acoustic accumulator
	Wellhead connector unlatch		
	Arm/Disarm ACS	X	Acoustic pod accumulator
	Arm/Disarm AMF/Deadman		

Table 5.1 – Typical functions operated via acoustic control system

API Specification 16 D 5.8.2.2 states that the required acoustic accumulator functional volume shall not be less than the volume needed to operate all of ACS functions. [9]

In the absence of the primary ability to control the BOP, acoustic is the first emergency system to be activated to attempt gaining control over the BOP. It can be used almost immediately after the emergency initiation. Even if the host facility is unavailable, ACS commands can be sent from the portable command unit, located at the helicopter, supply vessel or a lifeboat. A dunking transceiver is then has to be submerged into the water to send the acoustic signals. Most recent ACS can operate in water depths up to 4000 meters. However, a special technical training is required to adjust the acoustic system for different water depths to optimize the link between transceivers and hydrophones. Depending on the system and subsea transducers configuration, noise from the blowing well mud plumes could affect the capability of acoustic system to communicate. Large debris pieces could also be a hindrance for the acoustic signals to reach the targeted transducers installed on the BOP stack.

5.2.2 Control method 2 of 3 - ROV intervention

A presence of one observation (Class I) and one work-class (Class III) ROV onboard the drilling vessel is a good practice offshore. Observation ROV is usually used to monitor subsea activities and for general observation and checking. Observation ROV cannot perform physical actions in comparison to work-class ROV. Work-class ROV, in its place, is used to install and retrieve gaskets between wellhead and lower BOP stack and between lower BOP stack and LMRP. It is also used for other tasks when needed.

Second alternative to the acoustic control method is then ROV intervention. ROV intervention is a very common task nowadays. The possibilities of an ROV in BOP operation is much wider and flexible compared to acoustic control when it comes to hydraulic power source. Among emergency functions, Table 5.2 shows the most typical that are available for ROV intervention.

	Function	ROV intervention	Hydraulic power source
LMRP	LMRP connector unlatch	X	ROV Hotstab
	Upper annular preventer close		
	Lower annular preventer close		
	LMRP accumulator charge	X	ROV Hotstab
Lower stack	Upper shear ram close	X	ROV Hotstab/shear accumulator[5]
	Lower shear/casing ram close	X	ROV Hotstab
	Upper pipe ram close	X	ROV Hotstab
	Middle pipe ram close	X	ROV Hotstab
	Lower pipe ram close	X	ROV Hotstab
	Wellhead connector unlatch	X	ROV Hotstab
	Arm/Disarm ACS		
	Arm/Disarm AMF/Deadman	X	ROV Hotstab
	Acoustic accumulator charge		
	Shear accumulator charge	X	ROV Hotstab

Table 5.2 – Typical emergency functions available for ROV

Since most of the BOP functions operated by ROV intervention are done using the hotstab, the source of hydraulic power is only the matter of equipment connected to the hotstab. However, there are several limitations for using the ROV. It takes time to deploy a ROV, and time taken depends on the presence of the ROV onboard or presence of a supply vessel nearby with a proper ROV onboard. Deploy time depends also on the water depth the ROV will be lowered to. Availability of auxiliary equipment for ROV intervention is also a factor that can increase the time required to deploy a ROV. A major issue draining time can be a presence of debris around the BOP, which prevents the ROV access. The debris has to be cleared in order to give a minimum access for the ROV to the BOP stack.

[5] Closing of upper shear ram by ROV intervention can be done either by hotstab operation or by triggering one of the primary emergency functions, e.g. autoshear, AMF.

Figure 5.3 – Single port API 17H hotstab and receptacle
Photo: SECC Oil & Gas

Weather and environmental conditions such as high current velocities and rough sea states can affect the possibility of ROV intervention. The typical ROV launch and recovery systems (LARS) can perform in up to sea state five[6]. Deployment of a ROV in to the rough sea produces the risk of damaging the equipment, when lowering it through the splash zone. However there are solutions for heavy weather deployment that are able to launch and recover ROVs in sea sate six environment[7] by using the guide -wires or -rails and optionally protective structure around the ROV and tether management system (TMS).

When it comes to operation of specific BOP functions through a hotstab, ROV will have to be able to supply enough flow and pressure by its own means or using some sort of auxiliary equipment. A total response time is very important in cases with a blowing well. A flowing well has to be contained as fast as possible to avoid the high well flow damaging the BOP. Closing the rams or annular preventers has to be done very rapidly to avoid damage to the seals by the well flow. The minimum function response times are specified by several standards and are shown in Table 5.3.

[6] Sea states characterize the wind sea using the codes. Here, sea state 5 defines the significant wave height interval of 2.5 to 4 m 19. Wikipedia. *Sea state*. [cited 2015 28.04]; Available from: http://en.wikipedia.org/wiki/Sea_state..
[7] Sea state five – significant wave heights of 4 to 6 m.

Referencing document	Response time
API Std. 53 (7.3.10.4) [20]	Annular: less than 60 s. Rams: less than 45 s. LMRP unlatch: less than 45 s. C/K valve: Ram times
API Spec 16D (5.2.1) [9]	Annular: less than 60 s. Rams: less than 45 s. LMRP unlatch: less than 45 s. C/K valve: Ram times
NORSOK D-001 (6.42.1) [5]	Refers to API Spec 16D

Table 5.3 – Response time requirements

18 ¾” 15K Shaffer BOP using the discrete hydraulic control system will be used to illustrate typical volumes and pressures required to operate different functions on the BOP stack, ref. Table 5.4.

