Summary

Today, most subsea fields are developed with an electro-hydraulic control system with an umbilical providing the fields with hydraulic fluids, chemicals, signals and electrical power. The umbilical is a cost demanding component and it is of interest to simplify and standardize the umbilical in order to save costs. However, on all-electric subsea systems, valves are controlled by electric actuators, and in the future, both DHSV and the Xmas tree will be electrified. This will eliminate the need for hydraulic fluids on such fields. Required chemicals can be stored subsea, thus enabling the removal of such lines from the umbilical. As signals and electrical power can be provided to the field by a DC/FO cable, the remaining line in the umbilical is the service line.

The service line provides the field with MEG/methanol in order to perform testing of valves on the Xmas tree, testing of the DHSV and to control pressure changes experienced in Annulus A. Also, MEG/methanol is provided to the field to prevent hydrates to form within the subsea system. It is of interest to remove the service line and thus be able to operate an all-electric subsea system with a DC/FO cable only. In order to do, it has been investigated whether it is possible to perform the various task currently performed by the service line, without having a service line. Different challenges arises when the service line is removed on oil and gas producing wells, as on water and CO_2 injecting wells. These challenges have been identified and investigated. Solutions overcoming the identified challenges have also been presented and discussed.

It was found that oil and gas producing wells must be provided with MEG/methanol, as hydrates are likely to form within the subsea system. A subsea tank located close to the wellsite can provide the well with MEG/methanol when necessary. It was discovered that an oil producing well will need a fluid volume of 0.73 m^3 in order to perform the tasks once, while a gas producing well will require a fluid volume of 4.57 m^3. The size of the subsea tank will be determined by how many times the tasks are to be performed before the tank must be refilled or replaced.

Seawater can be used as test medium on water injection wells which are injecting into an active aquifer. The chances of gas migrating into the system are low on such wells, and hydrates are therefor not considered an issue. A pump, filter and a bypass valve can be installed where the service line enters the Xmas tree on today's subsea system, allowing seawater to perform the various task currently performed by MEG/methanol supplied by the service line.

Both water and CO_2 injection wells will experience big pressure changes in Annulus A. This can be controlled by placing nitrogen gas on top of the well or by a subsea accumulator tank installed on the Xmas tree. Both solutions must include a pressure intensifier in order to perform valve testing.

Sammendrag

I dag er de fleste subsea-felt utviklet med et elektro-hydraulisk kontrollsystem hvor en umbilical supplerer feltet med hydraulisk væske, kjemikalier, signaler og elektrisitet. Umbilicalen er en kostnadskrevende komponent og det er av interesse å forenkle og standardisere den for å kunne redusere kostnader. På et alt-elektrisk kontrollsystem derimot, styres ventiler av elektriske aktuatorer, og i fremtiden vil både DHSV og juletreet bli elektrifisert. Dette vil eliminere behovet for hydraulisk væske på felt utstyrt med et alt-elektrisk subsea-system. Nødvendige kjemikalier kan også lagres på havbunnen, noe som muliggjør fjerning av slike linjer i umbilicalen. Signaler og elektrisitet kan tilføres feltet med en DC/FO-kabel og den gjenværende linjen i umbilicalen er da servicelinjen. Servicelinjen supplerer feltet med MEG/metanol.

MEG/metanol tilføres feltet for å utføre testing av ventiler på juletreet, for å teste DHSV og for å kontrollere trykkendringer i Annulus A. MEG/metanol tilfører også feltet for å forhindre at hydrater dannes inne i subsea-systemet. Det er av interesse å fjerne servicelinjen og dermed kunne operere et alt-elektrisk subsea-system med en DC/FO-kabel alene. For å kunne gjøre det, er det undersøkt om det er mulig å utføre de forskjellige oppgavene som for øyeblikket utføres av servicelinjen, uten å ha en servicelinje. De ulike utfordringene som oppstår ved fjerning av servicelinjen på olje- og gassproduserende brønner, samt på vann og CO_2 injiserende brønner er identifisert og videre undersøkt. Løsninger til de identifiserte utfordringene har også blitt presentert og diskutert.

Det ble funnet at olje- og gassproduserende brønner må suppleres med MEG/metanol, da hydrater har stor sannsynlighet for å dannes inne i subsea-systemet på slike brønner. MEG/metanol kan suppleres til brønnen fra en tank plassert på havbunnen. Det ble oppdaget at en oljeproduserende brønn vil trenge et fluidvolum på 0,73 m^3 for å kunne utføre de oppgitte oppgavene én gang, mens en gassproduserende brønn vil kreve et fluidvolum på 4,57 m^3. Størrelsen på tanken må bestemmes ut ifra hvor mange ganger oppgavene skal utføres før tanken må etterfylles eller eventuelt byttes ut.

Sjøvann kan brukes som testvæske på vanninjiseringsbrønner som injiserer inn i en aktiv akvifer. Sannsynlighet for at gass migrerer inn i brønnen under slike forhold er lav, og det er derfor lav sannsynlighet for at hydrater dannes inne i subsea-systemet. En pumpe, filter og en bypass-ventil kan installeres der hvor servicelinjen entrer juletreet på dagens subsea-system. Sjøvann kan da brukes til å utføre de forskjellige oppgavene som for øyeblikket utføres av MEG/metanol levert av servicelinjen.

Både vann og CO_2 injiserende brønner vil oppleve store trykkendringer i Annulus A. Dette kan kontrolleres ved å plassere nitrogengass på toppen av brønnen eller ved å installere en akkumulatortank på juletreet. Begge løsningene må inneholde en trykkforsterker slik at testing av ventiler også kan utføres på brønnen uten bruk av servicelinjen.

Acknowledgement

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Hanne Fuglestad

Hanne Fuglestad
Trondheim, 31.01.2020

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Abbreviations

AIV	=	Annulus Isolation Valve
AMV	=	Annulus Master Valve
AVIV	=	Annulus Vent Isolation Valve
AVV	=	Annulus Vent Valve
AWV	=	Annulus Wing Valve
BMV	=	Bleed Monitoring Valve
CAPEX	=	Capital Expenses
ccm	=	cubic centimeter
CIV	=	Chemical Injection Valve
DC/FO	=	DC power and Fiber Optics
DHSV	=	Downhole Safety Valve
HSE	=	Health Safety and Environment
IMR	=	Inspection, Maintenance and Repair
MCS	=	Master Control Station
MEG	=	Monoethylene Glycol
MEGIV	=	MEG Isolation Valve
OPEX	=	Operating Expenses
PBT	=	Plug Bleed and Test Valve
PCV	=	Production Choke Valve
PMV	=	Production Master Valve
PWV	=	Production Wing Valve
ROV	=	Remotely Operated Vehicle
SCM	=	Subsea Control Module
SCS&I	=	Subsea Chemicals Storage & Injection
WCIV	=	Workover Chemical Injection Valve
WOV	=	Workover Valve
XOV	=	Crossover Valve

Chapter 1

Introduction

1.1 Motivation

Today, most subsea fields are developed with a Multiplexed electro-hydraulic control system with umbilicals providing the fields with hydraulic fluids, chemicals, signals and electric power. With production moving into deeper water depths and to more remote locations, higher requirements are set to the umbilical. As a result, the complexity of the umbilical increases and the cost increases accordingly. Thus, it is of interest to simplify and standardize the umbilical in order to save costs.

The trend in subsea technology is heading towards the implementation of all electric solutions. With the implementation of an all-electric control system, the valves on the Xmas tree are operated by electric actuators rather than hydraulic fluids as the multiplexed electro-hydraulic control system is. There are currently several on-going qualification projects to provide electrically actuated Xmas tree and downhole safety valves, which in turn will make the subsea system fully electric. With this system, the need for hydraulic fluid is completely removed. Also, subsea storage of chemicals and other solutions related to distribution of chemicals are being developed. The remaining required functions supplied by the umbilical are signals, electrical power and MEG/methanol. Signals and electrical power may be provided by simple fiber and power cables such as DC/FO cables. DC/FO cables are qualified and will be used on the Johan Castberg field in the Barents Sea for instance. MEG/methanol may be supplied to the field by a separate service line.

The service line supplies the subsea field with MEG/methanol for several reasons. Some of the tasks enabled by the service line are difficult to perform without MEG/methanol, such as inhibition to prevent hydrate formation in the subsea system for instance. However, other tasks can potentially be solved without using MEG/methanol. The probability of experiencing hydrate formation in Xmas trees injecting water is less than on oil and gas producing wells. It is possible that such wells can be operated without MEG/methanol supplied by the service line. However, the service line is still required for other purposes.

These are listed below.

- Test of subsea trees, i.e. test of selected Xmas tree valves
- Pressure equalizing across valves prior to opening
- Control of Annulus A pressure during shut-downs and start-up of a well

If these tasks can be performed without the service line, the service line can be excluded on future developments and the development can be operated by a DC/FO cable alone. This will make field developments simpler, cheaper, more standardized and without any limitations to tie back lengths.

In the beginning of year 2020 Equinor, together with LO and NHO, announced that they will cut emissions drastically on the Norwegian continental shelf. The goal is to cut emissions by 40 % by 2030, compared to 2005. In 2050, they expect the Norwegian oil production to be emission-free. Carbon capture and storage will play an important role in achieving this. Thus, the number of CO_2 injection wells are expected to increase in the years to come. New solutions are required in order for the production on the Norwegian continental shelf to remain profitable and at the same time become emission-free. Removing the service line can be a solution that brings this one step closer to becoming possible. The Northern Light project is an example of where this would be of great interest.

1.2 Objective

The objective of this Master thesis has been to study whether it is possible to perform valve testing on the Xmas tree and to control annular pressure on subsea production and injection wells without using the service line. The different type of wells will face different challenges for this to become achievable. Challenges that arise with the removal of the service line on oil producing wells, gas producing wells, water injection wells and CO_2 injection wells will be specified and investigated. Solutions enabling the removal of the service line on the different type of wells will be presented and discussed. Also, a literature review on relevant topics will be performed.

Solutions that will be investigated:

- Performing valve testing and control pressure changes experienced in Annulus A by storing MEG/methanol in a subsea tank close to the wellsite. A pump will be required to transfer fluid from the tank to the well when needed.
- Controlling annular pressure changes by placing nitrogen gas on top of the well, which will respond to pressure changes by expanding/contracting.
- Performing valve testing and annular pressure control with seawater as test medium.
- Performing valve testing and annular pressure control by an subsea accumulator tank and a pressure intensifier

1.3 Outline of the Thesis

- Chapter 1: Presents the introduction, including the motivation and objective of this thesis.
- Chapter 2: This chapter includes a literature review on subsea control systems, umbilicals, DC/FO cables, service line requirements, the Xmas tree, flow assurance challenges, subsea chemical storage and tanks and pump specifications.
- Chapter 3: The different service line requirements are described and specified in this chapter.
- Chapter 4: The challenges of removing the service line on the different well types are specified and discussed. Solutions that allow removal of the service line on the various wells are also presented in this chapter.
- Chapter 5: The solutions are discussed further with a focus on the aspect of safety, emissions and economy.
- Chapter 6: The conclusion is given.

Chapter 2

Literature Review

Petroleum production is directed towards deeper water depths and to more remote locations, and higher requirements are set to the subsea developments operating under such conditions. In order to optimize the production and be able to remain a profitable production, the subsea technology must be further developed. Today's subsea system are complex and requires specialization for each field. Thus, standardization and simplification of today's subsea system is necessary. Digitalization of the system will also be an important factor in the years to come.

The trend in subsea technology is heading towards all-electric subsea systems. With an all-electric subsea systems, electrical actuators are installed on the Xmas tree enabling electrified monitoring. Until now, most subsea systems have been controlled by and electro-hydraulic system. With this system, a two parallel energy systems with both power cables and hydraulic lines are included in the umbilical connecting the topside to the subsea development. By replacing the electro-hydraulic system with an all-electric system, the need for hydraulic lines is removed. With the all-electric subsea system the complexity of the system is reduced, limitations to tieback lengths are gone, the risk of hydraulic leaks is gone and the HSE are improved as the exposure of hydraulic fluids is removed. According to Abicht et al. (2017), all-electric systems are simpler, more flexible, standardized and cheaper compared to the electro-hydraulic systems utilized today.

The implementation of all-electric subsea systems are already taking place. Currently, electric actuators on branch valves, chokes and process control valves are being utilized. Further implementation strategy is to electrify the Xmas tree and the DHSV (Abicht et al., 2017).

As the implementation of all electrical subsea systems continues, new solutions are being developed simultaneously assisting the simplification of the systems. Topics related to the subsea development are provided in this chapter.

2.1 Subsea Control Systems

A subsea control system is an essential part on each subsea development. The control system has several important tasks, with the most fundamental ones being to open and close valves and chokes on the various subsea production equipment. The control system provides communication between topside and the subsea development, enabling monitoring of production parameters such as temperature, pressure and sand detection (Bai and Bai, 2018). Overall, the control system provides system integrity and makes it possible to optimize the production.

As the development of control systems started in the 1960s, five different types of control systems have been designed. This include Direct hydraulic, Piloted hydraulic, Sequenced hydraulic, Multiplexed electro-hydraulic and All-electric control systems. According to Bai and Bai (2018), most subsea systems are equipped with a Multiplexed electrohydraulic control systems. However, Equinor launched in 2010 an All-Electric Subsea initiative, where they consider All-electric control systems as the main option for subsea production systems in order to meet future system requirements (Abicht et al., 2017). Both the Mulitplexed electro-hydraulic control system the All-Electric control systems are further described in this chapter.

2.1.1 Multiplexed Electro-Hydraulic Control Systems

A multiplexed electro-hydraulic control system is defined by Bai and Bai (2018) as “a subsea computer/communication system consisting of hydraulic directional control valves.” With an multiplexed electro-hydraulic control system, the valves are actuated by electrical signals and operated by pressure stored in subsea accumulators. The stored pressure is charged by hydraulic fluid which is supplied to the field through hydraulic lines in the umbilical. The control system includes a Master Control Station (MCS) and a Subsea Electronics Module (SEM). The MCS is implemented by a computer, which communicates with the SEM via microprocessors. In this way, the various MCS functions can be performed (Bai and Bai, 2018).

A multiplexed electro-hydraulic control system has the advantage that the electrical and hydraulic power supplied to the field through a conventional umbilical can be distributed over several SCMs. This makes it possible to control many wells by one umbilical (Bai and Bai, 2018). A multiplexed electro-hydraulic control system, with its main component, is illustrated in Figure 2.1, while advantages, disadvantages and prominent features with the control system are listed in Table 2.1. The table was originally made by Bai and Bai (2018).

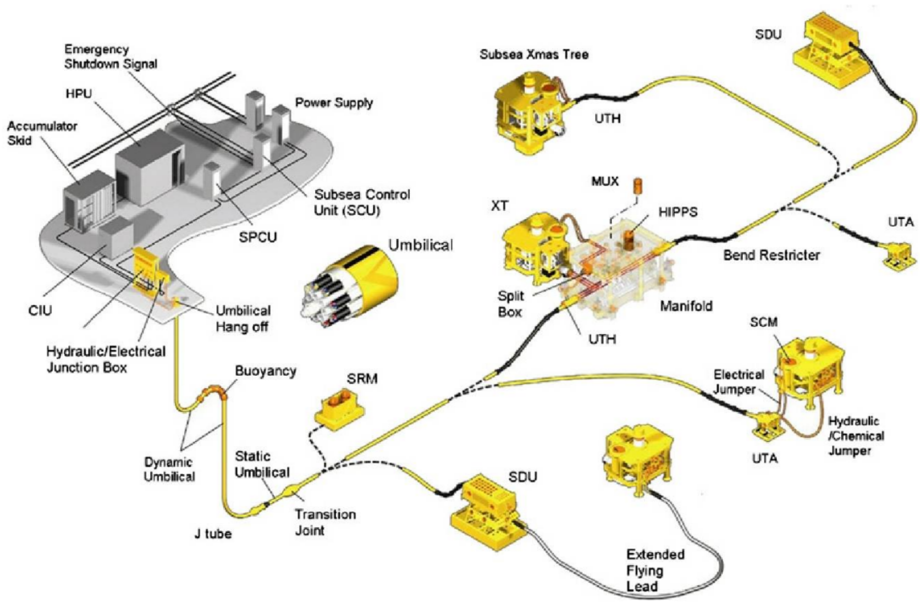


Figure 2.1: An overview of a subsea control system (FMC Technologies, 2012)

Table 2.1: "Prominent Features, Advantages, and Disadvantages of Multiplexed Electro-Hydraulic Control Systems"

Advantages	Disadvantages	Prominent Features
Give good response times over long distances	High level of system complexity	Real-time system response
Smaller umbilical diameter	Requires subsea electrical connectors	Virtually no distance limitations
Allows control of many valves/wells via a single communication line	Increase in surface components	Maximum reduction in umbilical size
Redundancy is easily built in	Increase in subsea components	Subsea status information available
Enhanced monitoring of operation and system diagnostics	Recharging of the hydraulic supply over such a long distance	High level of operational flexibility
Ideal for unmanned platforms or complex reservoirs	Hydraulic fluid cleanliness	
Able to supply high volume of data feedback	Materials compatibility	
No operational limitations		

2.1.2 All Electrical Control Systems

An all electrical control system is defined by Bai and Bai (2018), as "an all-electric-based system without the conventional hydraulic control of subsea components". With such a control system, valves and chokes on the Xmas tree are activated by electrical actuators. The Xmas tree are fitted with dual, all-electric SCMs, supplying power and signals to each electrical actuator. The actuators are operated by rechargeable Li-ion batteries (Bai and Bai, 2018). An All Electrical control system is illustrated in Figure 2.2.

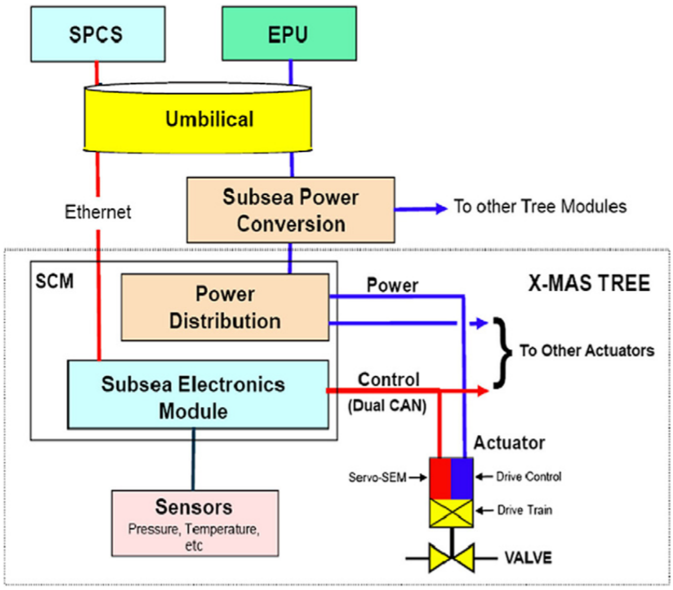


Figure 2.2: "All Electrical control system" (Bai and Bai, 2018)

All electrical control systems uses electrical power rather than hydraulic power to control valves and chokes on the subsea system. This comes with several benefits. Since the hydraulic lines are removed, the retardation time related to charging accumulators are reduced. The control system commands can be sent in rapid succession without any delays (Bai and Bai, 2018). As hydraulic fluid is no longer needed on an all-electric control system, the hydraulic lines in the umbilical can be removed. Thus, the diameter of the umbilical is reduced, reducing the cost related to the umbilical. This could increase the profit when developing marginal fields with long tieback lengths. With the control system, it is easier to further develop and expand an existing system and also to implement new equipment into the system. By implementing an all-electric control system, flexibility is added to the development. In addition, both personal and environmental HSE are improved as exposure to the hydraulic fluids disappears (Abicht et al., 2017).

2.2 Conventional Umbilicals

A multiplexed electro-hydraulic control system is supplied with electrical and hydraulic power through a conventional umbilical. The umbilical makes up the connection between the host and the subsea facility, with the umbilical attached to the host by an hydraulic/electrical junction box and to an umbilical termination assembly (UTA) at the subsea facility. From the junction box, the umbilical goes into a dynamical section called a catenary riser, before it transitions into a static section which goes along the seabed and ends up in the UTA (Bai and Bai, 2018).

The umbilical is made up by several cables which are assembled to form a circular cross section. The cables include electrical cables, fiber optic cables, steel tubes, fillers and thermoplastic hoses. An umbilical may consist of two or three of the components depending on which functions to be performed on the subsea field (Bai and Bai, 2018). A cross-section of an umbilical is illustrated in Figure 2.3.

The electric cable, which consists of one power cable and one signal/communication cable, supplies the subsea facility with electrical power and enables control and/or monitoring of the various subsea components. The fiber optic cable enables data transfer between the host facility and the subsea development while the steel tube component enables transportation of hydraulic control fluids and/or injection chemicals. The service line, which is in focus throughout this thesis, is such a steel tube. The thermoplastic hoses distributes fluids/chemicals and supports chemical injection and provides hydraulic control (Bai and Bai, 2018). As shown in Figure 2.3, shafts are added to the umbilical in order to protect the various cables making up the umbilical. Steel armour wires are installed between the inner and outer sheath to increase the stability of the umbilical (Lu et al., 2014). However, steel armor wires are only included in the dynamic part of the umbilical, as this part will be subjected to greater forces generated by waves and ocean currents. The static part of the umbilical does not need reinforcement as it lies on the seabed (Equinor, 2019c).