	Function	Pressure [PSI]	Volume [gallon]
LMRP	LMRP connector unlatch	1500	5.16
	Upper annular preventer close	1500	66.16
	Lower annular preventer close	1500	66.16
	LMRP accumulator charge	5000	53.37 (usable volume: 38.12)
Lower stack	Upper shear ram close	1500	33.00
	Upper shear ram HP close	3000	33.00
	Lower shear/casing ram close	1500	37.70
	Lower shear/casing ram HP close	3000	37.70
	Upper pipe ram close	1500	16.80
	Middle pipe ram close	1500	16.80
	Lower pipe ram close	1500	16.80
	Wellhead connector unlatch	1500	5.16
	Acoustic accumulator charge	5000	67.25 (usable volume: 48.03)
	Shear accumulator charge	5000	77.87 (usable volume: 77.87)

Table 5.4 – Shaffer BOP pressures and volumes

The different ROV intervention methods are discussed further.

5.2.2.1 ROV intervention method A - ROV Pump

A most common work class ROVs used on drilling and support vessels are equipped with pumps capable to deliver 210 bar at around 50 l/min. However, some ROVs are equipped with so-called API Std 53 systems, that are equipped with more powerful hydraulic power units. These are capable to supply higher pressures at higher flows. Oceaneering has some types of these ROVs. Ref. Table 5.5.

Manufacturer	Model name	Max pump pressure [bar]	Max pump flow rate [l/min]	Effect [kW]
Kystdesign	Supporter	210	75	26.1
	Installer	210	75	26.1
IKM Subsea	Sub Atlantic Comanche	210	28	13.4
	Merlin WR200	315	49-80	18-30
		250	20-49	8-18
Oceaneering	Millennium Ultra[8]	API Std 53		
	Millennium Plus	325	151.4	82
	Magnum Plus	400	94.6	63
	Maxximum	400	151.5	101
		306	197	101
Schilling Robotics	HD ROV	207	70	24.1
	UHD III ROV[9]	345	189	109
		172	284	

Table 5.5 – Typical ROV HPU capabilities[10]

Using the ROV HPU to operate BOP functions in emergencies will lead to two main problems. The first problem is the power of the HPU; the second is the available hydraulic fluid at the ROV reservoir.

Pressures and flows supplied by the ROV pump system depend on the HPU power. Simplified, we can say that these parameters follow equation (5.1).

$$E = P * \dot{V} \tag{5.1}$$

Where E is power of the HPU; P is pressure delivered; $\dot{V}$ is flow delivered.

Capabilities to operate the Shaffer BOP functions by the ROV types outlined in Table 5.5 are showed in Table 5.6 and Table 5.7.

[8] Manufacturer datasheet specifies that the ROV type fulfill the API Standard 53 requirements.
[9] Schilling UHD III is equipped with 100+ gallon fluid reservoir onboard
[10] The data was obtained from the manufacturers web sites.

Manufacturer	Model name	LMRP unlatch	LMRP accumulator charge
Kystdesign	Supporter	X	
	Installer	X	
IKM Subsea	Sub Atlantic Comanche	X	
	Merlin WR200	X	
Oceaneering	Millennium Ultra	X	X
	Millennium Plus	X	
	Magnum Plus	X	X
	Maxximum	X	X
Schilling Robotics	HD ROV	X	
	UHD III ROV	X	X

Table 5.6 – Capability to operate LMRP functions by different ROV types

Manufacturer	Model name	SBR close	SBR HP close	CSR close	CSR HP close	U/M/L pipe ram close	WH connector unlatch	Shear accumulator charge[11]
Kystdesign	Supporter						X	
	Installer						X	
IKM Subsea	Sub Atlantic Comanche						X	
	Merlin WR200						X	
Oceaneering	Millennium Ultra	X	X	X	X	X	X	X
	Millennium Plus					X	X	
	Magnum Plus					X	X	X
	Maxximum	X	X	X	X	X	X	X
Schilling Robotics	HD ROV						X	
	UHD III ROV	X	X	X	X	X	X	X

Table 5.7 – Capability to operate lower stack functions by different ROV types

Table 5.6 and Table 5.7 show clearly that only chosen ROV types are able to operate the most crucial BOP emergency functions such as blind/casing shear rams and their high-pressure function directly. The inability to do so is often due to either low flow rate or pressure supplied

[11] Charge of BOP accumulators assume enough hydraulic fluid volume onboard ROV or ability to pump seawater directly.

by the ROV. Additional factors such as system pressure drop, possible leakages will play its role in the ability to operate the desired BOP functions.

Despite the power of the HPU on the ROV could be enough to operate the BOP functions, the need of large volumes of hydraulic fluid to operate these functions faces the second problem discussed above – fluid volume available at the ROV. The BOP hydraulic systems are usually open-circuit systems, meaning that the operational fluid is vented to the environment after the function is executed. That means that the ROV pumping system will need the whole fluid volume required by the BOP function available onboard. The normal compensator (reservoir) volume installed on work-class ROVs is between 16 and 20 liter. In worse case, seawater can be pumped directly into the BOP control system instead of hydraulic fluid. This is not the optimal solution due to corrosive properties of the seawater and absence of lubrication. Schilling ROVs have this function.

These two factors make it nearly impossible to use ROV pump system to emergency operate BOP functions. Suitable ROVs are not always available onboard the drilling vessel or support vessels in the area, and it will take time to mobilize one from the shore. Perhaps price for the ROVs capable to operate emergency BOP functions is a step higher than normal work-class ROVs.

5.2.2.2 ROV intervention method B - ROV Skid

To boost up ROV capabilities, many different add-ons called skids have been developed. A skid is typically a construction, which is fixed at the underside of the ROV and matches its footprint (Figure 5.4).

Figure 5.4 – BOP intervention skid
Photo: Oceaneering

Skids are loaded with auxiliary equipment that ROV can use under its mission, powering it with the ROV pump or/and electricity system. Skids used for BOP intervention are usually comprised of a hydraulic fluid bank and a set of high pressure/high flow pumps that are able to deliver required power to the BOP. Skid hydraulics make it possible to convert the ROV HPU output to have either higher flow or pressure. The total amount of output energy is preserved, minus the effect loss after conversion, unless skids get additional power via electric system of the ROV. Typical output possibilities are around 345 bar (5000 psi) pressure and 300 l/min (67 gpm) flow rate.

As already mentioned, skids usually carry hydraulic storage with them. Typical volume of the fluid reservoir, if placed in the skid, is around 400 liter (106 gallon).

ROV skid is a low cost boost for ROVs functionality. Skids are usually easy installable and ready to use after only few connections up to the host system of the vehicle. The size and weight of the skid make it flexible addition that could be used in emergencies.

5.2.2.3 ROV intervention method C - Subsea deployed line

An alternative to powerful ROV, carrying the skid with the hydraulic fluid is the sea-deployed hydraulic line. The line can be a coiled tubing or a reinforced hose. Hydraulic fluid is then supplied from the vessel on the surface through this line subsea having high enough flow and pressure. A ROV can then, by means of a jumper hose, connect the subsea-deployed line to the desired hotstab located at the BOP intervention panel. This method eliminates the power requirements of the ROV.

Time to deploy the subsea line will vary and depend on the availability of the coiled tubing reel equipment, hydraulic fluid and pumping equipment onboard of nearby vessels or onshore.

5.2.2.4 ROV intervention method D - Seabed deployed accumulators

Figure 5.5 – Oceaneering Subsea Accumulator System
Photo: Oceaneering

Another method to secure a successful BOP intervention is to deploy a reserve accumulator bank to the seabed, which can then provide hydraulic power to function the BOP, see Figure 5.5. The accumulator bank needs to be gas pre-charged on the surface prior to deploying it. Nitrogen is usually used for this purpose. Gas charging pressure depends on the water depth, where the accumulators will be used.

Accumulators can be charged with hydraulic fluid at the surface, however due to seawater pressure gradient, the usable fluid volume is reduced dramatically, increasing size and weight of the accumulator bank. That is why, using smaller accumulator systems and charging them with hydraulic fluid subsea is often done. See Appendix C – Example of the water depth effect on the usable accumulator fluid volumefor a simple example on this matter.

The usage of this method depends however on availability of the ROV. Special procedures for gas charging are required, taking into account the factors such as changes in gas density due to temperature difference and the cooling effect caused by the rapid discharge.

5.2.2.5 ROV intervention method E - Other means

This method is based on use of residual power stored in the BOP accumulators. There is a possibility that not all of the accumulator fluid volume was used during the first stages of attempting to gain control over the well, and there is pressurized control fluid still available. This power can then theoretically be used for operation of BOP functions. Depending of the available fluid volume and pressure in the accumulators and the ROV intervention panel capabilities, different functions can be triggered.

BOP actuators can be run by operating the corresponding valves on the ROV intervention panel, if such are available, see Figure 5.6. An attempt to trigger the autoshear function can be done by simulating the LMRP disconnect, cutting the so-called “autoshear” rod. However, one have first to ensure that the emergency function is armed. Arming the Deadman system can allow the residual hydraulic power to function the shear blind rams in the BOP.

Figure 5.6 – ROV intervention panel
Figure: Made by author

In a case where the ROV is not capable to deliver the minimal flow rate to operate the BOP safely, but is capable of delivering the required pressure, an option is available. However, this is possible only if the accumulator bank can be isolated from the main control system. Charging the accumulators does not require high flow rates and can be done by the ROV having low flow rate. The charged accumulators can then supply the required flow rate and pressure to the targeted functions.

5.2.3 Control method 3 of 3 - Capping stack

Capping stack is a device very similar to a BOP. It is used to contain the blowing well. It can either seal it or direct the hydrocarbons to a floating storage vessel.

The capping stack consists of a wellhead connector in the bottom that is used to connect and obtain a seal between either a wellhead, a top of the BOP or LMRP. Two or more ram type BOP valves are placed on to the connector with a mandrel on top of them. Choke and kill outlets are connected below the BOP valves. A typical configuration consists of two kill lines having two gate valves each, and two choke lines with gate valves and retrievable chokes. All the functions are operated through the ROV intervention panel hydraulically or mechanically using the standard torque tool. Operational fluid is supplied by the seabed deployed accumulator bank.

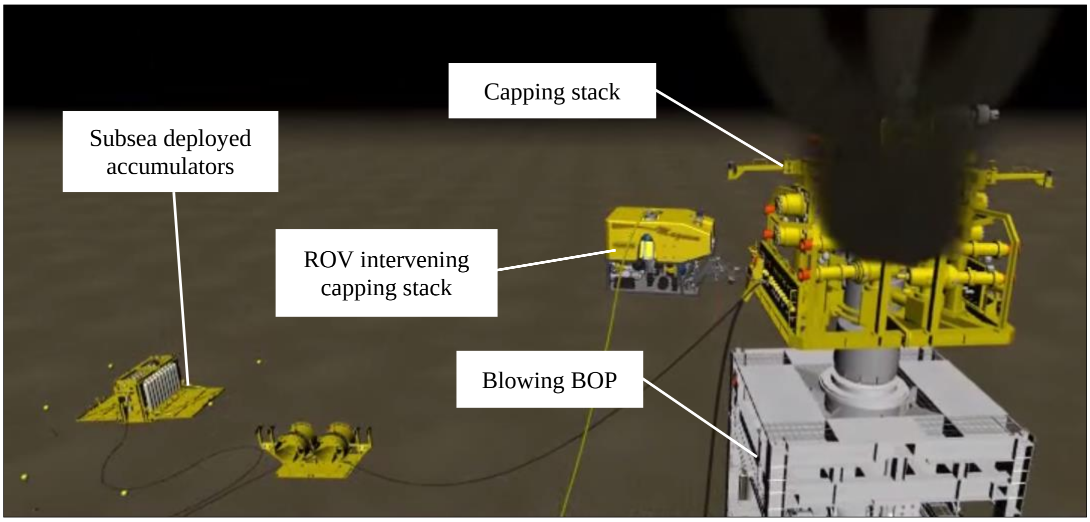

Figure 5.7 – ROV intervention on the capping stack
Image: Subsea Well Response Project