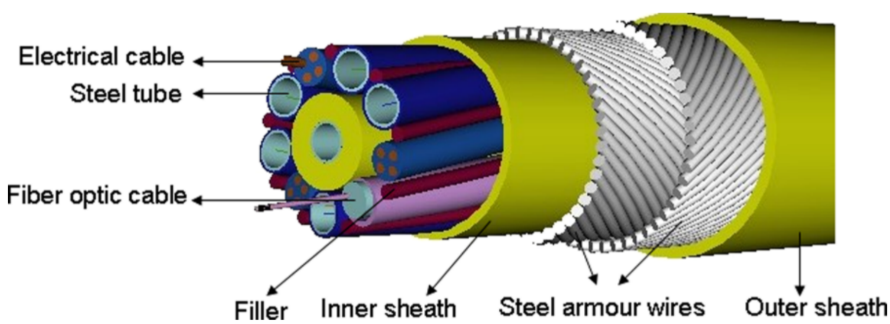


Figure 2.3: A cross section of an umbilcial showing the different types of cables (Lu et al., 2014)

Conventional umbilicals are expensive and makes it difficult to profitably develop marginal fields with long tie-back lengths. It has therefore been launched several qualification projects to explore the possibility of providing the required features for subsea developments by using a more modified umbilical. As described above, the all electric control systems does not need hydraulic fluid as the multiplexed electro-hydraulic control system does. If an all-electric control system, together with an electrified Xmas trees and DHSV, are implemented to the subsea system, the remaining features are the supply of signals, electrical power and MEG/methanol. Signals and electrical power can be supplied to the field by a DC/FO cable, which is further described below.

2.3 DC/FO Cables

DC/FO cables are simple fibre and power cables which can supply subsea fields with low voltage DC and optical fiber communication over long distances. DC/FO in an abbreviation for DC power and Fiber Optics. The cables are originally used in submarine telecommunication systems, enabling the transmission of WIFI signals between continents. DC/FO cables are developed by Alcatel Submarine Networks and the company has installed cables for submarine telecommunication systems for 150 years. The implementation of the technology to subsea systems is a cooperation between Alcatel, Equinor and Chevron. The technology is field proven and has, according to Michel et al. (2017), showed to be a reliable and flexible solution. For submarine telecommunication systems, the cables are installed at a water depth up to 3000 m and has shown to require one repair every 25th year (Michel et al., 2017). The cables are also tolerant for insulation in case of external aggression. This was experienced after an earthquake in Fukushima. The cables were damaged but kept powered and in service until the repair, which was performed by a cableship a few days after the aggression (Michel et al., 2017).

As described in Chapter 2.2, increasing tieback lengths and power consumption leads to an increased cross-sectional area of the umbilical. The cost related to the umbilical increases with increasing cross-sectional area. According to Michel et al. (2017), the implementation of DC/FO cables to the subsea system, overcomes limitations concerning tie-back lengths and loss of power along the umbilical. The replacement of the conventional umbilical with a DC/FO cable would also result in a standardization of the cable supplying the subsea field with signal and electrical power. Unlike conventional umbilicals, which are designed for the functions to be performed on the subsea field, DC/FO cables have the same cross-sectional area regardless of the functions to be performed on the subsea field. The result is a significantly downsizing of the cross-sectional area of the umbilical, which will in turn lead to reduced costs regarding the umbilical. The downsizing of the umbilical made possible by the implementation of an all-electric subsea systems together with a DC/FO cable, is shown in Figure 2.4.

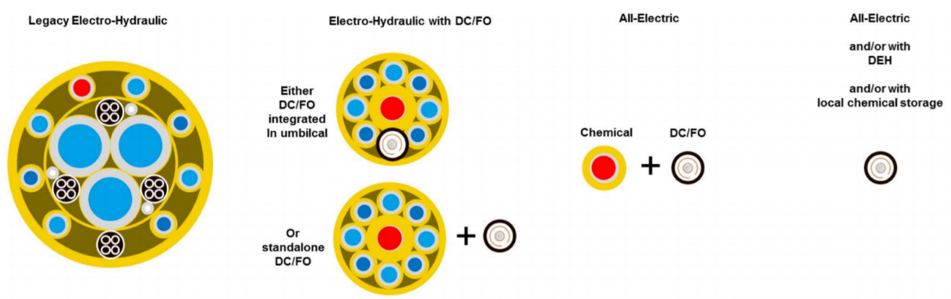


Figure 2.4: "Umbilical downsizing" (Michel et al., 2017)

2.4 Service Line Requirements

As previously described, an all-electric subsea system does not require hydraulic fluid to control the valves and chokes on the subsea system. By implementing an all-electric subsea system together with a DC/FO cable, the remaining line in the conventional umbilical is the service line. The service line provides the subsea field with MEG/methanol in order to perform several tasks. As illustrated in Figure 2.4, it is desirable to also remove the service line so that a field can be operated by a DC/FO cable alone.

The service line provides the subsea field with MEG/methanol. MEG or methanol are supplied to the field in order to perform several tasks. These tasks are listed below.

1. MEG/methanol is supplied to the field in order to prevent formation of hydrates within the subsea system. It is also provided to treat other flow assurance related problems.

2. The service line is used to achieve a differential pressure of 70 bar across a valve during testing of the Xmas tree and the DHSV.

3. After testing, the service line is used to equalize the created differential pressure across a valve before it is opened.

4. The service line is used to control pressure changes experienced in Annulus A.

The listed tasks will be further described and specified throughout this thesis. A presentation of the Xmas thee is provided below in order to specify the need for MEG/methanol during testing of the valves on the Xmas tree.

2.5 Xmas tree

The Xmas tree is the primary well control module. It contains a control system and various valves, sensors and actuators. The valves are controlled by the control system, which supply the system with electric and hydraulic power and communication signals. The control system also distributes chemicals and methanol out to each well. The different valves located on the Xmas tree are used for testing, servicing, regulation or choking the production stream (Bai and Bai, 2018). Changes in the production stream are caught up by the sensors which sends control input over to the actuators. The actuators generate a change in the physical system, by for instance producing force, heat or motion.

The main functions of the Xmas tree are listed below (Bai and Bai, 2018).

- Make up the connection between the well and the flowline, so that the fluid can flow from the well and up to surface or the opposite way on injection wells.
- Monitor well parameters, such as well pressure, annuls pressure, temperature, sand detection.
- The Xmas tree is part of the primary safety barrier, which means that the tree must be able to stop the flow of fluid when necessary.

As illustrated in Figure 2.5, the Xmas tree contains several valves. The DHSV is the first valve the production stream flows through and is considered the primary pressure barrier. The DHSV is a fail-safe-close valve, which means that it is actuated to close by a powerful mechanical spring. DHSV will be activated if it detects any deviations in the well, such as a leak or a pressure build-up (Alstad, 2011).

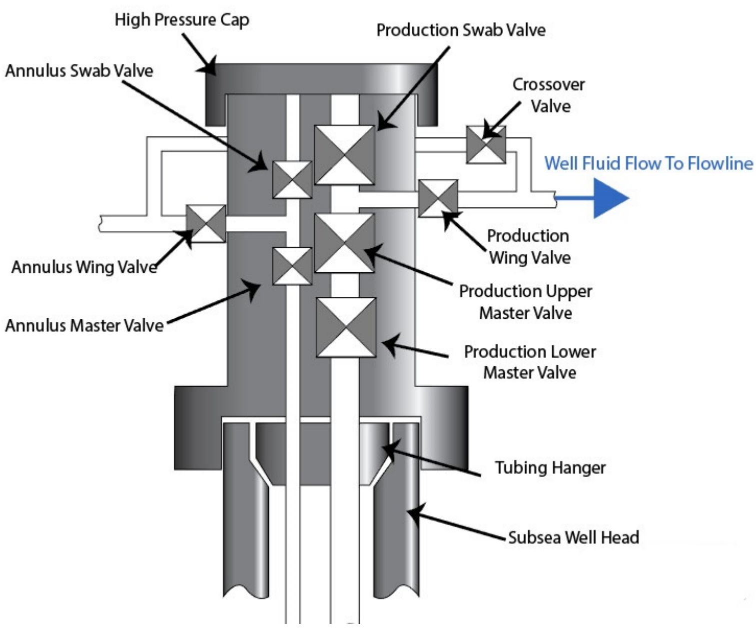


Figure 2.5: A scematic of a vertical Xmas tree schematic. The Xmas tree is equipped with two master valves, which is not common practice (DrillingFormulas.com, 2016)

The Production Master Valve (PMV) is located above the DHSV and is part of the second pressure barrier system. Both the PMV and the DHSV are barrier valves and must be designed to withstand full reservoir pressure. Should an emergency occur, or if the well must be shut down due to other reasons, the barrier valves must be able to shut in the well (Alstad, 2011). When shutting in the well, the flow and the pressure within the production stream are regulated by the production choke valve (Bai and Bai, 2018). The DHSV, PMV and wing valve are kept open during production under normal conditions, while the production and annulus swab valves are kept closed. The annulus contains several valves, among them the Annulus Master Valve (AMV) and the Annulus Access Valve (AAV). These two valves are, according to Bai and Bai (2018), "used to equalize the pressure between the upper space and lower space of the tubing hanger during the normal production. When well intervention is performed, access to the wellbore and annulus are provided by the Production Swab Valve (PSV) and Annulus Swab Valve (ASV)".

A Crossover valve (XO-valve) is located in the main bore and provides flow and pressure communication between the annulus and the main bore. Should an excessive pressure arise in the annulus, the pressure increment is bled off by closing one of the barrier valves located in the main bore while one of the annulus barrier valves and the XO-valve are kept open (Bai and Bai, 2018). In addition to provide communication between the main bore and the annulus, the XO-valve can, according to Bai and Bai (2018), "be used to allow fluid passage for well kill operations or to overcome obstructions caused by hydrate formation".

Testing procedures for the various valves on the Xmas tree and the DHSV are provided in Chapter 3.1.

2.6 Flow Assurance Challenges

Flow assurance means to protect and insure a successful and economic flow of hydrocarbons throughout the pipeline system of the well (Teixeira et al., 2017). During the lifetime of a well, flow assurance challenges such as the formation of hydrates, wax, scale, asphaltenes and emulsions may take place. Corrosion is also considered a challenge. If such issues remain untreated, they can lead to a blockage of the production system or unstable production flow. In order to avoid this, chemicals are injected into the system through injection points located in the subsea system. Several of the flow assurance challenges are described in this chapter.

2.6.1 Hydrates

Hydrates are crystalline compounds that forms when water and gas are combined under certain pressure and temperature conditions. Hydrates can form anywhere and at any time in a production system as long as the system is kept under these conditions (Teixeira et al., 2017). Petroleum production has over the years moved into deeper and deeper water depths. With increasing water depth, the hydrostatic pressure increases and if the temperature of the sea is low enough, hydrates will begin to form. Figure 2.6 shows the temperature and pressure conditions at which hydrates begin to form.

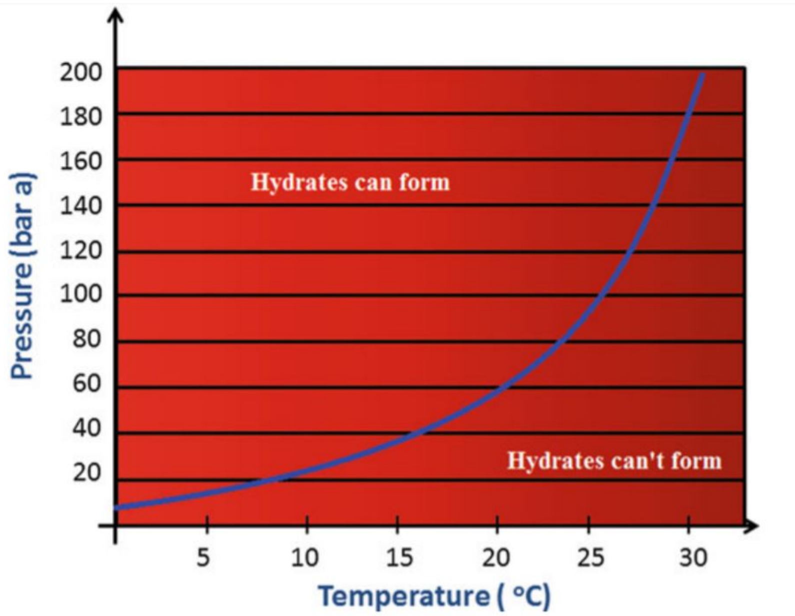


Figure 2.6: The curve shows at which conditions hydrates will form (Teixeira et al., 2017)

Both oil and gas producing wells are vulnerable for hydrate formation. This especially concerns during start-up and shut-down of a well. During start-up, the subsea system itself is cold and if the system contains gas molecules, hydrate formation conditions are achieved. During shutdown of the subsea system, the temperature may drop sufficiently for production to fall within the hydrate formation window (Teixeira et al., 2017).

Hydrates can lead to plugging of flowlines, valves, and other subsea devices which can be a time-consuming issue to treat. An example of flowline plugging is shown in Figure 2.7. It is especially important that the DHSV is kept out of hydrate formation conditions as it is part of the primary pressure barrier system. The valve is placed at a depth so that the temperature from the production stream is high enough to keep the valve outside the hydrate formation window during operation. If hydrates are formed across the DHSV, the primary well barrier is lost (Sangesland et al., 2012).

For subsea systems where hydrate are likely to form, MEG or methanol is continuously injected into the system to prevent plugging of the system. By injecting MEG or methanol, the hydrate formation curve is shifted to the left, enlarging the non-hydrate formation window. With increasing composition of MEG injected into the production stream, the larger the non-hydrate window becomes (Teixeira et al., 2017).

Figure 2.7: Hydrates plugging a flowline on a gas producing well (Jozian and Vafajoo, 2018)

2.6.2 Wax

Wax deposits starts to form during depressurization of the pipelines on oil producing wells. If the temperature of the oil drops below the cloud point, the light molecules of the oil start to vaporize. As the light molecules vaporize, the temperature of the oil drops. This causes the remaining oil molecules to crystallize. The result is long chained molecules that can lead to reduced flow rates, and if not treated, a total blockage of the pipeline. Wax deposits are treated with pigging, inhibitor injection and thermal insulation (Sousa et al., 2019).

2.6.3 Scale

Scale are salt deposits that forms on wells producing formation water. Formation water are often over-saturated with various salts. When produced water is combined with hydrocarbons, and the mix is exposed to temperature and pressure changes, salts will start to crystallize and precipitate from the production stream. A coating is formed on the inside of the production system, reducing the cross-sectional area of the pipeline. Without treatment, scale can lead to plugging of perforations, valves, pumps and other completion equipment (Bai and Bai, 2018).

To prevent salt precipitation, inhibitors are injected continuously into the production flow. The inhibitors slows down the formation of scale. In severe occasions, scale must be treated mechanically. Figure 2.8a shows a pipeline with scale deposits.

2.6.4 Corrosion

Internal corrosion of the production pipeline system occurs due to high salt content in the production stream. As the production flow contains corrosive components, such as CO_2, H_2S, formation water, chloride among others, a corrosive environment is created. Internal corrosion can be either sweet or sour. Sweet corrosion occurs in system producing a high amount of CO_2, while sour corrosion occurs in system producing high amounts of H_2S (Bai and Bai, 2018). Corrosion is treated in the same way as scale. Inhibitors are injected continuously to prevent the appearance of corrosion . Internal corrosion can, in a worst case scenario, lead to leakage along the pipeline (Bai and Bai, 2018). Figure 2.8b shows the inside of a pipe where internal corrosion has occurred.

(a) Scale deposits (Sandengen, 2019) **(b)** Internal corrosion (Askari et al., 2019)

Figure 2.8: Examples of scale deposits and internal corrosion of a pipe

2.7 Subsea Chemical Storage

As previously described, it is of interest to be able to operate an all-electric subsea system field with a DC/FO cable alone. In order to do so, the service line must be removed and chemicals must be stored subsea. Since hydrate formation and other flow assurance related problems will continue to be an issue for both production and injection wells, it will not be possible to stop the supply of chemicals completely. Thus, it will be necessary to store chemicals on the seabed.

Total has come up with a solution for storing chemicals in tanks at the seabed, near the wellsite. The solution, named Subsea Chemicals Storage & Injection-station (SCS&I) consists of several tank modules containing different chemicals. Each module contains four tanks in addition to equipment and functional system. According to Festøy and Lundal (2017), "each tank module has a total storing tank capacity of $30m^3$, which means that each subsea chemical storage tank stores $7.5m^3$". Calculations performed by Peyrony and Beaudonnet (2014), shows that it is more profitable to replace the tank modules rather than refilling them. The weight of the modules cannot exceed 70 tonnes due to limitations in the crane capacity of the vessel performing the replacement of the modules. Figure 2.9 shows an illustration of the Subsea Chemicals Storage & Injection-station.

The solution with storing chemicals in such modules comes with several benefits. According to Peyrony and Beaudonnet (2014), HSE are improved, more space is made available at topside and response time with injection of the chemicals are significantly reduced as chemicals are stored closer to the injection points. During start-up and shutdown operations, inhibitors will be injected instantly, reducing hydrate formation in these scenarios. Usually are production chemicals injected at low rates demanding accurate doing of the chemicals. According to Festøy and Lundal (2017), the local storage of chemicals makes it possible for the injection pumps to dose the required amount of production chemicals more easily. Studies performed by Peyrony and Beaudonnet (2014) shows that such SCS&I-stations are economical beneficial when tie-back lengths exceed 24 kilometres. The topic is further discussed in the thesis written by Festøy and Lundal (2017).

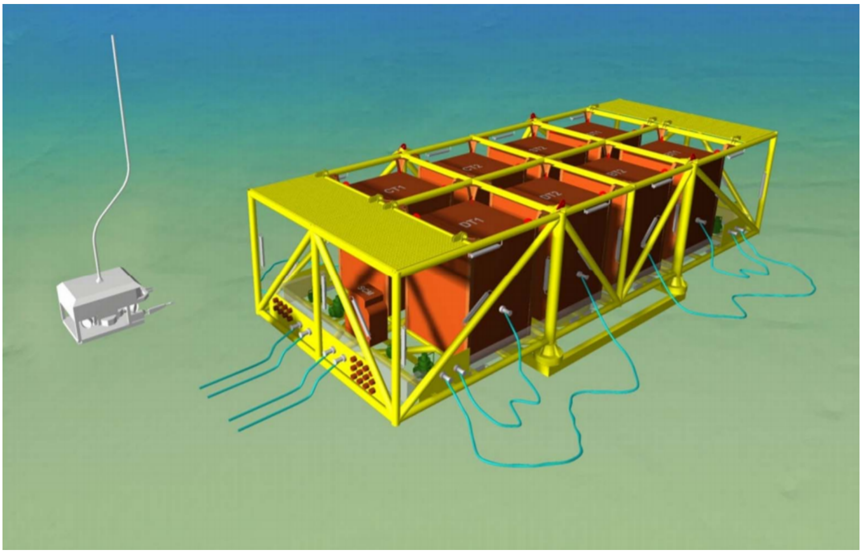


Figure 2.9: A Subsea Chemicals Storage Injection-station (SCS&I) designed by Total and Doris Engineering (Peyrony and Beaudonnet, 2014)

2.8 Tank Specifications

By storing chemicals subsea, the tank containing the chemicals must be carefully selected. There are several types of tanks suitable for subsea chemical storage, some of which are described below.

2.8.1 Bladder Tank

A bladder tank consists of two chambers created by an elastic bladder, which contains two different fluids. The tank has two inlets, one at the top and one at the bottom of the tank. If the upper chamber is filled with liquid, the expanding volume of the upper chamber pushes the fluid in the lower chamber out of the lower inlet. If the lower chamber is filled with fluid, the process is reversed: the expanding volume of the lower chamber pushes the fluid inside the upper chamber out of the upper inlet (Festøy and Lundal, 2017). Such a process is depicted in Figure 2.10. The bladder tank is developed by NOV in collaboration with

Equinor (Equinor, 2019a).

As the construction consist of the structure itself and the bladders inside, the tank is considered as a two-barrier system (Festøy and Lundal, 2017). This makes it suitable for subsea chemical storage, as a two barrier system is required. Should the bladders fail, the leakage would be stopped by the tank structure. According to Festøy and Lundal (2017), a bladder tank is cheap compared to other tanks capable of storing the same volume.

Figure 2.10: The process of filling the bladder in a bladder tank (Equinor, 2019a)

2.8.2 Piston Tank

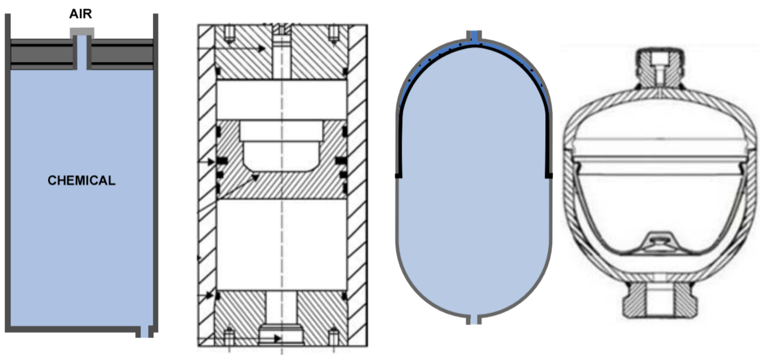
A piston tank is basically a large plunger which moves up and down inside an enclosed cylinder. The plunger, or piston, separates two fluid-containing chambers, as illustrated in Figure 2.11a. Fluid in the lower chamber is pumped out of the inlet at the bottom of the tank as the piston is pushed downwards. The process is reversed when the piston is pulled upwards. The piston is equipped with two elastomer seals that prevents the two fluids in the tank from mixing. As the piston moves up and down, the construction will experience pressure changes. Care must be taken during the design and construction of the piston tank so that the various components of the tank are able to withstand the pressure changes (The SubCommittee, 2015).

A piston tank must operate under the condition that the piston in the tank moves perfectly up and down. If perfect movements of the piston are not achieved, the two fluids will start to mix. However, the tank has a heavy and robust construction suitable for chemical storage (Peyrony and Beaudonnet, 2014).

2.8.3 Membrane Tank

Membrane tanks are non-self-supported cargo tanks surrounded by either one or two membranes. If the tank has two membranes, it is considered as a two-barrier system. These tanks have a sandwich construction, with the following layout: A primary membrane, a layer of insulation, a second membrane and a second layer of insulation (Mokhatab et al., 2013). Figure 2.11b shows a schematic of a membrane tank.

The insulation layer between the membranes are load bearing. According to Lees (2012), "the membrane tank consists of a pre-stressed concrete containment with an aluminium foil membrane." With this construction, the temperature of the tank contents is kept low. The membranes are also designed and constructed to withstand the forces exerted on it during operation. This include, according to Lees (2012), thermal and other expansion or contraction forces. Membrane tanks are mostly used for storage of liquefied natural gas (Lees, 2012).



(a) Piston Tank **(b)** Membrane Tank

Figure 2.11: Tank schematics (Peyrony and Beaudonnet, 2014)

2.8.4 Rolling Tank

A rolling tank is a rolling diaphragm bladder-containing structure. This type of tanks have a two-barrier system, which makes leakage to the environment less likely. When the fluid-containing bladder is compressed, the fluid is squeezed out at the bottom of the tank (Festøy and Lundal, 2017). The process is illustrated in Figure 2.12 where the outlet of the tank is marked with a green arrow. As the bladder empties, another fluid will begin to refill the released space within the structure. It is often seawater that fills this space, and it enters the tank at the top of the structure which is marked with a blue arrow in Figure 2.12. The tank is not vulnerable to imperfect bladder movements such as the piston tank, so mixing of the two fluids is unlikely. However, the tanks are, according to Peyrony and Beaudonnet (2014), heavy and not very chemically compatible compared to other types of tanks.

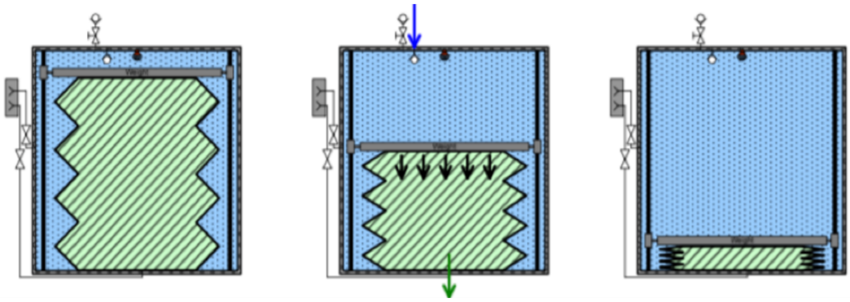


Figure 2.12: The process of emptying a rolling tank (Festøy and Lundal, 2017)

2.8.5 Pillow Tank

Pillow tanks are, as the name implies, large pillows made out of a strong and elastic material. Unlike the other types of tanks described in this chapter, the pillow tank has only one barrier making it a one-barrier system. According to Canflex Inc (2017), pillow tanks have a storage capacity ranging from 1 m^3 to 1000 m^3. The tanks are used in several industries, such as aerospace, defense and consumer products with a waterbed mattress as an example. A pillow tank is depicted in Figure 2.13.

Figure 2.13: A pillow tank storing 190 m^3 of fluid (Canflex Inc, 2017)

Since the structure of the pillow tank is elastic, the contraction during deflation of the tank will occur evenly over the entire structural surface of the tank. This means that the pressure inside the tank will stay approximately constant during deflation. This is an advantage for subsea chemical storage (Equinor, 2019c). However, pillow tanks are large constructions that require a significantly large area of the seabed if used in subsea chemical storage.

Pros and cons with the different types of tanks are listed in Table 2.2. The table was originally made by Peyrony and Beaudonnet (2014).

Table 2.2: Pros and cons of the different types of tanks

	Piston tank	**Elastic bladder tank**	**Membrane tank**	**Rolling tank**	**Pillow tank**
Weight	+	+	+	-	-
Chemical compatibility	+	-	-	-	-
Monitoring	+	-	-	+	+
Filling and maintenance	+	-	-	+	+
Manufacturability	+	-	-	-	-

2.9 Pump Specifications

When storing chemicals on the seabed, the chemicals in the tanks must be transported from the tank to the well when needed. Therefor, a pump is required. As for the tank, the pump must be carefully selected. Below is a description of several pumps. There are two main types of pumps: positive displacement pumps and centrifugal pumps.

2.9.1 Positive Displacement Pumps

Positive displacement pumps are defined by Michael Smith Engineers (2020a) as pumps that “moves a fluid by repeatedly enclosing a fixed volume and moving it mechanically through the system.” Positive displacement pumps include a variety of designs, but common to all types is that the movement of the pumps is cyclic. The movement can be driven by pistons, gears, rollers, diaphragms or blades, the design of which are described below. Positive displacement pumps are suitable when working with viscous fluids, high pressures and when accurate dosing is required (Michael Smith Engineers, 2020a).

There are in general two types of positive displacement pumps: reciprocating and rotating pumps. Reciprocating positive displacement pumps transfer fluid by moving a component back and forth while rotating positive displacement pumps utilises rotating cogs or gears.

Piston Pump

A piston pump is a type of reciprocating positive displacement pump. A piston pump consists of a back-and-forth moving piston, a piston chamber and two valves. As the piston is moved to the left, a vacuum is created in the piston chamber. Simultaneously, the inlet valve is opened, the outlet valve is closed and fluid is drawn into the piston chamber. The movement is called a suction stroke. The process is reversed and the piston is moved to the right. The inlet valve closes while the outlet valve opens, and the fluid in the piston chamber is discharged. The movement is called a compression stroke. The process is illustrated in Figure 2.14. To increase the efficiency of a piston pump, the pump can be double-acting, which means that an inlet and an outlet valve are installed on both sides of the piston. When the piston is drawing fluid into the piston chamber on one side of the pump, fluid is compressed on the other side of the chamber simultaneously (Michael Smith Engineers, 2020a).

Plunger Pumps

A plunger pump is a type of reciprocating positive displacement pump. The plunger pump works in the same way as the piston pump, but instead of a piston moving back and forth, it is a cylinder that makes the fluid moving. How much fluid that is put into motion depends on the size of the plunger. The process is illustrated in Figure 2.14. The seal on a piston pump is kept stationary during operation, while the seal around the piston on a piston pump is moving back and forth with the piston. Because of this, leakages are less likely to occur on a plunger pump than on a piston pump (Michael Smith Engineers, 2020a).

Diaphragm Pump

Another design of a reciprocating positive displacement pump is the diaphragm pump. Instead of a piston or a plunger moving back and forth, the diaphragm pump uses a flexible membrane to enlarge and contract the piston chamber. When the flexible membrane is expanded, fluid is drawn into the chamber. The process is reversed by compressing the flexible membrane, compressing the fluid in the chamber before it is discharged. The process is illustrated in Figure 2.14. According to Michael Smith Engineers (2020a), diaphragm pumps are hermetically sealed which makes them suitable for pumping hazardous fluids.

Gear Pumps

A gear pump is a rotary displacement pump. A gear pump can be either external or internal. On an external gear pump, two interlocking gears are rotating, trapping fluid between the teeths on the gears. As the gears are moving, suction is formed at the pump inlet, forcing the fluid in the pump towards the outlet of the pump where it is discharged. The suction force also prevents fluid from entering the outlet of the pump. An internal gear pump works in a similar way as the external gear pump, but on an internal gear pump two interlocking gears of different size are rotating inside the other. Since the two gears are of different sizes and one rotates inside the other, a cavity is created. As the gears rotates, the cavity between the gears is filled with fluid. The rotation of the gears pushes the enclosed fluid volume towards the pump outlet, where the fluid is discharged (Michael Smith Engineers, 2020a). Figure 2.15 illustrates the process for both external and internal gear pumps.

According to (Michael Smith Engineers, 2020a), gear pumps are suitable for pumping high viscosity liquids. During operation, the gear pump is continuously lubricated by the fluid that is being pumped. Due to this, it is important that the gear pump is not run dry. Also, as the moving components are constantly touching, gear pumps are susceptible

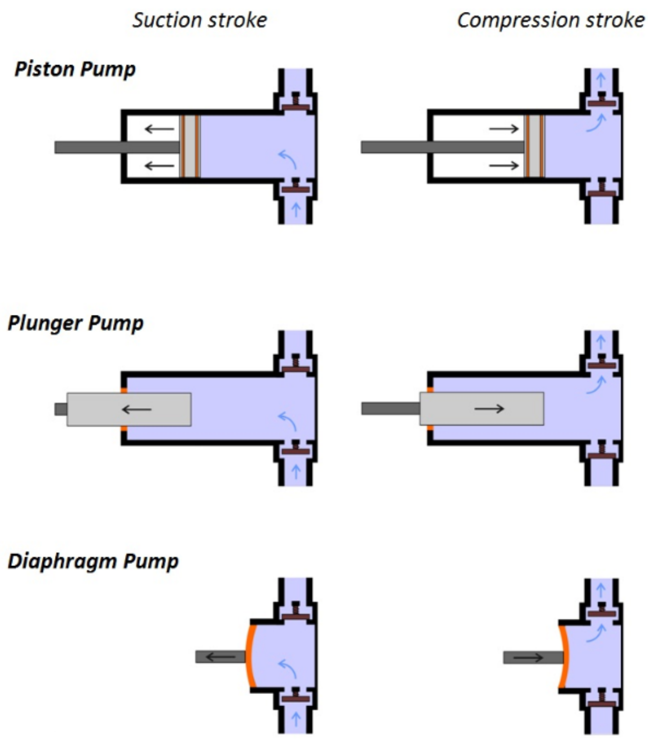


Figure 2.14: The different types of reciprocating pumps (Michael Smith Engineers, 2020a)

to wear. This especially applies when working with abrasive fluids or fluids containing particles (Michael Smith Engineers, 2020a).

Lobe Pumps and Vane Pumps

Lobe and vane pumps are other types of rotary displacement pumps. The lobe pump is similar to the external gear pump, but unlike the external gear pump the two lobes are not in contact with each other. This reduces, according to Michael Smith Engineers (2020a), wear, contamination and fluid shear. In comparison, a vane pump uses a set of movable vanes which is mounted in an off-center rotor. The vanes can be either spring-loaded or flexible. With the rotating center, fluid is trapped in the small chamber created by the vanes which transports fluid from the inlet to the outlet of the pump.

2.9.2 Centrifugal Pumps

Centrifugal pumps are pumps consisting of a rotating impeller placed inside a casing. The impeller has several rotating vanes arranged around a central axis which is driven by a motor. The rotating vanes are setting the fluid into motion, and the velocity and pressure

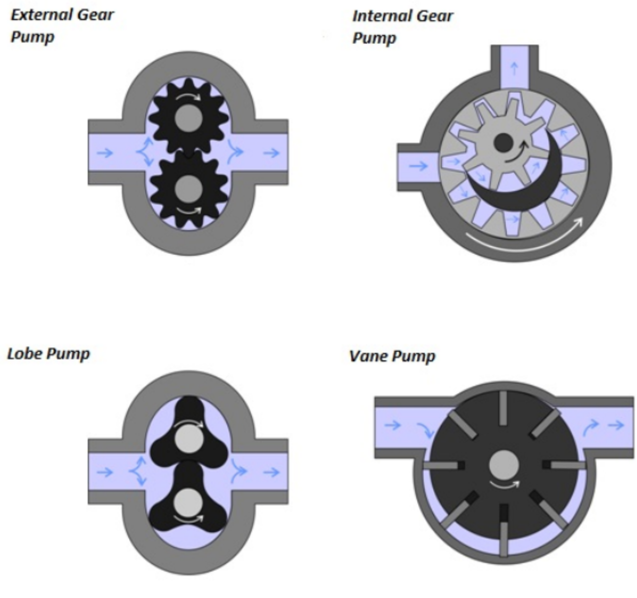


Figure 2.15: The different types of rotary pumps (Michael Smith Engineers, 2020a)

of the fluid increases as it is directed towards the outlet of the pump. The vanes are moving at a typical speed ranging from 500 to 5000 rpm (Michael Smith Engineers, 2020b). Fluid enters at the center of the axes, marked ”Suction Side” on Figure 2.16. At the center, fluid is forced by centrifugal forces along the circumference of the pump and out to the volute chamber before it is discharged at the ”Pressure Side”, see Figure 2.16. Centrifugal pumps are, according to Michael Smith Engineers (2020b), suitable when dealing with large volumes, liquids with low viscosity and low pressures. As the vanes are rotating with such a high speed, the working fluid must not be sensitive to shearing. Another limitation with centrifugal pumps is that they are not able to suction when dry. Since the pumps must initially be primed with the working fluid, the supply must be constant and not intermittent (Michael Smith Engineers, 2020b).

There are two main types of centrifugal pumps: the volute pump and the diffuser pump. A volute pump has an offset impeller, which creates a curved funnel with an increasing cross-sectional area of the volute chamber. The cross-section of the volute chamber increases towards the outlet of the pump, causing the pressure in the fluid to increase towards the outlet of the pump. On the diffuser pump, the vanes of the impeller are stationary. Fluid is expelled between the vanes, increasing the pressure of the fluid. This makes, according to Michael Smith Engineers (2020b), centrifugal pumps with the diffuser design more efficient and the pumps can be tailored for specific applications. The volute design are suitable when dealing with high viscosity fluids and entrained solids (Michael Smith Engineers, 2020b).

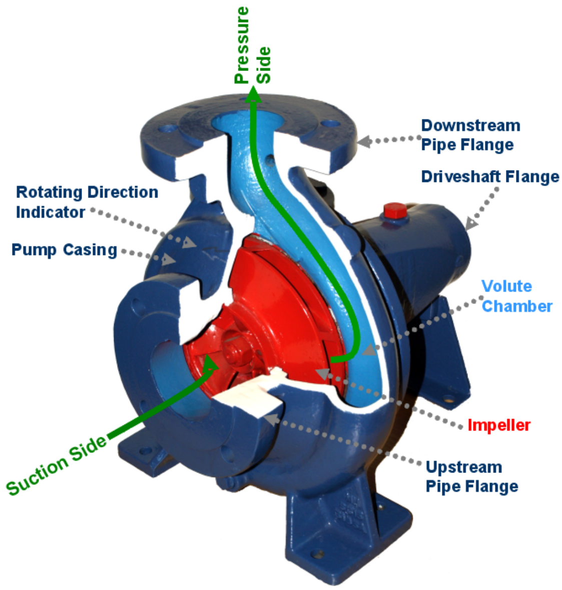


Figure 2.16: A centrifugal pump (Crumpton, 2018)

Table 2.3 summarises the differences between centrifugal and positive displacement pumps. The table was originally made by Michael Smith Engineers (2020b).

Table 2.3: Centrifugal pumps vs. Positive displacement pumps

Property	Centrifugal Pump	Positive Displacement Pump
Effective viscosity range	Efficiency decrease with increasing viscosity (max. 200 Cp)	Efficiency increases with increasing viscosity
Pressure tolerance	Flow varies with changing pressure Efficiency decreases at both higher and lower pressures	Flow insensitive to changing pressure Efficiency increases with increasing pressures
Priming	Required	Not required
Flow (at constant pressure)	Constant	Pulsing
Shearing (separation pf emulsions, slurries, biological fluids, food stuffs)	High speed damages shear-sensitive mediums	Low internal velocity. Ideal for pumping shear sensitive fluids

Chapter 3

Service Line Requirements

As described in Chapter 2.4, the service line enables several tasks to be performed on subsea production and injection wells. These tasks include testing of valves on the Xmas tree, testing the DHSV and controlling pressure changes experienced in Annulus A. The tasks are specified and described in the following sections of this chapter.

3.1 Testing of Valves on the Xmas tree

The service line is frequently used during testing of valves on the Xmas tree. The valves on the Xmas tree are tested in order to verify the integrity of the Xmas tree as a well barrier. Valve testing is performed every month the first three months of operation, and if these tests give acceptable results the interval is extended to every 3rd month. If the results of the tests performed during the first year of production gives good results, the test interval is extended to every 6th month (Alstad, 2011).

Regarding testing of the valves on the Xmas tree, NORSOK D-010 (2004) states the following:

1. The principal valves acting as barriers in the production tree shall be tested at regular intervals.
2. If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed.

When testing a valve on the Xmas tree, the valve being tested is exposed to a differential pressure. The required differential pressure across the valve is 70 bar with 30 bar as a minimum, stated by API RP 14B (2015). If the shut-in tubing pressure is too low to achieve a differential test pressure of 30 bar across the PMV and DHSV, the test should be conducted with the differential pressure available. The differential pressure is required in order to ensure that the gate valves are kept tight, thus verifying the Xmas tree as a well barrier (Equinor, 2018b).

Testing of valves is one of the most dangerous operation the field equipment can be exposed to. According to NORSOK D-010 (2004), “A pressure test intentionally exposes the equipment to a higher stored energy state that it sees in normal field operation to ensure that the design is sound, that materials have no significant flaws and that the equipment has been properly assembled.”

The valves are usually tested in upstream direction, as this is the direction the valve must be able to close in, in case of an emergency situation. However, in some situations the shut-in tubing pressure becomes too low due to low reservoir pressure. This makes it difficult to achieve minimal differential pressure across the valve, thus making it difficult to perform a valid valve test. In this case, an inflow test of the production valves can be conducted, meaning that the valves are being tested in downstream direction. The valve being tested is closed and MEG/methanol is pumped in on the downstream side of the valve by the service line, increasing the pressure above the valve. It the pressure above the valve is kept unchanged for a certain period of time, the test is considered valid (Equinor, 2018b).

A regular valve test of a production valve is initiated by the production being shut down by the choke valve. This is done in order to create stable flow conditions in the Xmas tree before the valve is closed. With stable flow conditions, wear and corrosion of the valves on the Xmas tree are minimized. With the valve being closed, shut-in tubing pressure is working on both sides of the valve. In order to create a differential pressure across the valve, the pressure on the down-stream side of the valve is bled off by the service line. The differential pressure created must remain unchanged for 10 minutes for the valve test to be verified. This is a requirement stated by NORSOK D-010 (2004). A valid test is performed and the results are documented. Before the well can be brought back into production, the differential pressure across the valve must be equalized before the valve is opened. As for when closing the valve, wear and corrosion are minimized if the valve is opened in stable flow conditions. MEG/methanol is injected by the service line into the low-pressure side of the valve, thus equalizing the differential pressure before the valve is opened (Alstad, 2011).

The testing of the annulus valves are performed in the same way as production valves: shut-in pressure works on both side of the valve, the valve is closed and the pressure on one side of the valve is bled off through the service line. However, in some cases the shut-in annulus pressure is too low already at start-up of the well, making it difficult to achieve the necessary differential pressure across the valve during testing. This can be solved by pumping MEG/methanol into the annulus, increasing the pressure on the upstream side of the annulus valve before the valve itself is closed. After the valve is closed, the pressure on the downstream side of the valve is vented to the service line or into the production. After testing, MEG/methanol is pumped into the system in order to equalize the pressure across the valve before the valve is opened.

Testing of the annulus valves can be performed while the well is in operation. However, testing of production valves should not be performed simultaneously as testing of annulus valves, as this may cause unstable temperature conditions in the annulus (Equinor, 2018b).

When performing a valve test, the pressure is expected to develop as illustrated in Figure 3.1. If the curve has a long-term steady rate with sufficient differential pressure across the valve at the same time, the steady rate is measured and utilized (Equinor, 2018b). This may be the case when testing the DHSV. However, if the leakage rate decreases due to reduced differential pressure across the valve, the leakage rate on the first and steepest part of the curve before the curve flattens out due to equalized pressure across the valve, is measured and utilized (Equinor, 2018b). This may be the case when testing small volumes in the production cross and annulus cross on the Xmas tree.