In the event of emergency, the capping equipment is transported offshore to the site. The weight of the stack can be 50-100 MT, implying the transportation difficulties. When on site, using the special running tool allowing the well flow to penetrate, the capping stack is lowered over the blowing BOP or wellhead. Choke and kill lines are then opened and the blind rams are closed, following by closing of the kill lines and “soft-shutting” the well using the choke lines. Chemical injection, pressure and temperature transition are often features that are included in the capping equipment. Figure 5.7 illustrates the ROV intervention of the capping stack installed on a BOP. The stack is connected to the seabed deployed accumulator bank using flying lead.

Special studies and analyses are required prior to deploying the capping stack to avoid hydrate forming inside the stack. ROV intervention has to examine the BOP for the possibilities to connect the capping stack and not least for possible debris that could prevent the deployment.

5.3 Methods summary

Several BOP control methods were discussed so far. All methods have their advantages and disadvantages in form of different factors. Table 5.8, outlines a comparison of operation methods discussed in this work by using following factors:

Availability and response time – availability of the equipment at site or in the world, and its response time in form of time the emergency occurred until the well is contained.

Weather dependency – if the deploying of emergency equipment requires the special weather conditions.

Capability – capability of the method to operate the crucial functions leading to well securing.

Standalone system – independence of the system / method from other auxiliary equipment.

Affected by the well flow – operability of the method under the presence of the oil/gas plume.

Cost efficiency – indicator of the total cost for deploying the emergency equipment against the methods response time and method capability.

Issue	Method 1 Acoustic control	Method 2A ROV intervention ROV pump	Method 2B ROV intervention ROV skid	Method 2C ROV intervention Deployed line	Method 2D ROV intervention Deployed accumulators	Method 2E ROV intervention Residual BOP power	Method 3 Capping stack
Availability and response time	Very short response times, however, usually not available on the drilling rigs. Obligatory in North sea.	Good response times. Available on most drilling vessels and installations.	Good response times. Time skid mounting and function test required. Usually not available onboard – need to be shipped. Available onshore.	Intermediate response times. Special equipment is required. Not available onboard. Easy to acquire onshore.	Long response times due to charging requirement and transportation. Available onshore.	Good to intermediate response times. Depends on residual hydraulic power in the accumulators.	Long response times. Available only few places in the world.
Weather dependent	No	Yes. Requires calm sea. Normal operating sea is Hs < 4 m.					Yes due to heavy lifting and deploying.
Emergency operation capability	Yes	Generally not capable. Few ROV types available that are capable to operate the BOP directly.	Yes, if ROV is able to supply required power for the skid, either hydraulically or electrically.	Yes	Yes	Unknown. Depends on remained pressure and volume in stack accumulators. Yes, if charging the accumulators by ROV intervention.	Yes
Standalone system	No, uses the control pods on MUX systems. Relies on shared accumulator. Yes, if supplied with dedicated accumulator bank.	Yes	No, depends on ROV power.	No depends on ROV intervention.		No, relies on residual power in the stack accumulators and their operability.	Yes
Affected by the well flow	Yes, can be affected by the flow noise.	Yes, can be affected. Requires special equipment for navigating in low vision environment.					Yes, requires special assessment to avoid hydrate formation.
Cost efficiency	Very high	High	Middle	Low	Low	High	Very low

Table 5.8 – BOP emergency operation methods comparison

6 Discussion

When an emergency occurs at offshore drilling facility, where the primary control over the BOP is lost, minutes count. The immediate decision-making and response are crucial. The preparedness of the drilling companies varies a lot. It depends often on the location they operate, due to differences in authority's demands. This work gave an overview over seven different methods to gain control over a BOP in such cases. As mentioned above, the main issue is the absence of the primary control over the BOP that can be in form of malfunction of the control system, unintended disconnect of the facility or a total disaster like in Deepwater Horizon accident. Each of these methods is unique in its way and suits best for each individual case. However, some of them could be a "good practice" to have in disposition under drilling operations.

6.1 Acoustic systems

One of those is acoustic control system. The major weaknesses with this system are unreliable communication in presence of noise subsea and possible inability to communicate through obstacles such as debris. Most of acoustic control panels nowadays provide the status of the system in form of battery voltage for subsea pods, pressure level and function read-backs, which makes it easy to decide if the system is usable at a moment of emergency. The operation of acoustic system is weather independent, comparing to other methods that require conditional weather to be deployed. The response times of the acoustic systems are incomparable short.

If the system development achieves high enough reliability, it should be obligatory to have installed on every BOP and drilling vessel or installation.

6.2 ROV interventions

ROV intervention is necessary in all the other methods either for operating the BOP or as a support for other equipment. Successful ROV intervention relies on an acceptable weather conditions for deploying the vessel in the first place. Another challenge is the presence of strong underwater current that could affect the usefulness of ROVs having weak thruster power. Low visibility conditions due to mud or oil plume makes it nearly impossible to operate without special equipment. Ultrasound sonars solves the problem of low visibility. Sending the sound waves in front of the ROV and receiving the reflected waves from the obstacles creates a two dimensional image based on the wave arriving time delay, see Figure 6.1.

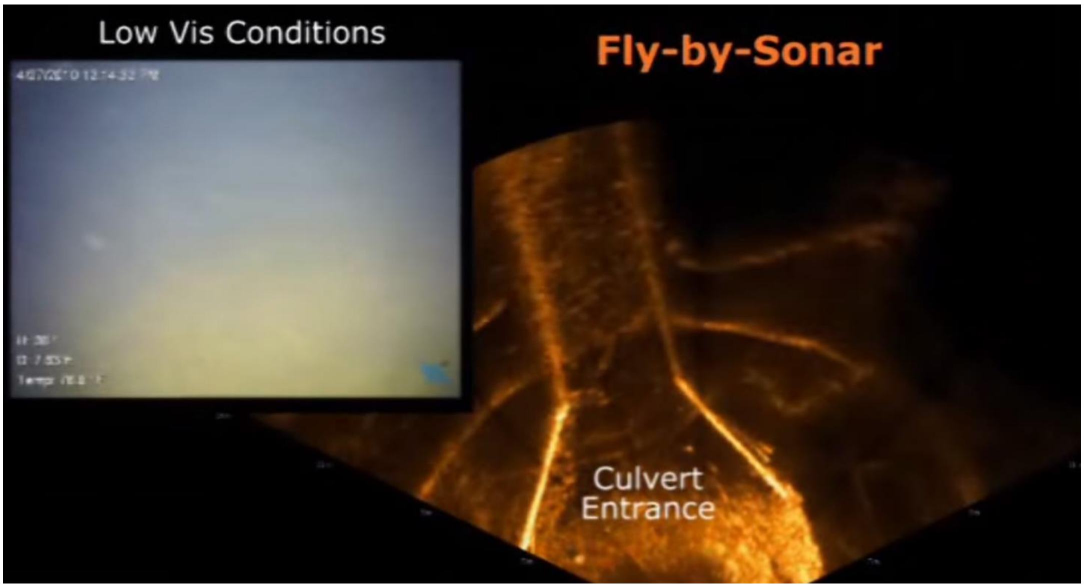

Figure 6.1 – Sonar versus camera in low visibility condition
Photo: Youtube video frame. URL: www.youtube.com/watch?v=CULhKenlqOs

6.2.1 ROV pump system

As it can be seen from the Table 5.6 and Table 5.7, only several ROV types are capable of providing enough hydraulic power to operate the BOP rams. However, the ROV alone can be used in first place for inspection and triggering the BOP functions, which do not require high flow rates, and pressures, e.g. LMRP disconnect.

ROV alone is used to perform the subsea operations allowing the other equipment to do its job. Connecting the jumper hoses, operating valves, assisting in debris clearance[12] and general observation are the main purpose of ROV intervention.

6.2.2 ROV assisted emergency equipment

The ROV skid solution is only applicable for the ROV types that have powerful enough HPU to achieve the full effect of these skids. The largest advantage of these skids is their fluid storage capacity that can be used for charging accumulators on either the BOP stack or the sea-deployed accumulator banks. Equipment such as ROV skids, accumulator banks and subsea deployed “hotline” uses the deck space and provides additional weight for the vessels bearing it. Storing this equipment on the drilling vessel or installations is not useful in cases where the facility has to be evacuated and abandoned. However, it should be available onshore in strategic locations

[12] Debris clearance will require the special tools for parting the debris. Oceaneering provide most of tools needed in their Subsea Emergency Response Toolbox.

to make the emergency response fast. The emergency response equipment should be stored in packages containing several different equipment types available at same location. The choice of the equipment package should be made and prioritized according to the needs at the accident site. E.g., package for debris clearing, package for subsea deployed accumulators etc.

6.3 Capping stack method

Capping stack can be used as an alternative or as an addition to the emergency response method. It does not operate the BOP directly, but extending the current one, with operable part. Due to its large dimensions and weight the decision of using the capping stack is difficult. Despite the involvement of heavy transport, several support and ROV vessels, the use of capping stack is perhaps the most reliable method. Currently capping stack packages are contingency stored in strategic places all around the world.

6.4 Discussion summary

The next table shows evaluation of the methods discussed in this work.

Method	**Evaluation**
1. Acoustic control	ACS is the only wireless control method. Its operation is independent of other control elements. However, the BOP operation via ACS relies on the stack mounted accumulator power. Further development of the technology with focus on the communication reliability is required.
2a. ROV pump	Special ROV types required to operate a blowing BOP safely without damaging the seals. Regular work class ROV will most likely fail in operating the BOP functions directly using its own hydraulic pump system. Failed attempts can also damage the BOP sealing elements.
2b. ROV skid	Skids have a large potential. If supplied with enough power, these can located onboard drilling vessels and ROV support vessels in the area, on a regular basis.
2c. Sea-deployed line	This method can probably replace the seabed-deployed accumulators in shallow areas. Deep waters will create large loads on the line due to its own weight. Weather will influence the usability of this method.
2d. Seabed deployed accumulators	Time-consuming method. Seabed-deployed accumulators will probably be useful in cases when the stack-mounted accumulators are discharged. Accumulator discharge should not have occurred due to BOP operation, but due to a leak in the system or other reasons. This means that BOP closing devices were not operated prior to intervention using the seabed-deployed accumulators.
2e. Residual BOP power	An attempt to control the BOP using its own power shall be made. However, one must ensure that there is enough accumulator pressure / volume to close the BOP device safely. This method can be safely used in attempts to unlatch the LMRP/wellhead or to arm different BOP emergency functions (AMF, Autoshear).
3. Capping stack	The most time consuming and expensive method. This is probably the last method to be used, after all other methods failed. Capping stack allows for further work on the well after its installation – rerouting the well flow to a floating storage vessel, kill the well using the kill lines at the stack.

Table 6.1 – Emergency operation methods summary

6.5 Further recommendations

6.5.1 BOP status indicators

BOPs could be equipped with the visual indicators or logging devices for valves status (rams, ram locks, choke and kill valves etc.) and pressure/volume status of the accumulators. This information acquired by the ROV inspection could be useful in decision-making and choice of the control method.

6.5.2 Accumulator isolation valves

ROV intervention panels can be fitted with an accumulator isolation valve. The valve will isolate the accumulators from the control system, so that they can be charged using the low flow rated ROV pumps. After the charging is complete, high flow capacity of the accumulators can then be used to trigger the BOP functions such as shear blind rams.