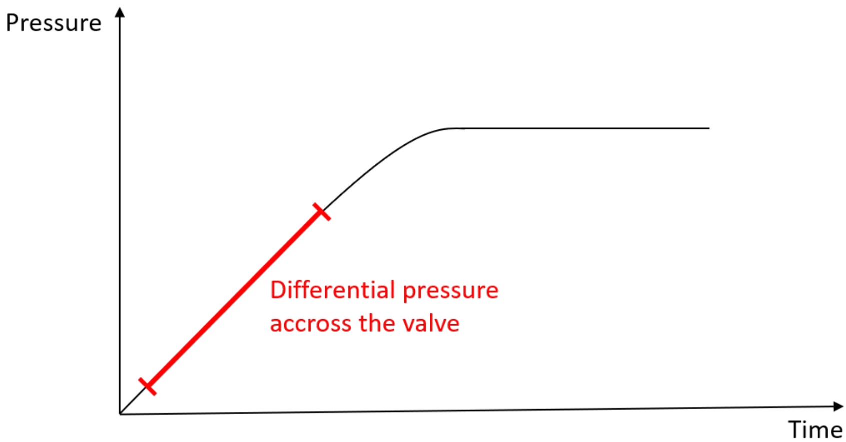


Figure 3.1: Classic pressure curve under testing of valves on the Xmas tree.

Valve testing is usually performed by the Service companies on behalf of the Operating company. Valve testing procedures are different depending on which company who is performing the test. According to Alstad (2011), different test procedures are affected by "specific well conditions, conditions due to different equipment designs, hydrate control and annular fluid."

On producing wells, hydrates may start to form during valve testing, as the system is shut down and thereby cooled by the surroundings. On an injection well on the other hand, the injected fluid holds a lower temperature than the surroundings, and is therefore heated when the well is shut-down. The probability of getting hydrates within the Xmas tree on these wells are lower than on producing wells. However, in order to prevent hydrates to form within the Xmas tree when testing valves on a producing well, MEG/methanol is flushed through the system before valve testing is performed. Hydrocarbons located within the Xmas tree are removed and the system is kept out of hydrate formation conditions during valve testing.

Test procedures for the various valves on the Xmas tree are described in the following sections of this chapter. The testing procedure presented are based on procedures given by Equinor (2018b). The sequence of tests presented below is recommended, but can be done differently if necessary. The test procedures presented are general and do not vary significantly from field to field.

Figure 3.2 shows the various valves on a Xmas tree. Table 3.1 gives the complete name of the various valves.

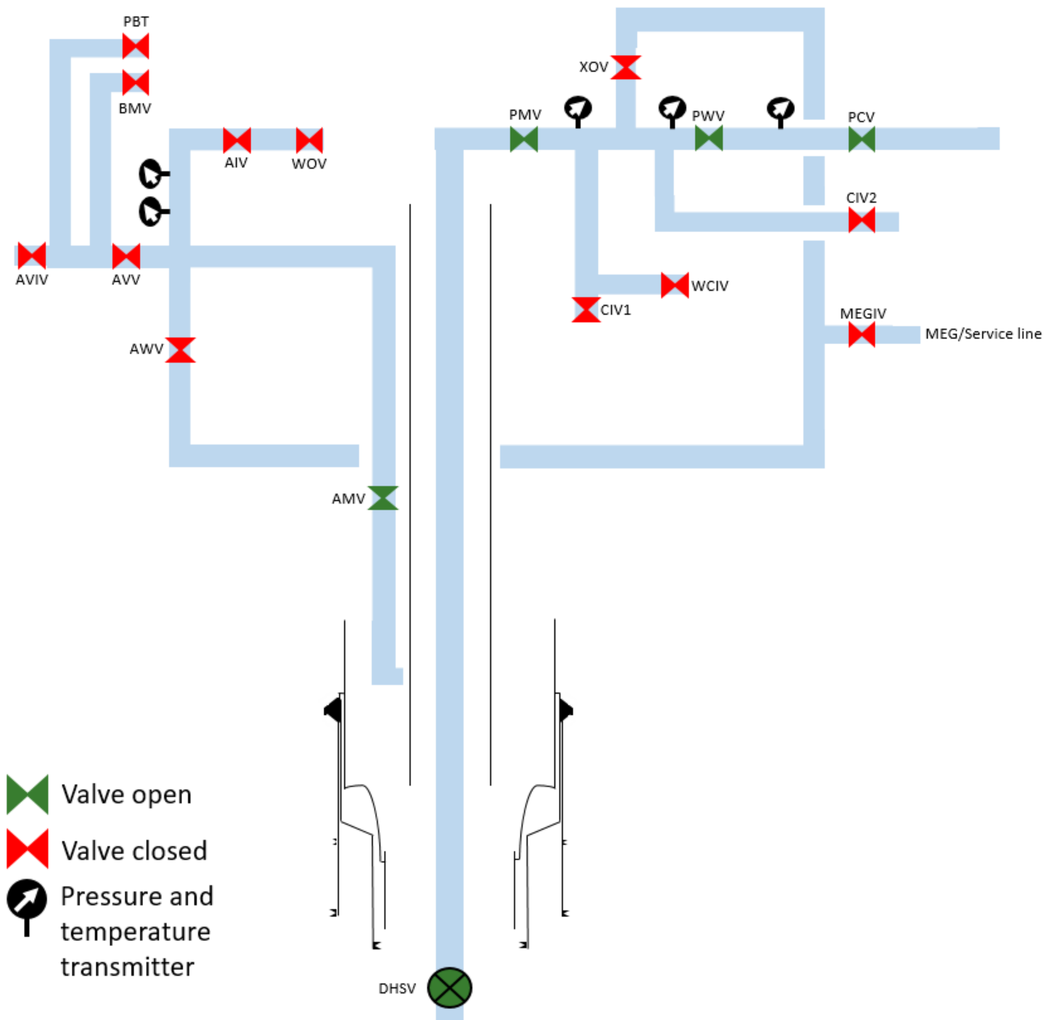


Figure 3.2: Scematic showing the various valves on a Xmas tree. The DHSV, AMV, PMV, PWV and PCV are in open position, and the well is producing.

Table 3.1: Valve Abbrevistions

Abbreviation	Complete name of the valve
AIV	Annulus Isolation Valve
AMV	Annulus Master Valve
AVIV	Annulus Vent Isolation Valve
AVV	Annulus Vent Valve
AWV	Annulus Wing Valve
BMV	Bleed Monitoring Valve
CIV	Chemical Injection Valve
DHSV	Down Hole Safety Valve
MEGIV	MEG Isolation Valve
PBT	Plug Bleed and Test Valve
PCV	Production Choke Valve
PMV	Production Master Valve
PWV	Production Wing Valve
WCIV	Workover Chemical Injection Valve
WOV	Workover Valve
XOV	Crossover Valve

3.1.1 Test Procedure for the Annulus Master Valve

Procedure for testing the AMV is provided below. The presented test procedure is based on the procedures presented by Equinor (2018b). AMV is tested at stable flow and temperature conditions and while the well is producing. The procedure presented is for systems without gas lift.

- Make sure that the shut-in pressure in the annulus is sufficient in order to provide a differential pressure of 70 bar (minimum 30) across AMV. If the pressure in the annulus is too low to create the required differential pressure, annulus can be pressured up by the service line. In that case, the pressure in the annulus must be recorded again.
- Record the shut-in pressure in the annulus.
- Close AMV.
- Open MEGIV and bleed off pressure through the service line in order to achieve a differential pressure across the valve. The pressure can also be bled off into the production line. This is done by opening XOV.
- Close MEGIV or, if utilized, XOV.
- Conduct the test by waiting 10 minutes.
- Document the results.

The scenario where the pressure is bled off through the service line is illustrated in Figure 3.3. AWV is kept open during testing, while AMV, AIV, AVV, MEGIV and XOV are kept closed.

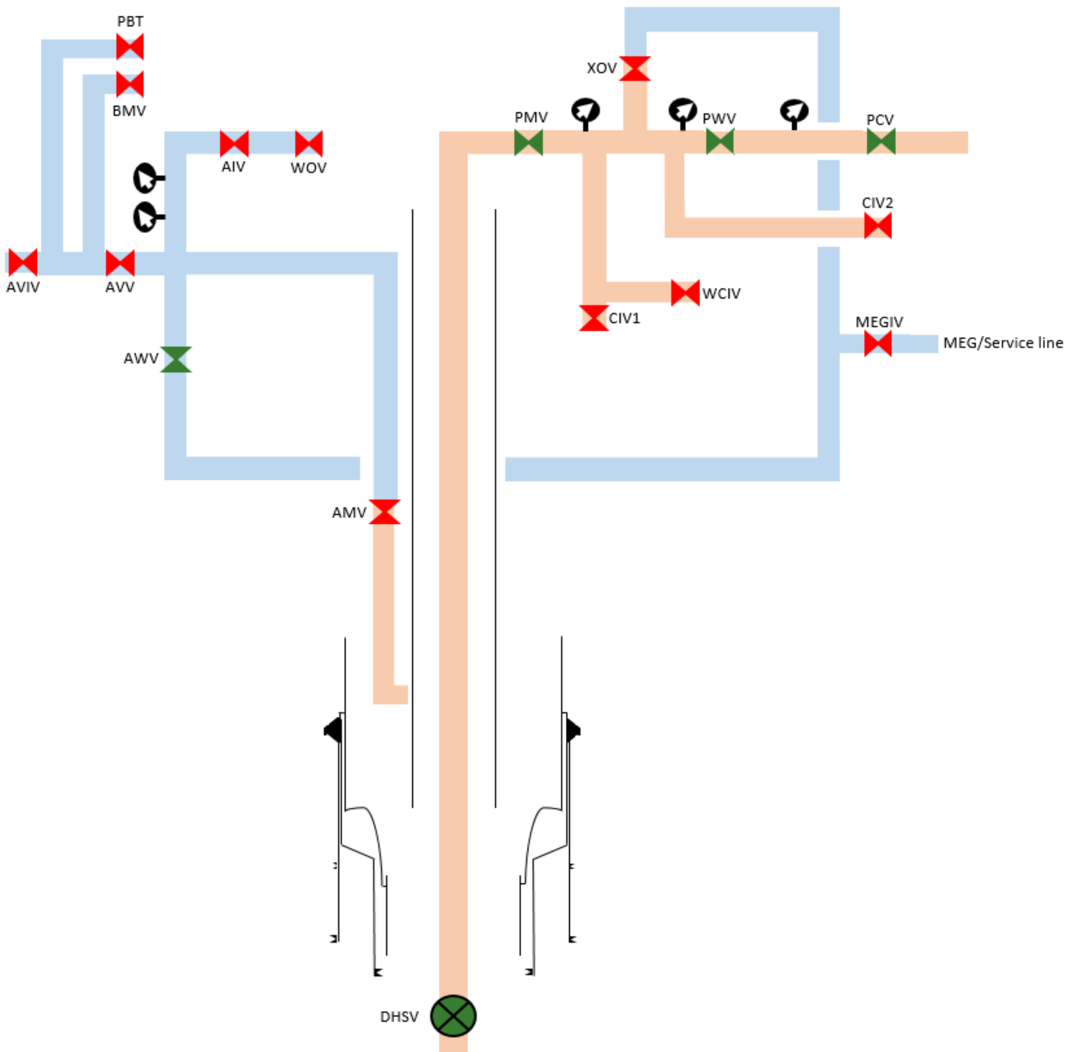


Figure 3.3: Testing scenario for the annular master valve. The well produces while AMV is being tested, and the orange area illustrates the well pressure which is used during testing of the AMV.

3.1.2 Test Procedure for the Annular Cross

Procedure for testing the annular cross is provided below. The annular cross is made up by AVV, AIV, AMV and AWV and is coloured dark blue in Figure 3.4. When the annular cross is tested, AVV, AIV and AWV are tested simultaneously. Should a leakage be detected, the test must be further specified in order to identify whether it is AWV, AVV or AIV that is leaking. The presented test procedure is based on the procedures presented by Equinor (2018b). The valves are tested at stable flow and temperature conditions and while the well is producing. The procedure presented is for systems without gas lift.

- Close AVV, AIV and AMV.
- Pressure up the annular cross with MEG/methanol supplied by the service line.
- Close AWV.
- Bleed off the pressure below AWV through the service line in order to provide a differential pressure of 70 bar (minimum 30) across AWV. The pressure can also be bled off into the production line. This is done by opening XOV.
- Close MEGIV or, if utilized, XOV.
- Conduct the test by waiting 10 minutes. Monitor the pressure.
- Document the results.
- Equalize the pressure across AWV before opening the valve.
- Equalize the pressure across AMV before opening the valve.
- Close AWV.
- If the service line is used to bleed off the pressure below AWV on oil and gas producing wells, hydrocarbons may be located in the service line after testing. Make sure that potential hydrocarbons located in the service line is pumped into the well stream immediately after valve testing has been performed. This is done to prevent hydrates to from within the system.

The test scenario where the pressure is bled off through the service line is illustrated in Figure 3.4.

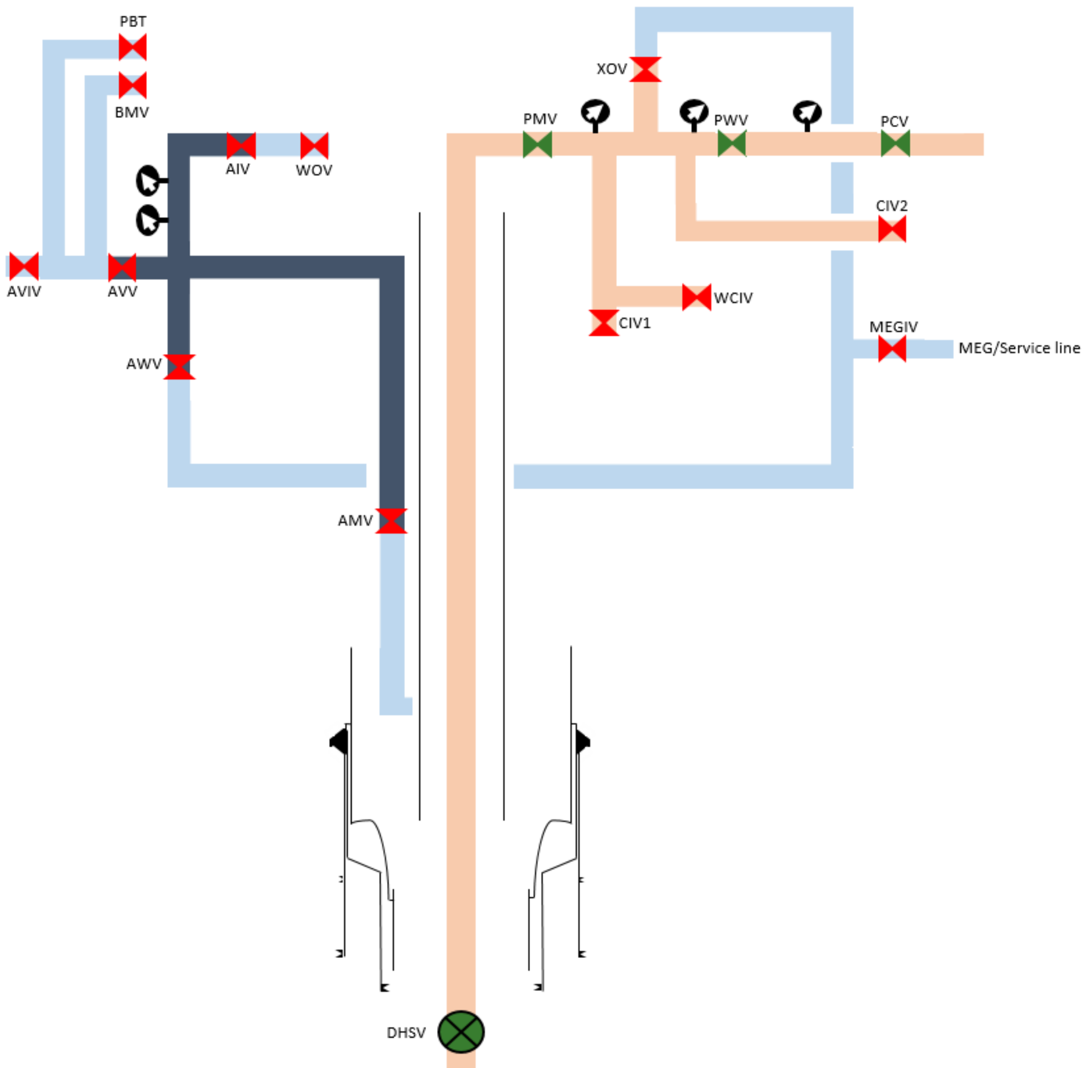


Figure 3.4: Testing scenario for the annular cross. The dark blue area illustrates the enclosed testing volume.

3.1.3 Test Procedure for the Production Cross

Procedure for testing the production cross is provided below. The production cross is made up by PMV, PWV, XOV, CIV1 and CIV2 and is coloured yellow in Figure 3.5. However, testing of the production cross includes testing of PWV, XOV, CIV and CIV2 as there is a separate test procedure for PMV. When testing the production cross, all valves are tested simultaneously. Should a leakage be detected, the test must be further specified in order to identify whether it is PWV, XOV, CIV or CIV2 that is leaking. The presented test procedure is based on the procedures presented by Equinor (2018b). The valves are tested at stable flow and temperature conditions. The procedure presented is for systems without gas lift.

- Stop any possible chemical injection to the well.
- Shut in the well by closing PCV and PWV.
- Wait approximately 15 minutes for the well to stabilize before the annular shut-in pressure is recorded together with the shut-in tubing pressure and the shut-in well temperature.
- Close PMV.
- Verify that AWV is closed and inject MEG/methanol through the service line in order to equalize the pressure across XOV. This must be done with a certain over-pressure in the service line.
- Open XOV and flush the production cross with MEG/methanol supplied by the service line. Continue to pump MEG/methanol into the production cross until the pressure in the cross reaches a differential pressure of 70 bar across PWV.
- Close XOV and bled off the pressure above XOV by opening AWV. The pressure can also be bled off to the service line. Bled off until sufficient differential pressure is achieved, ideally 70 bar with a minimum of 30 bar.
- Close MEGIV
- Monitor the pressure in the production cross for 10 minutes and document the results.

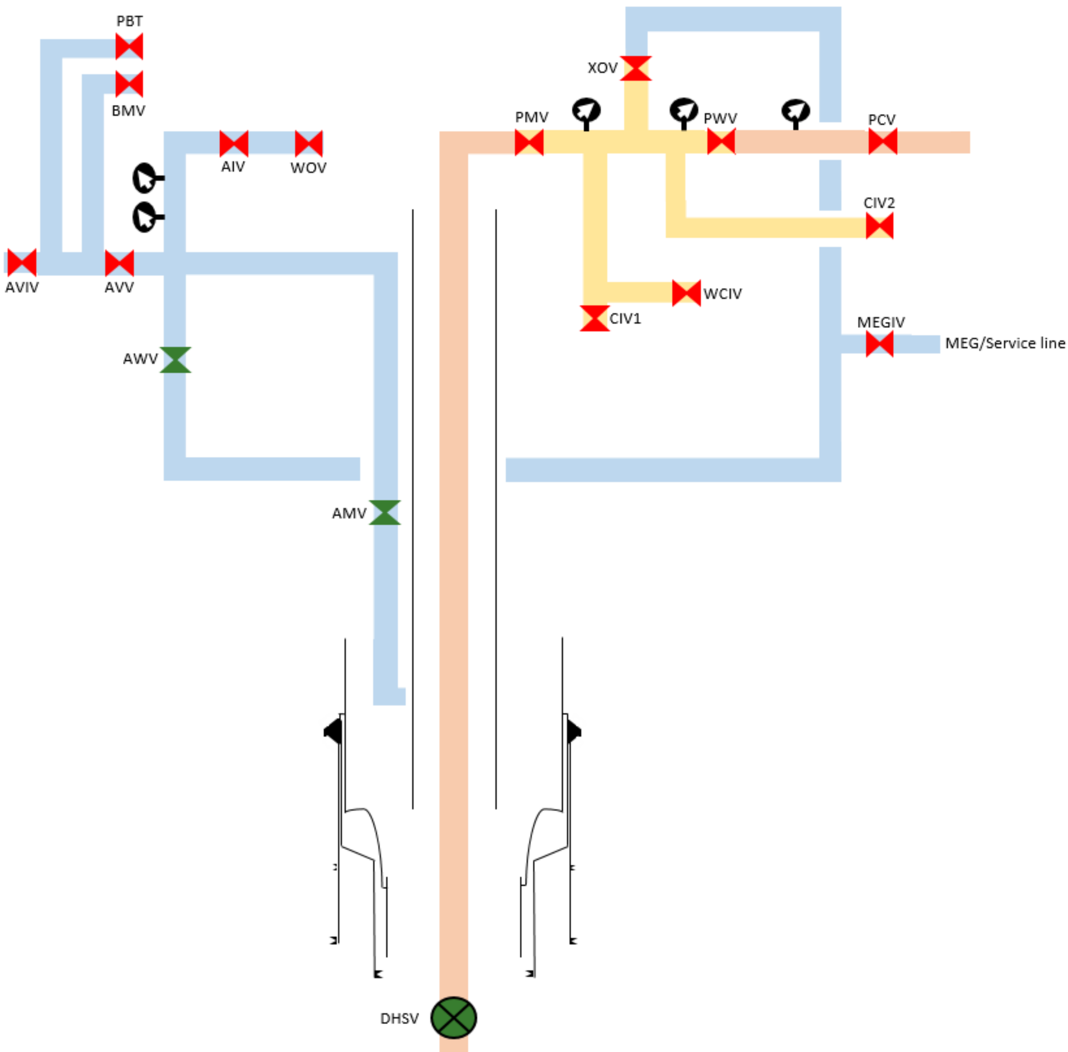


Figure 3.5: An overview of the testing procedure of the production cross. The yellow area shows the enclosed testing volume.