6.5.3 Divide accumulator banks in groups

Dividing accumulator batteries in groups will reduce the risk of whole accumulator bank discharge in case of a leakage. This can be done by use of sequence and check valves. The accumulators will then discharge sequentially one by one. When the first group pressure falls below the set value, the flow from the next group of accumulators will then be opened. It will however require separate lines from each accumulator group to the targeted function of the equipment, ref. Appendix D.

6.5.4 Standard acoustic control protocol

The command units can be provided to most of the vessels, supporting drilling facilities. This will allow each individual BOP to be controlled from not only the host facility but also the surrounding vessels in case of emergency. Providing address and passphrase to the subsea control units upon the engaging the control can be a security measure to employ. Implementation of unified acoustic control protocol will require some level of standardization. This measure will reduce the total amount of accidents.

6.6 Conclusion

This work gave an insight into the problems and challenges associated with the emergency operation of subsea blowout preventers. Among the chosen methods, this work looked at five of seven methods, which require remote operated vehicle intervention to operate. ROV skids require ROV power. Subsea deployed accumulators and lines together with capping stack need to be connected to the ROVs and to be operated by them. ROV will most likely fail to operate the BOP on its own. Usage of auxiliary equipment such as intervention skids or seabed-deployed accumulators require time and good weather conditions. Acoustic control is the only wireless method that allows very fast response. However, acoustic control systems have their drawbacks in form of communication reliability. This leads to the fact that remote and wireless BOP operation technologies, such as acoustic needs to be developed to avoid the ROV intervention.

To strengthen the other methods, ROV power capabilities should be extended, allowing to provide more power to the equipment, to lift heavier parts, to move in rougher seas and navigate in low to zero visibility conditions.

The key in emergency preparedness is to have clear plans and procedures for main types of scenarios, reliable and tested contingency equipment and personnel training in such scenarios.

Deepwater Horizon accident was the triggering event on the way to achieve the wanted level of safety and reliability of the BOP systems and their secondary and alternative ways to operate them.

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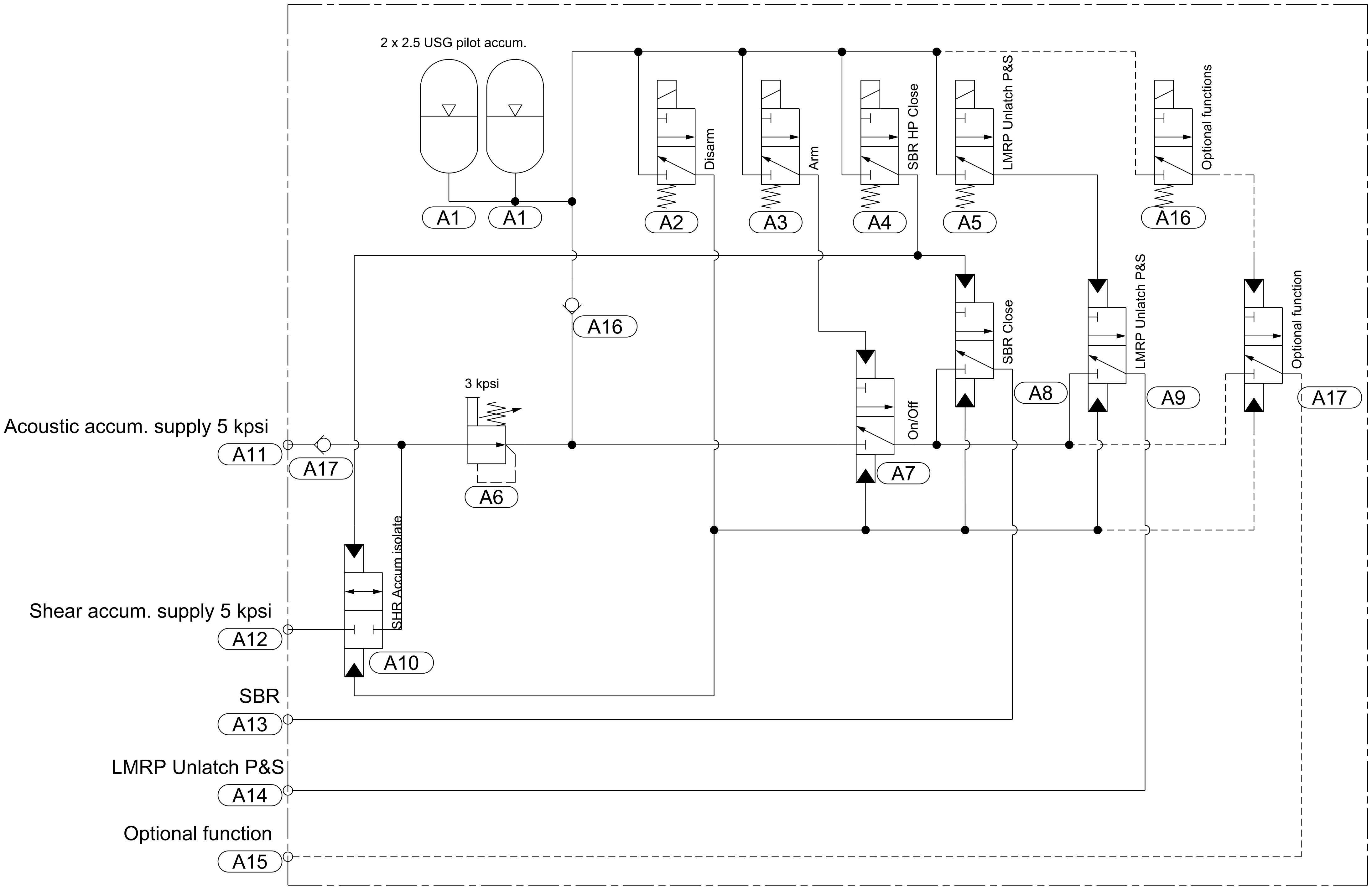
Appendix A - Simple hydraulic schematic of an ACS

Simple hydraulic schematic of an ACS comprising SBR close and LMRP unlatch functions.

Pos.	Qty.	Type	Description	Manufacturer	Remark
A1	2	Piston accumulator	Accumulator supply for pilot hydraulic circuit		
A2	1	Solenoid valve	Disarm ACS		
A3	1	Solenoid valve	Arm ACS		
A4	1	Solenoid valve	SBR Close		
A5	1	Solenoid valve	LMRP Unlatch (Primary & Secondary)		
A6	1	Pressure regulating valve	6000 psi -> 3000 psi		
A7	1	SPM valve	Arm/Disarm		
A8	1	SPM valve	SBR Close		
A9	1	SPM valve	LMRP Unlatch (Primary & Secondary)		
A10	1	SPM valve	Shear accumulator supply isolation		
A11	1	Hydraulic connection	Dedicated acoustic accumulator supply		
A12	1	Hydraulic connection	Shear accumulator supply		
A13	1	Hydraulic connection	SBR activate		
A14	1	Hydraulic connection	LMRP unlatch		
A15	1	Hydraulic connection	Optional function		
A16	1	Solenoid valve	Optional function		
A16	1	Check valve	Check valve		
A17	1	SPM valve	Optional function		
A17	1	Check valve	Check valve		



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Appendix B – Power required to run BOP functions

Power required by the functions of the Shaffer BOP used as an example in the thesis.

Power required to run BOP functions
By Kiryl Kozel

23/04/2015

LMRP Unlatch

Required pressure: $P := 1500\ psi$

Required volume: $v := 5.16\ gal$

Maximum response time: $t := 45\ s$

Required flow: $V := \frac{v}{t} = 6.88\ gpm$

Required power: $E := P \cdot V = 4.489\ kW$

Upper/Lower Annular close

Required pressure: $P := 1500\ psi$

Required volume: $v := 66.16\ gal$

Maximum response time: $t := 60\ s$

Required flow: $V := \frac{v}{t} = 66.16\ gpm$

Required power: $E := P \cdot V = 43.169\ kW$

Upper Shear Ram close

Required pressure: $P := 1500\ psi$

Required volume: $v := 33\ gal$

Maximum response time: $t := 45\ s$

Required flow: $V := \frac{v}{t} = 44\ gpm$

Required power: $E := P \cdot V = 28.709\ kW$

Upper Shear Ram HP close

Required pressure: $P := 3000\ psi$

Required volume: $v := 33\ gal = 124.919\ L$

Maximum response time: $t := 45\ s$

Required flow: $V := \frac{v}{t} = 44\ gpm$

Required power: $E := P \cdot V = 57.419\ kW$

Lower Shear/Casing Ram close

Required pressure: $P := 1500\ psi$

Required volume: $v := 37.7\ gal$

Maximum response time: $t := 45\ s$

Required flow: $V := \frac{v}{t} = 50.267\ gpm$

Required power: $E := P \cdot V = 32.798\ kW$

Lower Shear/Casing Ram HP close

Required pressure: $P := 3000\ psi$

Required volume: $v := 37.7\ gal$

Maximum response time: $t := 45\ s$

Required flow: $V := \frac{v}{t} = 50.267\ gpm$

Required power: $E := P \cdot V = 65.597\ kW$

Upper/Middle/Lower Pipe Ram close

Required pressure: $P := 1500\ psi$

Required volume: $v := 16.8\ gal$

Maximum response time: $t := 45\ s$

Required flow: $V := \frac{v}{t} = 22.4\ gpm$

Required power: $E := P \cdot V = 14.616\ kW$

Wellehad connector unlatch

Required pressure: $P := 1500\ psi$

Required volume: $v := 5.16\ gal$

Maximum response time: $t := 45\ s$

Required flow: $V := \frac{v}{t} = 6.88\ gpm$

Required power: $E := P \cdot V = 4.489\ kW$

LMRP accumulator charge

Required pressure: $P := 5000\ psi$

Required volume: $v := 53.37\ gal$

Accoustic accumulator charge

Required pressure: $P := 5000\ psi$

Required volume: $v := 67.25\ gal$

Shear accumulator charge

Required pressure: $P := 5000\ psi$

Required volume: $v := 77.87\ gal$

Appendix C – Example of the water depth effect on the usable accumulator fluid volume

Example showing how water depth affect the usable accumulator hydraulic fluid volume if charged subsea compared to surface.

Accumulator usable volume comparison calculation
By Kiryl Kozel

24/04/2015

Conditions:
0 - Precharge
1 - Charged
2 - MOP (Pressure limited)
3 - Total discharge (Volume limited)

Enviroment data:

Water density: $\rho_w := 8.54 \frac{lb}{gal}$

Water depth: $d := (4 \cdot 10^3)\ ft$

Hydrostatic head pressure: $P_h := d \cdot g \cdot \rho_w = (1.77 \cdot 10^3)\ psi$

Accumulator and functions data:

Accumulator bottle pressure rating: $P_{max} := (7 \cdot 10^3)\ psi$

Accumulator bottle volume: $V_0 := 15\ gal$

Pressure required by the function: $P_f := (3 \cdot 10^3)\ psi$

Accumulator charge calculation:

Gas precharge pressure at surface: $P_{ca} := (3 \cdot 10^3)\ psi$

Gas precharge pressure subsea: $P_{cb} := (4.755 \cdot 10^3)\ psi$

Gas pressure subsea for surface charged accumulator: $P_{0a} := P_{max} - P_h = (5.23 \cdot 10^3)\ psi$