3.1.4 Test Procedure for the Production Master Valve

Procedure for testing the PMV is provided below. The presented test procedure is based on the procedures presented by Equinor (2018b). PMV is tested at stable flow and temperature conditions. The procedure presented is for systems without gas lift.

It is assumed that testing of PMV is conducted after the production cross has been tested. Thus, possible chemical injection to the well is assumed stopped, and PCV, PWV, XOV and PMV are assumed closed.

- In order to establish a differential pressure of 70 bar (minimum 30 bar) across PMV, close AWV
- Open MEGIV
- Inject MEG/methanol through the service line into the system above XOV, so that the pressure across XOV is equalized.
- Open XOV.
- Bleed off the pressure in the production cross via XOV through the service line. Continue until a differential pressure of 70 bar, minimum 30 bar, is achieved across PMV.
- Close XOV.
- Pressure up the differential pressure across XOV to 30 bar.
- Conduct the testing of PMV by waiting 10 minutes. Monitor the pressure.
- Document the results.
- Flush the production cross by MEG/methanol by opening MEGIV and equalize the differential pressure across XOV. Open XOV and start equalizing the pressure across PWV. Open PWV and start flushing the production cross to the production line, via PCV. Close XOV and open PMV.

The test scenario of testing PMV is illustrated in Figure 3.6.

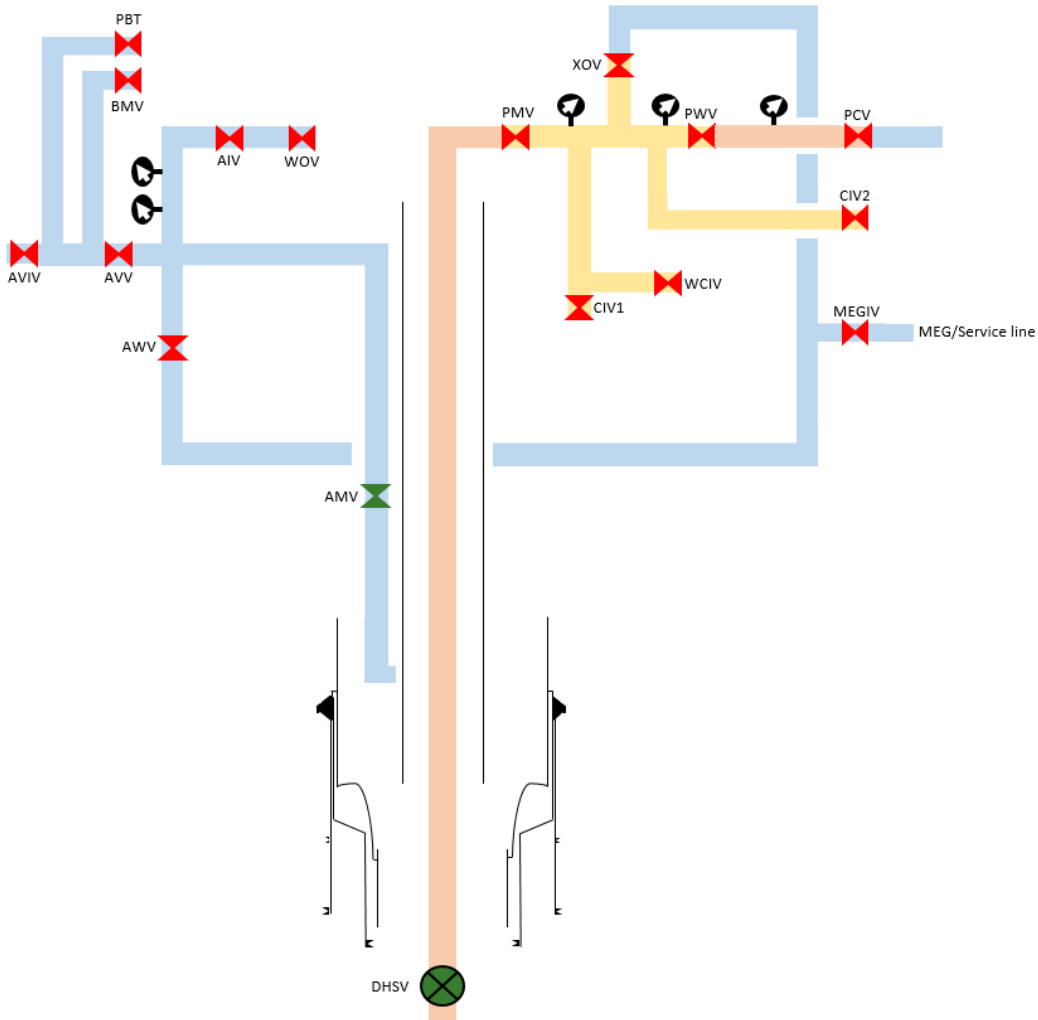


Figure 3.6: Testing scenario for the production master valve. The orange coloured area shows the shut-in tubing pressure, while the yellow coloured area shows the enclosed testing volume. Here, AWV is kept closed during testing in comparison with testing of the production cross where AWV is kept open.

3.2 Testing of the Down Hole Safety Valve

The DHSV is part of the completion string and is considered one of the most important well barrier elements in the well. The DHSV is designed to be failsafe and will isolate the wellbore in case the Xmas tree or wellhead is lost. The valve is a flapper valve and can only be opened in one direction. It is operated by a control panel located at top side. Hydraulic fluid is pumped through a control line which terminates inside the DHSV. The hydraulic fluid builds up a hydraulic pressure enough to force the control sleeve within the valve to move downwards. As the control sleeve is forced downwards, a large spring is compressed, and a flapper is pushed forward, thus opening the valve. When the applied pressure is released, the spring pushes the control sleeve back and causes the flapper to shut and the valve closes (Sangesland et al., 2012). The open and close mechanism is illustrated in Figure 3.7.

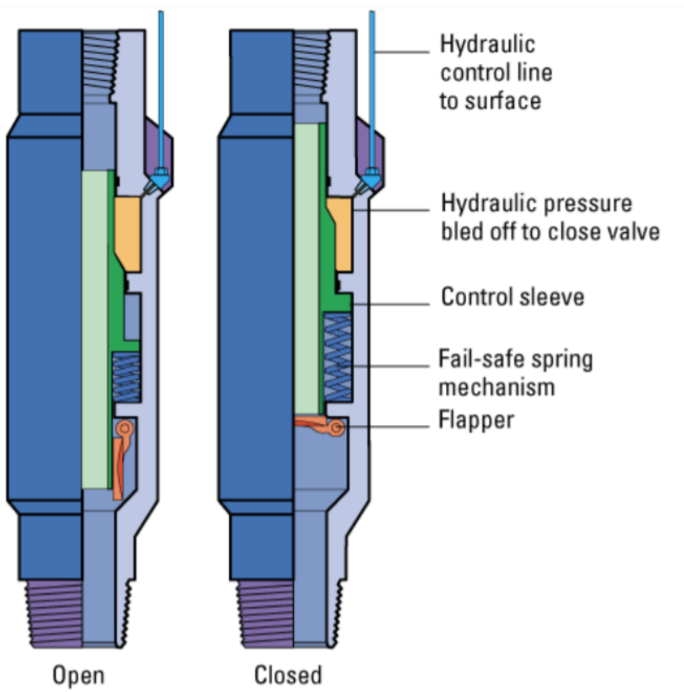


Figure 3.7: "Schematic of a Downhole Safety Valve (DHSV) in open and closed position" (Sangesland et al., 2012).

3.2.1 Setting Depth of the DHSV

The positioning of the DHSV is an important parameter in the subsea design. The positioning of the valve determines the volume of fluid that can accumulate above the valve after it is closed. The further down the valve is positioned, the more fluid can accumulate above the valve. By placing the valve further up in the well, the accumulated volume of hydrocarbons is confined, thereby confining the hazard in a possible emergency or spill situation. In addition, the lower down the DHSV is placed, the more hydraulic fluid is required to keep the valve in open position. It is important that the valve is placed at a certain position so that the pressure created by the hydraulic fluid is kept below the pressure needed to keep the valve in open position. If the hydraulic pressure caused by the hydraulic fluid exceeds the pressure needed to keep the valve open, the valve would remain open even with loss of surface pressurisation. In this scenario, it would not be possible to close the valve, meaning that a well barrier is lost. According to Sangesland et al. (2012), the DHSV is usually placed in the completion between 100m and 500m below the seabed.

API RP 14B (2015) states the following requirements concerning determination of SCSSV setting depth:

1. actuation method;
2. communication system capabilities and limits;
3. maximum fail-safe setting depth according to the supplier/manufacturer's operating manual;
4. gradient and pressure of the annulus and control line fluids;
5. SSSV closing and opening pressure from the shipping report;
6. required design margins;
7. anticipated pressures (absolute and differential) and temperature ranges at valve depth;
8. paraffin, hydrate depostion, asphaltenesl, pour point of well bore fluid, etc.
9. well construction design such as wet or dry tree, permafrost, proximity to adjacent wells, etc.

3.2.2 Testing Intervals for the DHSV

The DHSV is part of the wells safeguarding system and can isolate the reservoir fluid from the surface if necessary. Failure of such safeguarding systems may not be noticeable before the system is needed and it is therefore important to check the functionality of the system at defined intervals throughout the lifetime of the well. API RP 14B (2015) recommends testing of the barrier system "every six months unless local regulations, conditions and/or documented historical data indicate a different testing frequency". API RP 14B (2015) also states that checking and testing should be carried out during:

- "normal operations, using maintenance override switches; shutdown valves should not be actuated during normal operations"
- "scheduled shutdowns, which could be initiated by actuating an individual shutdown device to test the system as a whole"

- "unscheduled shutdowns initiated by any other causes."

As for the other valves on the Xmas tree, a differential pressure of 70 bar is required across the DHSV when testing is conducted. However, as the shut-in tubing pressure decreases with increasing production time of the well, it can be difficult to achieve the required differential pressure across the valve after the well has been producing for a while. There are also limitations concerning how much pressure that can be bled off through the service line. In such situations, one must test with the differential pressure available (Equinor, 2018b).

3.2.3 Testing Procedure for the DHSV

API RP 14B (2015) specifies the following steps in the test procedure for installed DHSVs. Figure 3.8 illustrates the testing procedure for the DHSV.

1. Record the control pressure in the DHSV control line.
2. Isolate the control system from the well to be tested.
3. Shut down the production by closing PCV.
4. Wait a minimum of 5 min or the duration required in order to establish a stable fluid phase in the well. Record the shut-in tubing pressure.
5. Isolate the control line pressure source from the DHSV control line. Observe the pressure within the DHSV control line. If pressure changes are observed, investigate, record, and take corrective action as necessary. It is important to identify any leakage in the DHSV control line before testing of DHSV is performed. Thus, if a leakage is identified during testing of the DHSV, it is for certain that it is DHSV that is leaking and not the control line connected to it.
6. Locate, identify, measure, and consider any leakage of the PWV, XOV and MEGIV, before testing the DHSV. It is important to identify any leakage in the adjacent valves before testing the DHSV, so that if a leakage is identified during testing of the DHSV, it is for certain that it is DHSV itself that is leaking and not the any of the other valves on the Xmas tree.
7. Close DHSV.
8. Close PWV.
9. Bleed off the pressure between PWV and DHSV via XOV as much as possible in order to create a differential pressure across DHSV. The pressure below the DHSV is now the shut-in tubing pressure while the pressure above the valve is the lowest practical pressure vented to the manifold.
10. Close XOV to enclose the testing volume.
11. Conduct the valve test and document the results.

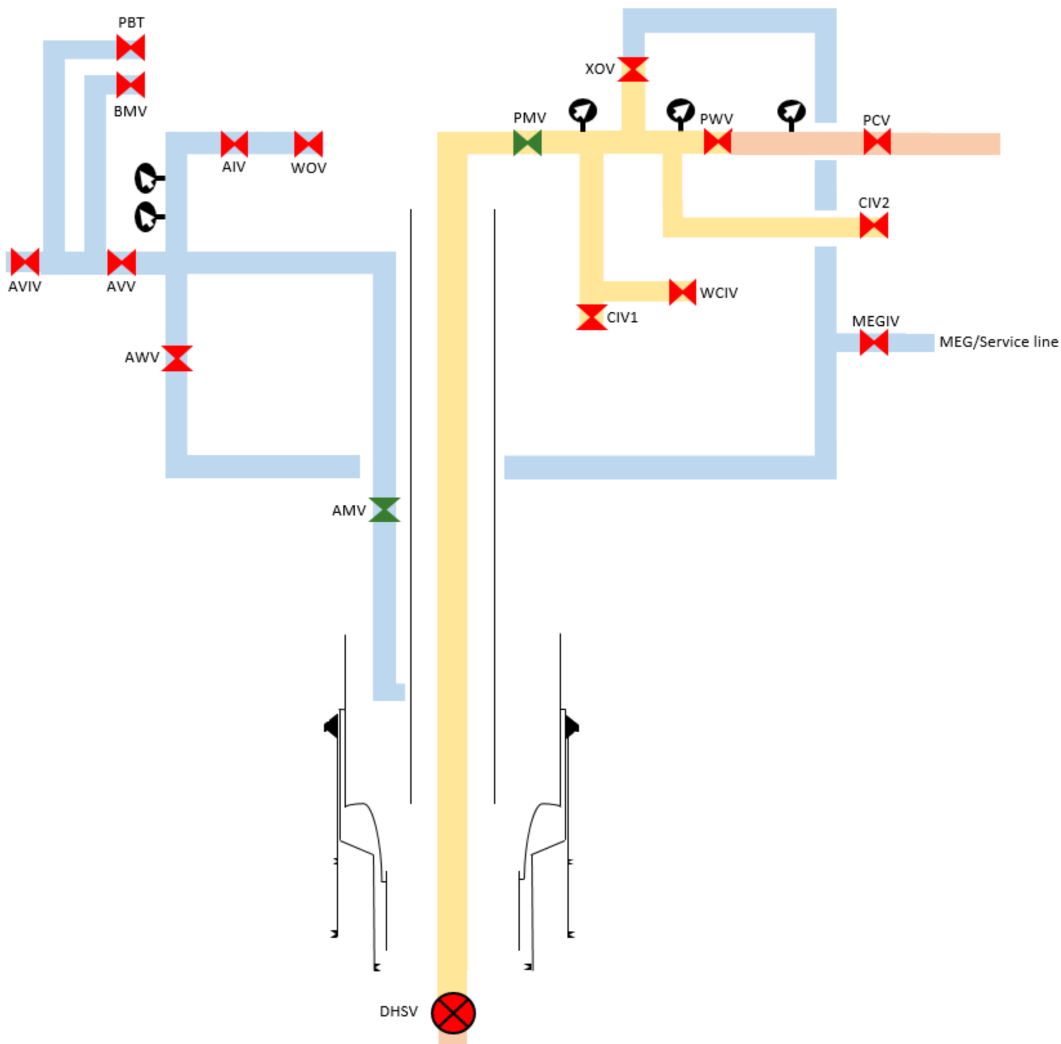


Figure 3.8: An overview of the testing procedure of the DHSV. The orange area shows the shut-in tubing pressure, while the yellow area shows the enclosed testing volume.

The acceptable leakage rate for the DHSV is defined by API RP 14B (2015) as:

- 0.422 Smm3/min for gas
- 0.4 l/min for liquid

If the valve fail to close or if the leakage rate exceeds the acceptable leakage rates, the well shall remain shut-in until one of the following corrective actions has been performed (API RP 14B, 2015):

1. “remediate, repair, or replace the SSSV to conform to the acceptance criteria”
2. “complete an approved documented risk assessment for continuing operations”

After the DHSV has been tested, the valve must be opened and the well must be brought back into production. It is during the re-opening of the DHSV that the need for the service line appears. After the DHSV has been tested, the differential pressure created across the valve during testing must be equalized before the valve is opened. This is done, as for the other valves on the Xmas tree, to reduce wear and corrosion of the valve. The XOV is opened and MEG/methnaol is injected into the system through the service line in order to equalize the differential pressure across the DHSV. The volume of MEG/methanol required is determined by the setting depth of the DHSV. After the differential pressure has been equalized, the valve can be opened and production can continue (Equinor, 2018b).

3.3 Control of Annulus Pressure

Annulus A is the designation of the space between the production tubing and production casing. This is an enclosed system filled with fluid. The pressure in annulus A is determined by the well temperature, the temperature and pressure in the adjacent annuli and the flow rate. When the well produces at a steady rate, the pressure in Annulus A is also expected to remain stable (Brechan et al., 2017).

On oil and gas producing wells, the produced fluid will hold a higher temperature than the surroundings. At start-up of a well, the packer fluid in Annulus A will be heated by the high tempered production stream. As the packer fluid is heated up, the fluid will start to expand which will increase the pressure within the annulus. In addition, when a producing well is shut down, the supply of high tempered fluid stops. The fluid located in the production sting at shut-down will be cooled by the surroundings, and the packer fluid within Annulus A will be cooled accordingly. As a result, the volume of the packer fluid within the annulus begins to contract.

On water and CO_2 injecting wells, the injecting fluid will hold a lower temperature than the surroundings. Thus, at start-up of the well, the packer fluid in Annulus A will be cooled by the injected fluid and the volume of the packer fluid will start to contract accordingly. As for producing wells, during shut down of a water or CO_2 injecting well, the supply of cold injection fluids stops. The fluid located in the injection string at shut-down will be heated by the surrounding, and the packer fluid in Annulus A will be heated accordingly.

As a result, the volume of the packer fluid within the annulus begins to expand.

The pressure differences experienced in Annulus A may be big and applies for both producing and injecting wells. When pressure changes are experienced within the annulus it is necessary to equalize the pressure. This is on today's subsea system performed by the service line. When the pressure within Annulus A becomes too low, MEG/methanol is pumped into the annulus by the service line. MEG/methanol is injected until the pressure within the annulus is equalized (Brechan et al., 2017).

When the pressure within Annulus A becomes too high, the pressure can be bled off to the service line, via the XOV to the production line or by the annulus monitoring line (API RP 14B, 2015). If a well is equipped with a XOV, the encountred volume within Annulus A should, according to API RP 14B (2015), be bled off through this. The pressure is then bled off to the production stream into the flowline. By doing so, the service line in the umbilical is protected from potential damage. If the well is installed without a XOV, the pressure can be bled off through the Annulus monitoring line. However, according to API RP 14B (2015), "bleeding off pressure through this line should only be done when absolutely necessary because of the potential for plugging of the line with emulsions, paraffin or hydrates."

According to Brechan et al. (2017), the packer fluid located in Annulus A is often brine. As described above, the packer fluid will expand/contract in response to temperature changes experienced in the annulus. Figure 3.9 shows how the density of fresh water changes with variations in pressure and temperature in an enclosed system. Brine has many of the same properties as fresh water. Thus, pressure changes experienced in a brine containing annulus will be of a similar character to that illustrated in Figure 3.9.

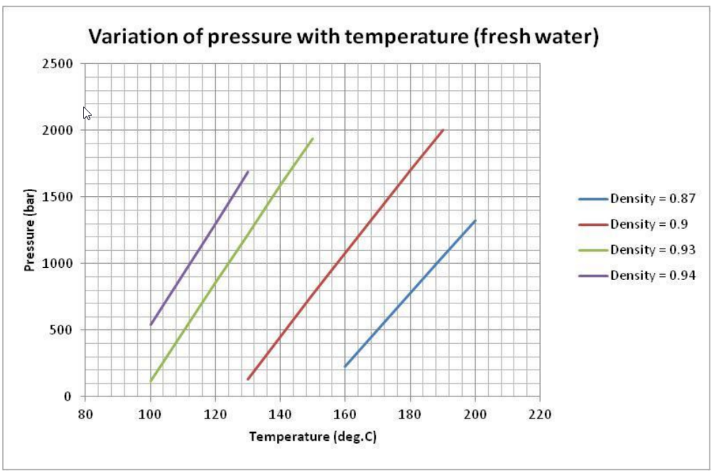


Figure 3.9: "Variation of pressure with temperature for fresh water in an enclosed system." (Sangesland et al., 2012)

The thermal expansion and contraction experienced in Annulus A can lead to severe damage on the adjacent casings. As the temperature changes, the casing and the tubing that makes up the annulus will experience a change in length. Heated metal expands, and cooled metal contracts. In a long string of casing with a temperature change over its entire length, it's contraction or elongation can be considerable. However, studies performed by Equinor shows that the elongation and contraction of the adjacent casings are insignificant during start-up and shut-in of a producing well. This will therefore be neglected in this thesis.