Gas pressure subsea for subsea charged accumulator: $P_{0b} := P_{cb} - P_h = (2.98 \cdot 10^3)\ psi$

Gas pressure subsea charged with hydraulic fluid: $P_1 := P_{max}$

Minimum operating gas pressure subsea charged with hydraulic fluid: $P_2 := P_f$

Gas volume subsea charged with hydraulic fluid for surface charged accumulator:

$$V_{1a} := \frac{P_{ca} \cdot V_0}{P_1} = 6.43\ gal$$

Gas volume subsea charged with hydraulic fluid for subsea charged accumulator:

$$V_{1b} := \frac{P_{0b} \cdot V_0}{P_1} = 6.39\ gal$$

Gas volume at minimum operational pressure for surface charged accumulator:

$$V_{2a} := \frac{P_{0a} \cdot V_{1a}}{P_2} = 11.2\ gal$$

Gas volume at minimum operational pressure for subsea charged accumulator:

$$V_{2b} := \frac{P_1 \cdot V_{1b}}{P_2} = 14.9\ gal$$

Usable fluid for accumulators charged at surface:

$$V_a := \left\| \begin{array}{l} s \leftarrow V_{2a} \\ \text{if } V_{2a} > V_0 \\ \quad \| \, s \leftarrow V_0 \\ s \end{array} \right| - V_{1a} = 4.77\ gal$$

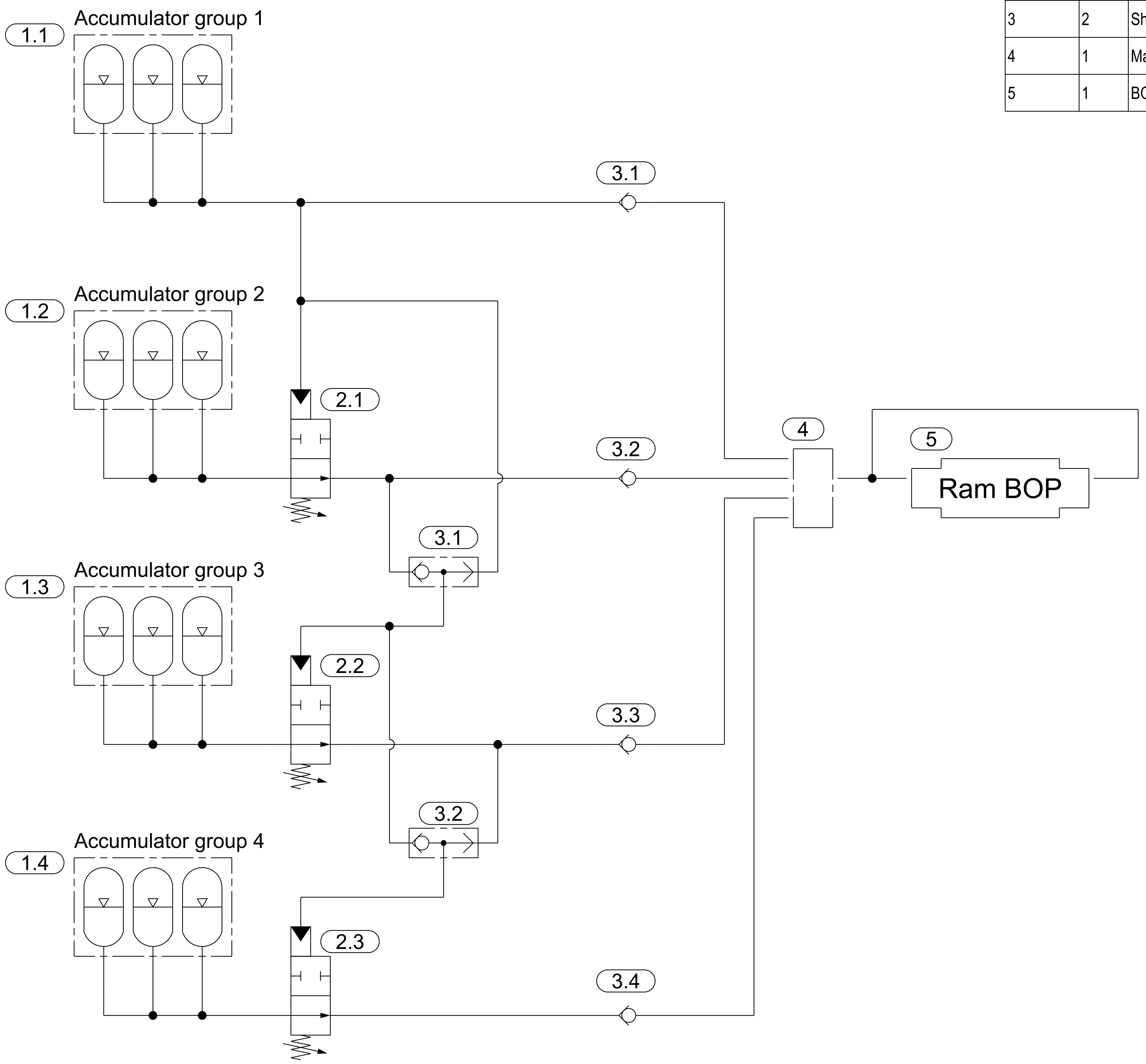
Usable fluid for accumulators charged subsea:

$$V_b := \left\| \begin{array}{l} s \leftarrow V_{2b} \\ \text{if } V_{2b} > V_0 \\ \quad \| \, s \leftarrow V_0 \\ s \end{array} \right| - V_{1b} = 8.52\ gal$$

Appendix D – Accumulators in groups

An example schematic of how accumulators could be put in groups and allow sequential operation.

Pos.	Qty.	Type	Description	Manufacturer	Remark
1	4	Accumulator group			
2	3	Pilot control valve			
3	4	Check valve			
3	2	Shuttle valve			
4	1	Manifold			
5	1	BOP Function			



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