Annulus A makes up an enclosed system. If the pressure changes experienced in Annulus A is not equalized, the packer fluid within the annulus will not be able to expand or shrink. Thus, if the annulus is not vented or refilled when necessary, the nearby casing and tubing may be damaged. The casing and tubing making up the annulus may as a result burst or collapse, which could potentially lead to a loss of well integrity (Sangesland et al., 2012).

Chapter 4

Solutions

As described in the previous chapter, the service line enables various functions to be performed on subsea production and injection wells. The service line is used to achieve sufficient test pressure across a valve during testing of valves on the Xmas tree and the DHSV. The service line enables testing of valves when the shut-in pressure becomes too low. Also, after testing, MEG/methanol is pumped in on the low-pressure side of the valve to equalize the pressure before the valve is opened so that wear and corrosion of the valve is minimized. In addition, the service line is used to control pressure changes experienced in Annulus A.

MEG/methanol is also supplied to the field in order to prevent hydrates to form within the subsea system. Hydrates are considered an issue on both production and injection wells. As gas is present on producing wells and on wells injecting CO_2, hydrates can form during operation. Water injection wells may experience gas migration into the Xmas tree when the well is put out of operation for a period of time. Thus, hydrates can form within the Xmas tree on water injection wells too.

As previously described, it is of interest to remove the service line so that an all-electric subsea field can be operated by a DC/FO cable alone. Since producing wells face different challenges than injection wells, different solutions for the different well types are needed for the service line to be removed. The various challenges faced on oil and gas producing wells and water and CO_2 injection wells are further described and specified in the following section of this chapter. Solutions overcoming these challenges, thus making it possible to remove the service line are also presented.

4.1 Oil Producing Wells

The service line enables several functions to be performed on oil producing wells. As previously described, the service line is used during valve tesing of the Xmas tree and DHSV and to control pressure in Annulus A. In addition, MEG/methanol is supplied to the well by the service line in order to prevent hydrates from forming within the subsea system. MEG/methanol does also protect the inside of the Xmas tree from corrosion. Hydrates are considered an issue on oil producing wells. As described in Chapter 2.6.1, hydrates are formed when gas molecules are combined with salt under certain pressure and temperature condition. Since many oil producing wells also produce associated gas, gas molecules may easily be located inside the Xmas tree during operation. In that case, all hydrate formation conditions are achieved and hydrates can begin to form within the system.

It is of interest to remove the service line from the umbilical on oil producing wells. In order to do so, the functions provided by the service line must be performed in a different way than how it is done with today's subsea system. An important function enabled by the service line is the creation of sufficient test pressure across the valve during testing of the Xmas tree. Valve testing are performed in specified intervals throughout the lifetime of the well. With today's solution with a service line, a test fluid is required in order to perform valve testing. If the service line is removed from the umbilical, another test fluid must be supplied to the system so that the mandatory procedures can continue to be performed.

Using seawater as test fluid is a possible solution for the service line to be removed on oil producing wells. Seawater is highly available as the subsea system is submerged in seawater. Also, seawater is gratis, which will be a clear advantage with the solution. Another advantage is that after seawater has been used during valve testing, seawater can be dumped directly to sea without further treatment. Today, used test fluid is vented to the service line or to the production line.

There are several challenges associated with pumping seawater into the subsea system. A challenge is to combine salt-containing water and gas under certain temperature and pressure conditions, as this will lead to hydrate formation within the system. Since oil producing wells often produce associated gas too, gas molecules will be located in the Xmas tree, and thus achieving all hydrate formation conditions. Another challenge is that seawater contains various salts, minerals and other substances. By using seawater as test fluid, these salts are combined with hydrocarbons from the producing well, increasing the possibility of hydrate formation. However, many oil and gas producing wells produce formation water simultaneously. Neff et al. (2011) defines formation water as "seawater or fresh water that has been trapped for millions of years with oil and natural gas in a geologic reservoir consisting of a porous sedimentary rock formation between layers of impermeable rock within the earth's crust." The ratio of produced water increases as the reservoir matures, and it often exceeds the ratio of produced hydrocarbons during the reservoir depletion phase.

According to Neff et al. (2011), the salinity of produced water ranges from a few part per thousand (‰) to around 300 ‰. The salinity of saturated brine and seawater is 300 ‰and

32 ‰- 36 ‰accordingly (Neff et al., 2011). This means that the salinity of produced water is usually higher than the salinity of seawater. According to Neff et al. (2011), produced water contains many of the same salts as seawater, such as sodium, chloride, calcium, magnesium, potassium, sulfate, bromide, bicarbonate, and iodide. However, as the concentration of many of these salts are higher in produced water than in seawater, produced water is considered aquatic toxic (Neff et al., 2011).

If seawater is used as test fluid on oil producing wells, the probability of hydrate formation is greater than when using conventional test fluids, such as MEG or methanol. The combination of formation water and seawater results in another challenge too. The combination significantly increases the probability of salt precipitation. Formation water is often over-saturated with various types of salts capable of forming heavy salts, which will precipitate and form scale (Equinor, 2019d). Scale can lead to plugging of perforations, valves, pumps and completion equipment. Scale can be treated mechanically or by inhibition. If an inhibition fluid must be supplied to the subsea development to treat scale related problems, the motivation removing the service line in the first place is gone.

As the possibility of both hydrate and scale formation is increased by using seawater as test fluid on oil producing wells, pumping seawater into the Xmas tree is considered challenging on oil producing wells. A solution that could enable the use of seawater as test fluid is to heat up the vulnerable areas on the Xmas tree. By doing so, one of the conditions necessary for hydrates to form is removed. The heating could be performed by heaters similar to what is installed in regular vehicles. For developments with long tie-back lengths this could be a cost saving solution. A cost analysis will be necessary to investigate whether this is a possible solution for oil producing wells.

If seawater is excluded as a potential test fluid, other solutions that allow operation of the subsea field without a service line must be considered. As MEG or methanol adds a higher degree of safety to the subsea development, it will be difficult to remove the supply of these chemicals completely. However, these test fluids can be supplied to the field in a different way than through the service line. As described in Chapter 2.7, required chemicals can be stored in subsea tanks located close to the wellsite. With this solution, MEG/methanol can be stored in similar tanks and be supplied to the well when necessary. This would enable the service line to be removed on an oil producing well.

If MEG or methanol is to be stored in a subsea tank located close to the wellsite, such a tank must be designed. In order to design the tank in correct dimensions, the volume of MEG/methanol required when performing the various tasks must be identified. The dimensions of the subsea tank are determined by the following:

- The required volume of test fluid needed when equalizing the pressure across DHSV.
- The required volume of test fluid needed during valve testing.
- The required volume of test fluid needed when controlling pressure changes experienced in Annulus A.

The listed volumes are calculated in the following sections of this chapter.

4.1.1 Volume of Test Fluid required when Equalizing Pressure Across the DHSV

As described in Chapter 3.2, the test pressure across the DHSV must be equalized before the valve is opened after it has been tested. This is done by pumping MEG or methanol through the service line into the tubing string above the DHSV until the shut-in tubing pressure is reached. After the pressure across the valve has been equalized, the DHSV can be opened.

Most oil producing wells are equipped with a completion of 7 inches (0.1778 m^2) or smaller, with an inner diameter of 6 inches (0.1524 m^2). When closing the DHSV, the tubing string above the valve is filled with hydrocarbons. This is the initial volume in the tubing string, denoted V_i. Equation 4.1 is used to calculate the initial volume of hydrocarbons located in the tubing sting above the DHSV prior to testing. The initial volume of hydrocarbons in the tubing string will vary with varying setting depth of the DHSV. According to Sangesland et al. (2012), the setting depth of the DHSV ranges from 100m to 500m below seabed. The volume of hydrocarbons located in a tubing string with inner diameter of 6", with respect to varying setting depths of the DHSV, is illustrated in Figure 4.1 and 4.2.

$$V_i = \frac{\pi}{4} * d^2 * h \tag{4.1}$$

$$V_i = \frac{\pi}{4} * 0.1524m^2 * h \tag{4.2}$$

In order to equalize the differential pressure across the DHSV after it has been tested, the hydrocarbons located above the valve must be compressed. This is done by pumping test fluid, MEG or methanol, into the tubing string above the valve until the shut-in tubing pressure is reached. Equation 4.3 is used to calculate the volume of test fluid required in order to equalize the differential pressure across the DHSV.

$$V = \frac{\Delta V}{\Delta P} * K \tag{4.3}$$

$$V = \frac{V - V_i}{\Delta P} * K \tag{4.4}$$

Where

$V =$ The volume of fluid in the tubing string above the DHSV in m^3 (litres) during pressure equalizing;

$V_i =$ The initial volume of hydrocarbons in the tubing string above the DHSV in m^3 (litres);

$\Delta P =$ The required differential pressure across the DHSV during testing, bar;

$K =$ The bulk modulus of the fluid in the tubing string above the DHSV, bar;

According to Mougin et al. (2002), the bulk modulus for different types of oil varies from 1.1 GPa and 3.2 GPa, equivalent to 11 000 bar and 32 000 bar. The volume of test fluid needed will vary with respect to the setting depth of the valve and the bulk modulus of the

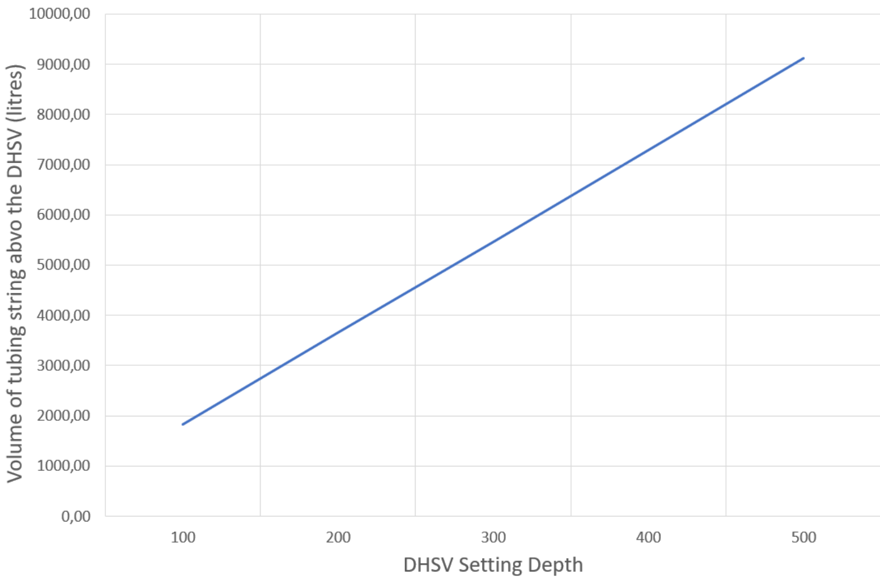


Figure 4.1: Volume in the tubing string above the DHSV, in litres, with respect to varying setting depths of the DHSV.

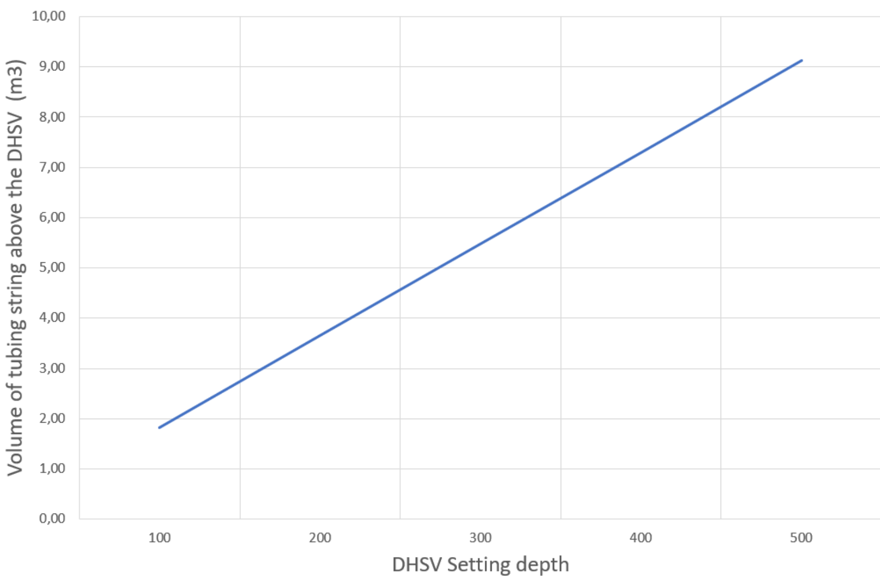


Figure 4.2: Volume in the tubing string above the DHSV, in m^3, with respect to varying setting depths of the DHSV.

test fluid. The variation of required volume with respect to these two parameters is shown in Figure 4.3 and 4.4.

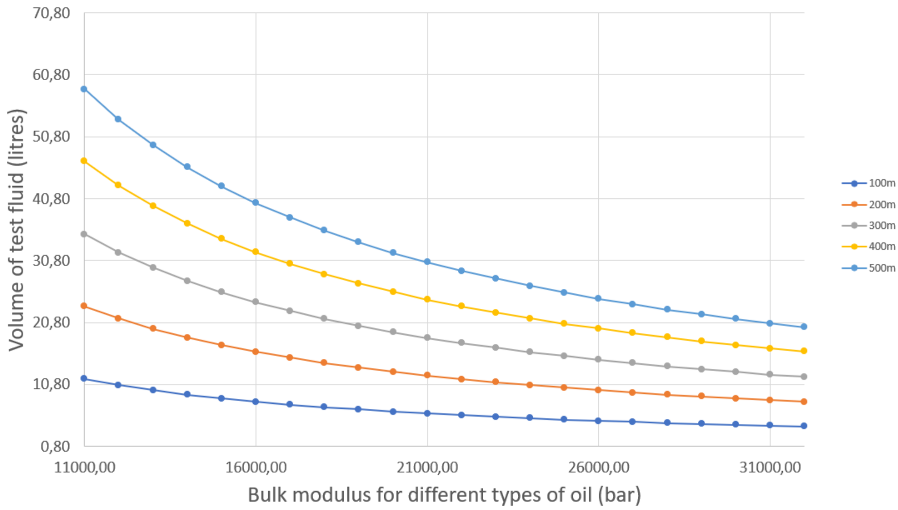


Figure 4.3: The volume of test fluid, in litres, with varying DHSV setting depths and bulk modulus for different types of oil.

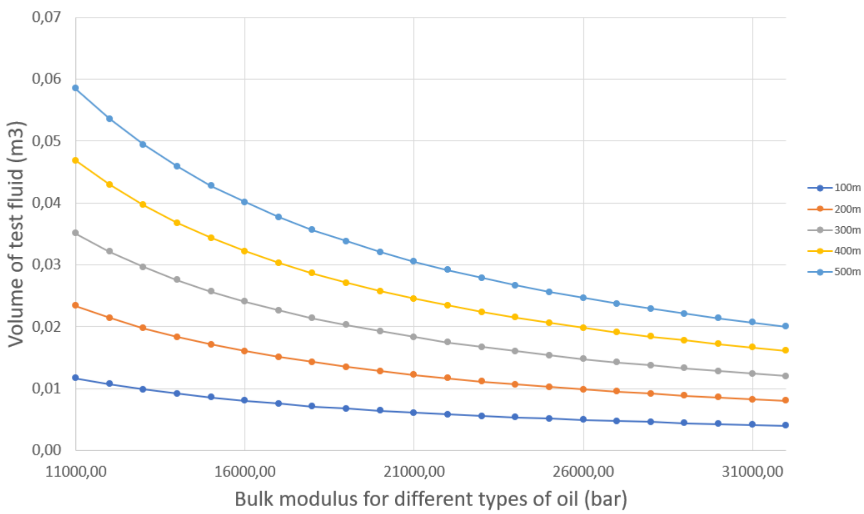


Figure 4.4: The volume of test fluid, in m^3, with varying DHSV setting depths and bulk modulus for different types of oil.

As shown in Figure 4.3 and 4.4, the biggest required volume of test fluid is when the setting depth of the DHSV is at 500m and when the bulk modulus of oil is 11 000 bar. Under these conditions, a volume of 58.45 litres, equivalent to 0.06 m^3, of test fluid is required in order to equalize the shut-in tubing pressure. The volume is used in later calculations related to the design of the subsea tank.

4.1.2 Volume of Test Fluid required during Valve Testing on the Xmas Tree

As described in Chapter 3.1, test fluid is pumped through the service line into the area where valves are to be tested. Pressure builds up on the upstream side of the valve before the valve is closed. After the valve is closed, the service line is used to bled off the pressure downstream of the valve, creating a differential pressure of about 70 bar if possible.

The volume of test fluid required to fill the system will vary depending on the valve being tested. However, the volume of test fluid required during testing of the valves on the Xmas tree will not be the volume that dimensions the subsea tank on oil producing wells. It is therefor assumed that a volume equivalent to filling a 6 inch wing bore, with a length ranging from 0.5 m to 2 m, is an adequate estimate of the volume required during valve testing on the Xmas tree. It is further assumed that the inner diameter of the wing bore inside the Xmas tree has the same inner diameter as the tubing string above the DHSV, with an inner diameter of 6 inches (0.1524 m^2).

Since the Xmas tree contains several valves, the calculated volume must be multiplied by how many times MEG/methanol is to be filled into the system when all the valves on the Xmas tree are tested. According to Equinor (2018b), this is done a total of six times:

- When testing the AMV
- When testing AVV, AWV and AIV
- When testing PWV and XOV
- When testing PMV
- The production cross is flushed with MEG/methanol twice to avoid hydrate formation during valve testing. This is done before testing the PWV and XOV, and when testing the PMV.

Equation 4.1 is used to calculate the initial volume of hydrocarbons in the system prior to testing while Equation 4.3 is used to calculate the required volume of test fluid needed to compress the hydrocarbons located in the system in order to build up sufficient test pressure across the valve. The result is shown in Figure 4.5 and Figure 4.6. According to ToolBox (2003b), the bulk modulus for several common fluids ranges from 1.1 GPA to 3.2 GPa, corresponding to 11,000 bar and 32,000 bar, which are used in the following calculations.

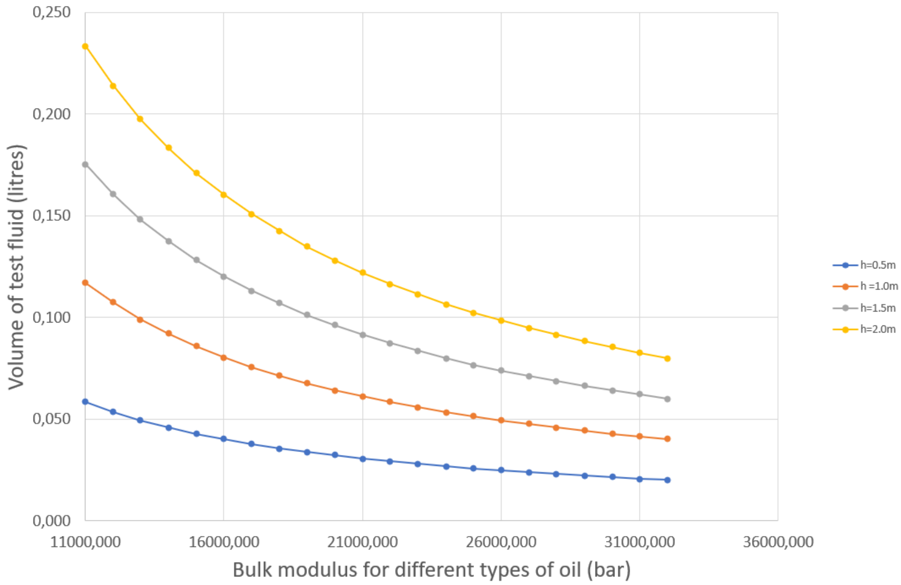


Figure 4.5: The required volume of test fluid, in litres, with varying wing bore lengths and bulk modulus for different types of oil.

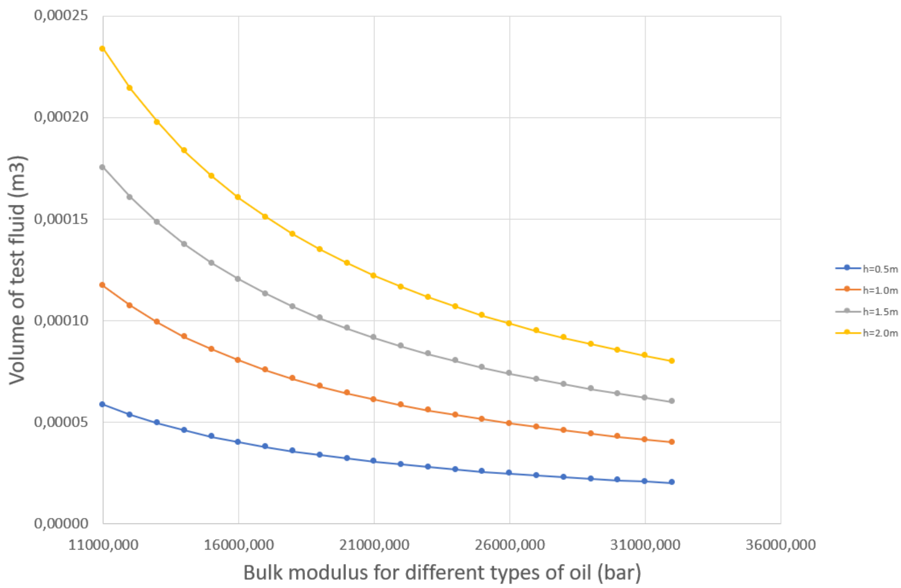


Figure 4.6: The required volume of test fluid, in m^3, with varying wing bore lengths and bulk modulus for different types of oil.

As shown in Figure 4.5 and Figure 4.6, the largest volume of test fluid is required when the length of the wing bore is assumed to be 2m and when the bulk modulus of oil is assumed to be 11 000 bar. Under these conditions, a volume of 0.2337 litres, equivalent to 0.0002 m^3, of test fluid is required when testing a valve on the Xmas tree. Thus, a total fluid volume of 1.402 liters is required, equivalent to 0.001 m^3, as the calculated volume must be multiplied six times to represent the volume needed when all valves on the Xmas tree are to be tested. The volume is used in later calculations related to the design of the subsea tank.

4.1.3 Volume of Test Fluid required to Control Annulus Pressure

As described in in Chapter 3.3, Annulus A will experience pressure changes during the lifetime of well. This especially concerns at start-up and shut-down of a well. During start up, the fluid in Annulus A is heated by the high tempered production stream flowing in the main bore. Due to the increment in temperature, the adjacent fluid in Annulus A will start to expand, resulting in a corresponding pressure build up in the annulus. The redundant volume causing the pressure increment is vented to the production line through the XOV. When the well experience a shut down, the temperature in the main bore will start to decrease as the adjacent environment holds a lower temperature than the production stream. Change in temperature will result in a temperature reduction of the fluid, resulting in a corresponding pressure reduction, in Annulus A. In such cases, the annulus must be refilled with fluid so that the pressure change is opposed, thus preventing damage of the tubing and casing that makes up the annulus. This is done by pumping test fluid through the service line into Annulus A.

Annulus A is filled with packer fluid during start-up, production and shut-in on oil producing wells. According to Brechan et al. (2017), brine is widely used as packer fluid, as it is cheap and easy to operate. Since brine and water have many similar properties, it is assumed that the properties of water can be used to calculate the thermal expansion of the packer fluid. The thermal expansion coefficient, α, for water varies with different temperatures. Figure 4.7 shows the thermal expansion coefficients for different water temperatures. The graph is made based on data from ToolBox (2003b).

However, Moe and Erpelding (2000) uses Equation 4.5 to calculate the volume expansion/reduction experienced in Annulus A. According to Moe and Erpelding (2000), a temperature change of 70 R, equivalent to 21.10 °C, is not uncommon during production start-up and shut-in of a well.

$$V = V_i(1 + \alpha \Delta T) \tag{4.5}$$

where

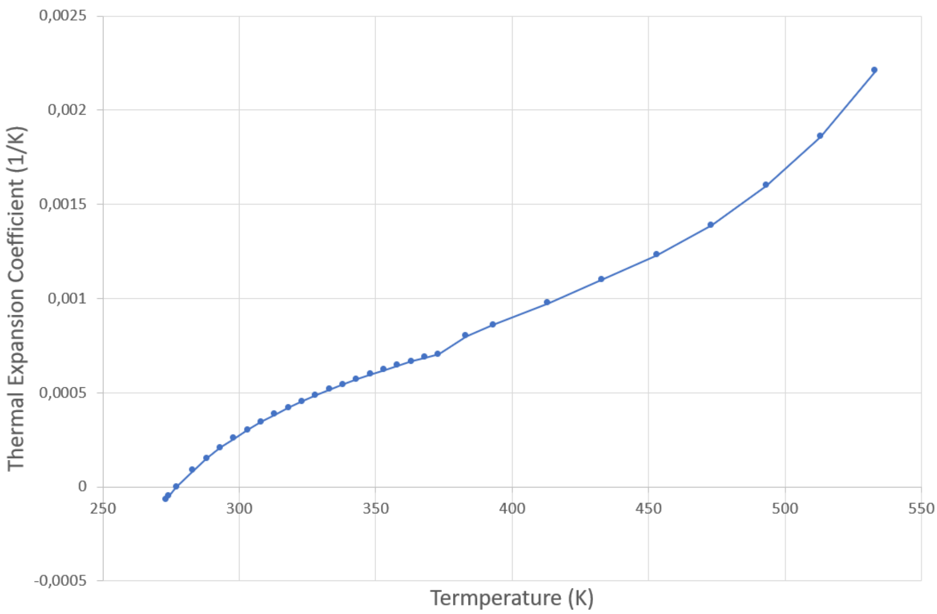


Figure 4.7: Thermal Expansion Coefficients for water with varying temperatures.

$$
\begin{aligned}
V &= \text{Expanded volume, in3} \\
V_i &= \text{Initial volume, in3} \\
\alpha &= \text{Fluid thermal expansivity, 1/R;} \\
\Delta T &= \text{Average fluid temperature change, } ^\circ\text{F;}
\end{aligned}
$$

According to Moe and Erpelding (2000), The properties of thermal expansion and compressibility, which both depends on temperature and pressure, are usually provided by the service company working on the field. However, typical thermal expansivity and compressibility values are given in Table 4.1. The table was originally made by Moe and Erpelding (2000).

Table 4.1: Typical thermal expansivity and compressibility values

Fluid type	Thermal expansivity, $\alpha(1/R)$	Compressibility, B_N (1/psi)
Water based	$2.5\text{x}10^{-4}$	$2.8\ \text{x}10^{-6}$
Oil based	$3.9 \text{ x } 10^{-4}$	$5.0\ \text{x}10^{-6}$
Ideal gas	$1/T_{abs}$	1/P

Using the data from Moe and Erpelding (2000), a 10 000 ft (3048m) long well with an annulus made up by a 9 5/8" casing with an inner diameter of 8,6", and a 7" tubing, will experience a change in volume equal to:

$$V_i = \frac{10000 * \frac{\pi}{4}(8.6^2 - 7^2)}{144} = 1361.35ft^3 = 242.5bbl \tag{4.6}$$

$$V = 242.5(1 + (2.5 * 10^{-4} * 70)) = 246.75bbl \tag{4.7}$$

$$\Delta V = 4.25bbl = 0.67m^3 \tag{4.8}$$

For a 10000 ft (3048m) long well experiencing a temperature reduction of 70 R (21.10 °C) in Annulus A, 0.67 m^3 of test fluid must be refilled in the annulus to oppose the reduction in pressure. The volume will be used in later calculations related to the design of the subsea tank.

Table 4.2 summarizes the volumes calculated in this chapter.

Table 4.2: Volumes calculated for an oil producing well

Operation	**Required Volume of MEG/methanol [m^3]**
Valve testing	0.001
Equalizing pressure across the DHSV	0.060
Controlling pressure changes in Annulus A	0.670
In total	0.731

4.1.4 Subsea Tank and Pump

On an oil producing well, MEG or methanol is used in valve testing and to control pressure changes experienced in Annulus A. As discussed above, a test fluid is required in order to perform these tasks. Since MEG and methanol prevents hydrate formation and reduce corrosion of the system, it is difficult to argue that the a another fluid can be utilized instead of these two. However, MEG or methanol can be supplied to the well in a different way than through the service line in the umbilical, as it is done on today's subsea system. A solution is to install a subsea tank close to the production site. The subsea tank will contain MEG or methanol which can be supplied from the tank to the well. The size of the tank must be designed based on how much MEG/methanol that is required when performing the various tasks.

As indicated in Table 4.2, a MEG/methanol volume of 0.731 m^3 is required to perform the listed operations. Thus, the subsea tank must be designed to store 0.731 m^3. However, the calculations are based on the assumption that testing of valves on the Xmas tree and the DHSV is performed once. The same applies to the shut-in of the well. The volume of the tank must be multiplied by the number of times the valve testing and shut-down are to be performed before the tank has to be refilled or replaced.

There are various types of subsea tanks suitable for storing MEG or methanol. Peyrony and Beaudonnet (2014) states that a piston tank is the best option for subsea chemical storage. A disadvantage of piston tanks is that they require perfect movement of the piston separating the two fluids in the tank. If the movement of the piston is imperfect, the two pressure zones will begin to merge and leakage of chemicals may occur (Festøy and Lundal, 2017). In addition, when fluid from the tank is supplied to the subsea field, it is desirable that the pressure in the tank is kept constant. For an elastic bladder tank and a pillow tank the pressure inside the tank will remain constant when fluid is drained from the tank. Festøy and Lundal (2017) states that a pressure-balanced bladder tank design is the best option for subsea chemical storage. The tank has, according to Festøy and Lundal (2017), a low weighted construction with excellent chemical compatibility.

On today's subsea system the utilized test fluid is vented to the service line and the production line. To create sufficient test pressure across a valve during valve testing on the Xmas tree, fluid is pumped into the system by the service line. The valve that is being tested is closed, and the pressure on the other side of the valve is vented to the service line. After testing, the differential pressure across the valve is equalized by the service line and the test fluid located within the Xmas tree is produced together with the hydrocarbons when the well is brought back into production. Similar procedures applies for testing the DHSV and controlling the annular pressure. Thus, a MEG/methanol containing subsea tank must be able to deliver and receive test fluid in order to perform valve testing and annular pressure control. This strengthen the argument of using a bladder tank, as the tank type is capable of both delivering and receiving without experiencing big changes in pressure within the tank. The same applies to a pillow tank.

With the proposed solution, a pump is required in order to deliver test fluid from the tank to the well when needed. According to Equinor (2019e), a suitable pump is the Marshalsea SMWS pump. The pump is a axial piston pump with three pistons which as has a fixed displacement volume of 0.65 ccm. According to Equinor (2019e), the pumps are compact and equipped with few parts. The pump has also been long-term tested. Another suitable pump, according to Equinor (2019e), is the Innova SLVP pump. This is a radial piston unit with five pistons. The volume displacement is fixed, ranging from 0.65-2.0 ccm. The pump is developed based on the Innova Subsea Grease Pump, but it is without gear and a balanced rotating assembly (Innova AS, 2015). This pump has not been been long-term tested, and it is expected that such a test will reveal the potential for improvement in materials, surface treatment related to wear, and seals (Innova AS, 2015). The two pumps presented are capable of pumping relatively small volumes, and are suitable for performing valve testing when the system is already filled with hydrocarbons. However, if Annlus A experiences big pressure changes and a volume of 60 m^3 or so must be supplied to the well, other pump types will be better suited. Using the Marshalsea SMWS pump or the Innova SLVP pump for such an operation will take too long time (Equinor, 2019e). The utilized pump must be of a modular design so that it can be retrieved by an ROV. The solution with a pump and a subsea tank is illustrated in Figure 4.8

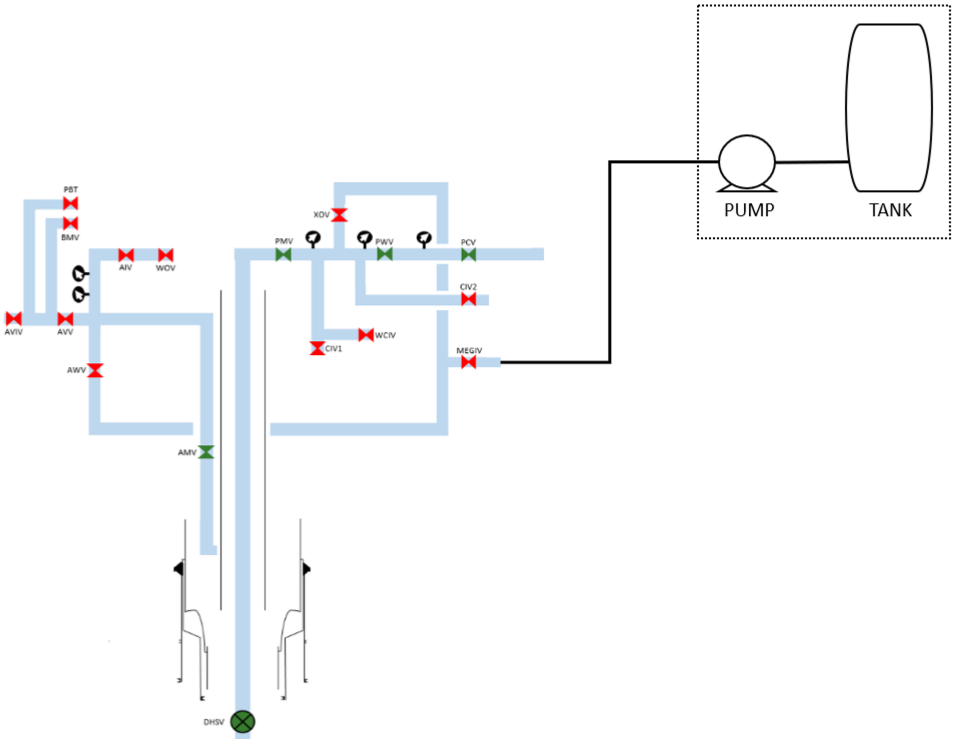


Figure 4.8: System configuration with MEG/methanol stored in a subsea tank close to the wellsite. A pump is needed in order to create sufficient test pressure across the valves during valve testing. The pump and the tank must be designed in one modul, so that they can be retrieved by a ROV simultaneously, illustrated by the dotted square.

4.1.5 Subsea Accumulator Tank and a Pressure Intensifier

Another solution is to install a subsea accumulator tank connected to the Xmas tree through the service line outlet on today's subsea system. The pressure inside a subsea accumulator tank will have the same pressure as the inside of the subsea system, which is suitable for controlling the pressure in Annulus A. However, as the pressure inside a subsea accumulator tank is the same as the pressure within the rest of the subsea system, the tank is not able to create the required differential pressure across the valve when performing valve testing.

In order to build up sufficient test pressure across a valve during testing, a pressure intensifier can be included in the solution. A pressure intensifier is a compact device that can be installed inside the subsea system. The device is capable of generating a higher pressure from a low-pressure hydraulic power source. This is done by a large diameter piston pushing a smaller diameter piston. According to Levinsen (2017), the movement increases the pressure "to a factor equal to the ratio: Larger diameter area divided by smaller diameter area." The intensifier is equipped with several valves, which controls the intensifier pistons. The piston movements continue until the end pressure is reached. Then, the piston stops and pressure is delivered at the high-pressure side of the device. According to Levinsen (2017), end pressures between 20 000 psi and 60 000 psi can be delivered by a pressure intensifier. A pressure intensifier are depicted in Figure 4.9.

Figure 4.9: An hydraulic pressure intensifier which can provide an end-pressure of 43.500 psi (Levinsen, 2017).

Thus, by installing a pressure intensifier within the subsea system, the system is able to build up sufficient test pressure one on side of the valve. The pressure on the other side of the valve must with this solution be vented to sea. The combination of a subsea accumulator tank and a pressure amplifier allows the requirements performed by the service line to be conducted without using the service line. However, the solution does not solve the problem with MEG/methanol supply, so that hydrates are prevented from forming within the subsea system. MEG/methanol would have to be placed in a subsea tank close to the wellsite. This makes the previous suggested solution with a subsea tank and a pump more suitable for oil producing wells. The solution with a subsea accumulator tank and a pressure intensifier is suitable for wells where hydrate formation is not considered an issue, such as water injection wells.

4.2 Gas Producing Wells

The service line provides several functions on gas producing wells. As for oil producing wells, the service line is used to achieve sufficient test pressure across the valves when testing the valves on the Xmas tree and the DHSV. The service line is also used to control the pressure in Annulus A. In addition, the service line supplies the well with MEG/methanol, preventing hydrates to form within the system. The fluids does also protect the inside of the Xmas tree from corrosion. As for oil producing wells, hydrates are considered an issue on gas producing wells. Gas molecules are obviously very accessible, and all hydrate formation conditions are therefore easily achieved.

It is of interest to remove the service line from the umbilical on gas producing wells. In order to do so, the listed functions provided by the service line must be performed in another way. In the way it is performed today, a test fluid is required. As suggested for oil producing wells, one could utilize seawater instead of MEG/methanol in order to perform the various functions. Seawater is cheaper and highly accessible, as it could be pumped in directly from the surroundings. However, the combination of gas and seawater under these temperature and pressure conditions will lead to hydrate formation in the system, which could lead to plugging of the Xmas tree. Gas producing wells may also produce formation water. As for oil producing wells, the combination of formation water and seawater will lead to scale. Due to higher possibility of both hydrate and scale formation, using seawater as test fluid on gas producing wells is not considered an option.

However, a possible solution enabling seawater as test fluid would be to install heaters on vulnerable hydrates areas on the Xmas tree. By doing so, one of the hydrate conditions is removed. As for oil producing wells, further cost analysis will be necessary to investigate whether this is a possible solution for gas producing wells.

In order to remove the service line, the various tasks performed by the service line on today's subsea system must be performed in another way. As for oil producing wells, the solution of using seawater as test fluid is excluded as this will lead to large amount of hydrates forming within the subsea system. However, the solution proposed for oil producing wells with installing a subsea tank and a pump close to the production site, can also work for gas producing wells. Storing MEG or methanol close to the production site ranter than supplying it continuously to the well through the service line, can lead to potential cost savings. As for oil producing wells, the dimensions of the subsea tank are determined by the following:

- The required volume of test fluid needed when equalizing the pressure across DHSV.
- The required volume of test fluid needed during valve testing.
- The required volume of test fluid needed when re-filling the depressurized volume in the annulus.

The listed volumes are calculated in the following chapters.

4.2.1 Volume of Test Fluid required when Equalizing Pressure Across the DHSV

As for oil producing wells, the differential pressure across the DHSV must be equalized before the valve is opened. By pumping MEG or methanol through the service line in the umbilical, into the tubing string above the DHSV, the differential pressure across the valve is equalized.

Most gas producing wells are equipped with a completion of 9 5/8 inches (0.2444m) or smaller, with an inner diameter of 8 inches (0.2032m). Since the well is a gas producing well, the tubing string above the DHSV is initially filled with gas. The volume is denoted V_0. To equalize the pressure across the valve, MEG or methanol is filled up in the tubing string compressing the volume of gas that was initially there. The volume of the compressed gas is denoted V_1 and the volume of MEG or methanol is denoted V_2, see Figure 4.10. Equation 4.9 is used to calculate the initial volume of gas in the tubing string above the DHSV, before the valve is tested. As for oil producing wells, the setting depth of the DHSV ranges from 100m to 500m (Sangesland et al., 2012). Obviously, the volume in the tubing string above the DHSV is determined by the setting depth of the valve. The tubing string volume with varying setting depths is shown in Figure 4.11 and Figure 4.12.

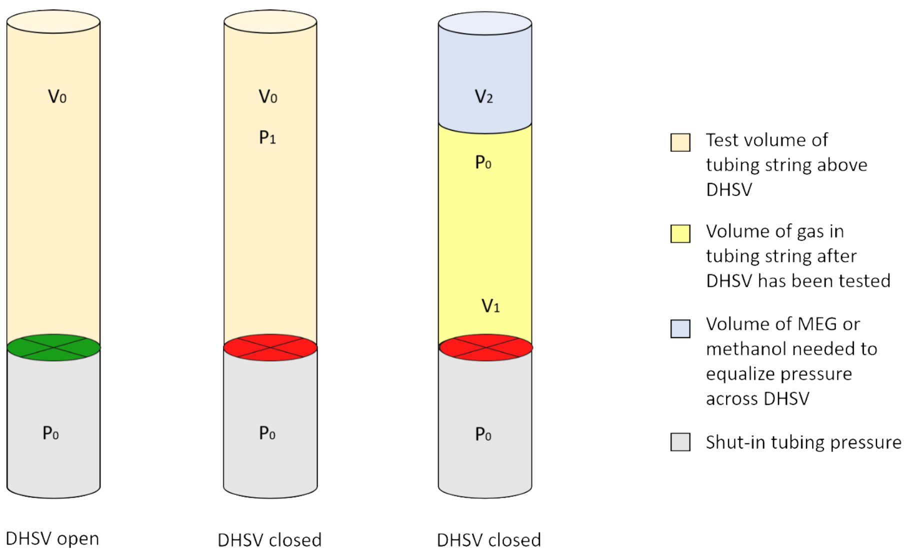


Figure 4.10: The different scenarios during and after testing of the DHSV

$$V_0 = \frac{\pi}{4} * 0.2032m^2 * h \tag{4.9}$$

Where h is the setting depth of the DHSV.

To calculate the compressed volume of gas, V_1, and the required volume of MEG/methanol needed in order to equalize the pressure across the DHSV, V_2, the ideal gas law is utilized. By assuming that the gas is methane with a compressibilty factor, Z, equal to 1 and that the process is isothermal, the ideal gas law can be simplified to:

$$V_0 P_1 = V_1 P_0 \tag{4.10}$$

where $P_1 = P_0 - \delta P$

δP is the differential pressure across the DHSV during a leakage test. As stated by API RP 14B (2015), a differential pressure of 70 bar is required across the DHSV during testing. However, it can be difficult to achieve 70 bar across the valve throughout the lifetime of the well as the shut-in tubing pressure decreases with increasing production time. In these scenarios, one must test with the differential pressure that is available (Equinor, 2018b). It is assumed that a differential pressure of 70 bar is achieved in the following calculations.

From Figure 4.10 it is clear that:

$$V_1 = V_0 - V_2 \tag{4.11}$$

To calculate V_2, one must combine Equation 4.10 with Equation 4.11. The following equation is then obtained.

$$V_2 = V_0 - \frac{V_0 P_1}{P_0} \tag{4.12}$$

The reservoir pressure, P_{res}, is assumed to be 345 bar. As in Chapter 4.1, the well is assumed to have a length of 10000 ft, equal to 3048m. ρ_{CH_4} is equal to 0.656 kg/m^3 (ToolBox, 2003a). Equation 4.13 is used to calculate the shut-in tubing pressure, P_0.

$$P_0 = P_{res} - \rho_{CH_4} g h = 344.8 bar \tag{4.13}$$

For a DHSV setting depth of 500m, V_2 = 3.30 m^3 and V_1 = 12.92 m^3. This means that a gas producing well with a DHSV setting depth of 500m, producing only methane gas, requires a fluid volume of 3.30 m^3 in order to re-fill the tubing string above the DHSV so that the pressure across the valve is equalized. The volume will be utilized in further calculations related to the design of the subsea tank.

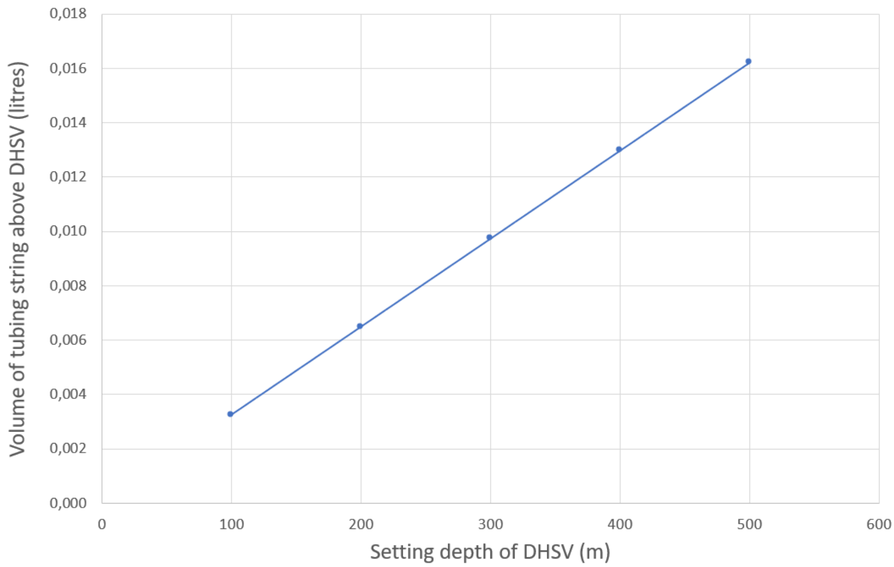


Figure 4.11: Volume in the tubing string above DHSV, in litres, with varying DHSV setting depths

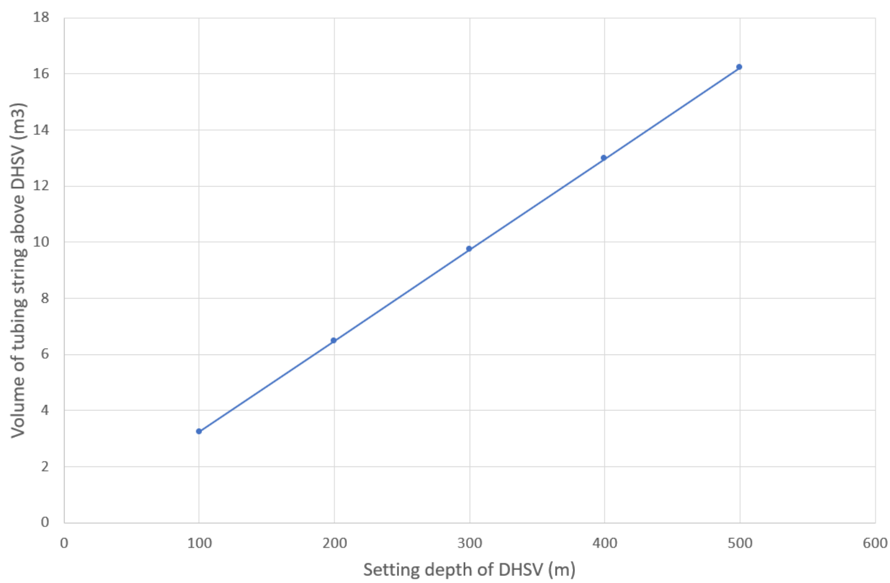


Figure 4.12: Volume in the tubing string above DHSV, in m^3, with varying DHSV setting depths

4.2.2 Volume of Test Fluid required during Valve Testing on the Xmas Tree

As for oil producing wells, test fluid is required to create sufficient test pressure across the valves on the Xmas tree in order to perform valve testing. The volume of test fluid required to fill the system will vary depending on the valve being tested. As for oil producing wells, the required volume of test fluid necessary for leakage testing is not the volume that dimensions the subsea tank.

When performing valve testing on a gas producing well, there will be gas located in the system prior to testing. To create sufficient test pressure across the valve being tested, MEG/methanol is introduced to the system, building up the pressure on one side of the valve. When introducing MEG or methanol into the system, which initially contains gas, the gas is compressed. It is assumed that this is an isothermal process. For isothermal process, the temperature of the system remains constant, thus

$$P_1V_1 = P_2V_2 \tag{4.14}$$

Isotherms for ideal gases are shown in Figure 4.13. Thus, a bigger volume of MEG or methanol is required when equalizing a differential pressure across a valve producing from a reservoir with low shut-in tubing pressure, compared to a reservoir with high shut-in tubing pressure. The amount of test fluid required is field specific. In the following calculations it is assumed that the shut-in tubing pressure is equal to 344.8 bar, as calculated in Chapter 4.1.

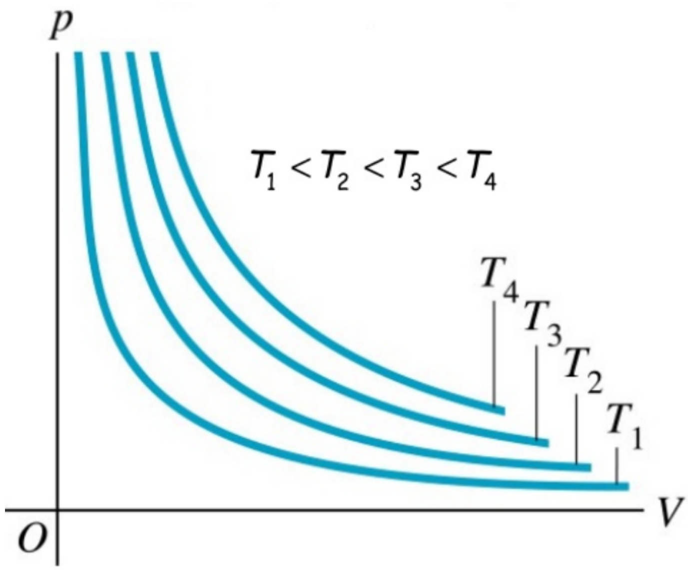


Figure 4.13: Isotherms for an ideal gas (Albania Energy Association, 2014)

As the volume of test fluid required during valve testing is not the volume dimensioning the subsea tank, it is assumed that the required volume of MEG/methanol needed during valve testing is the same as filling a wing bore with an inner diameter of 7 inches (0.1778m), with a length varying from 0.5 to 2 m. Equation 4.15 is used to calculate the initial volume of gas in the 7 inch wing bore.

$$V_i = \frac{\pi}{4}(0.1778)^2 h \tag{4.15}$$

Where h is the length of the wing bore.

Figure 4.14 shows the volume of the wing bore with lengths ranging from 0.5m to 2m.

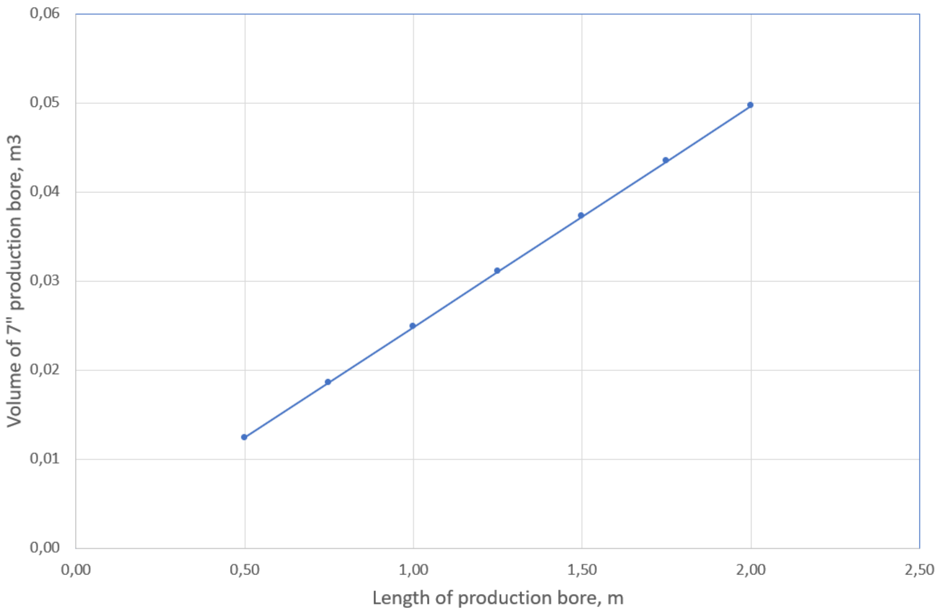


Figure 4.14: Volume of wing bore with varying lengths

It is assumed that the gas filling the wing bore is methane gas (CH_4), having a compressibility factor, Z, equal to 1. The process is assumed to be isothermal, thus the ideal gas law is simplified to:

$$V_i P_1 = V_1 P_i \tag{4.16}$$

Where $P_1 = P_i - \delta P$

Also, as illustrated in Figure 4.15:

$$V_1 = V_i - V_2 \tag{4.17}$$

By combining Equation 4.16 with Equation 4.17, the required volume of MEG/methanol during valve testing, V_2, can be calculated. Thus

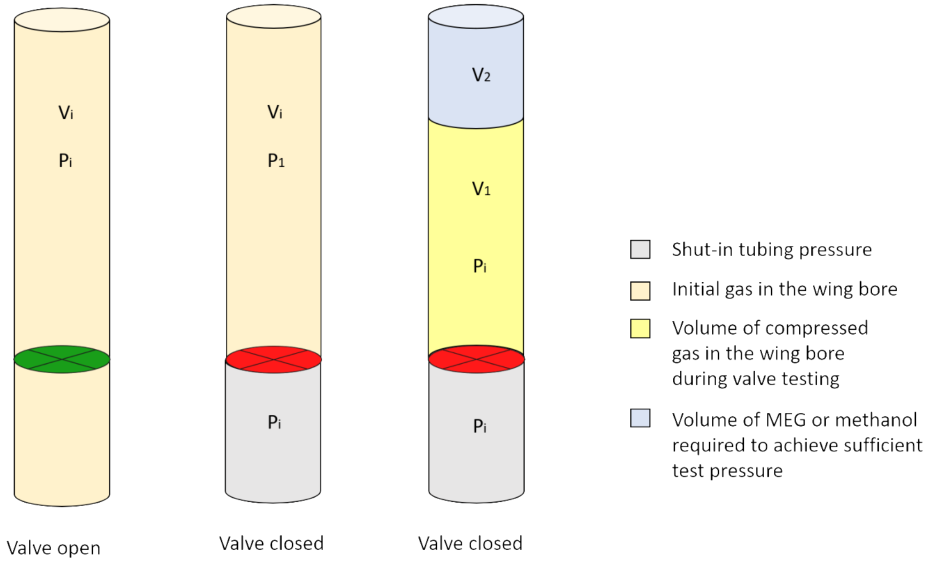


Figure 4.15: Test scenario of filling a wing bore. The initial gas in the wing bore is compressed by MEG/methanol added to the system.

$$V_2 = V_i - \frac{V_i(P_i - \delta P)}{P_0} \tag{4.18}$$

δP is set to 70 bar, as required by API RP 14B (2015). V_i is calculated to be 0.05m^3 for a wing bore length of 2m, as shown in Figure 4.14. As calculated in Chapter 4.1, the tubing shut-in pressure, P_i, is equal to 344.8 bar. For a 2m long wing bore, a volume of MEG/methanol, V_2, equal to 0.10 m^3 is required in order to achieve sufficient test pressure across the valve on the Xmas tree. As previously stated, MEG/methanol is supplied to the system a total of six times when all the valves on the Xmas tree are to be tested. Thus, a total fluid volume of 0.6 m^3 is required during testing of the Xmas tree. The volume is used in later calculations related to the design of the subsea tank.

4.2.3 Volume of Test Fluid required for Annular Pressure Control

As explained in Chapter 3.3, gas producing wells will experience pressure changes in Annulus A caused by the fluid in the well bore. At star-up of a well, the produced gas will heat up the packer fluid in Annulus A. The process is reversed when the well is shut down. The gas located in the well bore is then cooled by the surroundings, causing the packer fluid in Annulus A to contract. Thus, the largest volume changes in Annulus A are expected during start-up and shut-down of a well. When the packer fluid expands or contracts, Annulus A must be vented or refilled in order to prevent damage of the pipes making up the annulus.

To determine the dimension of the subsea tank for the proposed solution, one must calculate the amount of MEG/methanol required when venting/refilling Annulus A. It is assumed that the packer fluid located in Annulus A is brine. This means that the volume calculated in Chapter 4.1.3 is valid for gas producing wells too. Thus, a volume of $0.67m^3$ must be bleed off or refilled in order to control the pressure in Annulus A on a gas producing well.

Table 4.3 summarizes the volumes calculated in this chapter.

Table 4.3: Volumes calculated for a gas producing well

Operation	Required Volume of MEG/methanol [m^3]
Valve testing	0.60
Equalizing pressure across the DHSV	3.30
Controlling pressure changes in Annulus A	0.67
In total	4.57

4.2.4 Subsea Tank and Pump

On a gas producing well, MEG or methanol is used in valve testing and to control pressure changes experienced in Annulus A. On today's subsea system test fluid is supplied to the well by the service line in the umbilical. In order to remove the service line in the umbilical, both valve testing and annular pressure control must be conducted differently than what it is today. As hydrates and scale are likely to occur on gas producing wells, using seawater as test fluid is not considered as an option. However, as purposed for oil producing wells, MEG or methanol can be supplied to the well from a subsea tank installed close to the well site. The subsea tank will be equipped with a pump, so that MEG/methanol can easily be supplied from the subsea tank to the well. The size of the tank must be designed based on how much MEG/methanol that is required when performing valve testing and annular pressure control.

As indicated in Table 4.3, a MEG/methanol volume of 4.57 m^3 is required to perform the listed operations. Thus, the subsea tank must be designed to store 4.57 m^3. However, the calculations are based on the assumption that testing of valves on the Xmas tree and the DHSV is performed once. The same applies to the shut-in of the well. The volume of the tank must be multiplied by the number of times the valve testing and shut-down are to be performed before the tank has to be refilled or replaced.

As discussed for oil producing wells, the bladder tank and the pump in the proposed solution are suitable for gas producing well too. Based on the calculations performed in this chapter, the subsea tank must be bigger on an gas producing well than on an oil producing well.

Since hydrate formation is considered an issue on gas producing wells, the pressure accumulator tank with an pressure intensifier is not considered a suitable solution.

4.3 Water Injection Wells

The service line makes it possible to perform several tasks on water injection wells. As for oil and gas producing wells, the service line is used to achieve sufficient test pressure across the valves during valve testing of the Xmas tree, when testing the DHSV and to control the pressure in Annulus A. In difference from oil and gas producing wells, the differential pressure across the DHSV is equalized by the injection line and not the service line. After the valve has been tested, water is pumped in on one side of the valve until the differential pressure is equalized. The valve is then opened, and the injection of water can continue.

Water injection wells inject both seawater and produced formation water. At production start of a well, the well produce mostly hydrocarbons. The rate of hydrocarbons produced will decrease with increasing production time, and after a while many wells will start to produce formation water. Thus, if water injection is required at production start of a well, seawater will be injected. When the well starts to produce water, the produced water must be discarded in some way. The produced water is too contaminated to be dumped directly at sea and must be treated first, which is a costly process. The produced water can also be injected back into the reservoir, maintaining a higher pressure in the reservoir thus keeping the production rate higher.

4.3.1 Flow Assurance Challenges

On a water injection well, gas is usually not present. Since hydrates formation requires the presence of water and gas at low temperature and high pressure, hydrates are not considered an issue on water injection wells. However, several wells in Campos Basin in Brazil have experienced hydrate formation in the injection string on water injection wells, which resulted in complete blockage of the string. A study was conducted to find out how gas had entered the well, and it was concluded that the possible causes were cross flow between formation zones and free gas segregation during shutdown periods (Rodrigues et al., 2009). If a water injection well is shut down for extended periods, gas may start to migrate up in the injection string. During shutdown of the well, the DHSV is closed but they often tend to leak. Gas will migrate into the Xmas tree, and since the Xmas tree already contains water, hydrate conditions are achieved.

The problem with gas segregation in the injection string is usually treated with pushing water into the system at regular intervals, removing the accumulated gas inside the system. However, it can be a problem if gas is pushed down the injection string by cold water without another fluid separating the two fluids. In worst cases, the treatment can make the problem of hydrates even worse. At Bay du Nord at Newfoundland and at Wisting in the Barent Sea, heating the water before it is injected is considered as an option in order to avoid hydrate formation within the system. Another hydrate strategy is to heat up the Xmas tree on vulnerable areas where hydrate formation is more likely to occur.

Rodrigues et al. (2009) recommends to treat the issue of hydrate formation on water injection wells with the following:

1. “Facilities for the replacement of fluids in the production line for diesel or other suitable fluid before restarting production. ”
2. “The use of chemicals such as methanol and MEG in the WCT loop and at the top of production strings.”
3. “Downhole injection of methanol or MEG.”

With the service line removed, injecting methanol or MEG is not be an option. However, there are several injection wells that are not subjected to gas segregation in the injection sting. Many of these wells are placed in an active water aquifer. At these wells, a significant amount of gas is unlikely to accumulate in the injection string and hydrate formation is therefor not considered an issue.

4.3.2 Valve Testing

An important task enabled by the service line is the creation of sufficient test pressure across the valves during leakage testing of the Xmas tree and the DHSV. As described in Chapter 3.1, the test pressure is created by closing a valve so that the shut-in pressure works on one side of the valve while the other side of the valve is ventilated using the service line. If the service line is removed, the pressure on one side of the valve must be bleed off in another way.

The water injected on water injection wells is delivered to the field by an injection line connected to topside or to shore. Usually, several water injection wells are supplied with water from the same injection line, as illustrated in Figure 4.16. This makes it difficult to bleed off the pressure on one side of the valve on one well, as the pressure change will affect the other wells supplied by the same injection line.

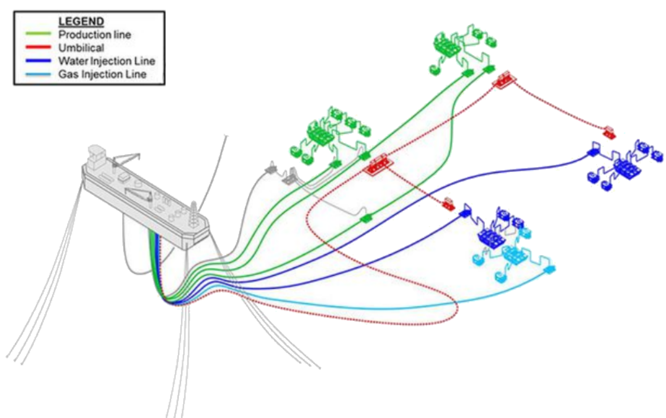


Figure 4.16: A subsea configuration with wells tied back to a FPSO. One injection line supplies a manifold with water. The water is distributed out to several injection wells (ExxonMobil, 2019)

In order to achieve sufficient test pressure when leakage testing the valves on the Xmas tree, the pressure on one side of the valve can be bleed off to sea. This could be done at the inlet where the service line is located on today's subsea system, but the action will lead to greater emissions to sea. However, hydrates are not considered an issue on many of the water injection wells and the test fluid utilized on these wells may not necessarily be MEG or methanol. A test fluid which could be bleed off directly to sea without increasing the emission, is seawater. Seawater is cheaper than MEG and methanol, it is highly accessible as the subsea system is submerged in it, and the used test fluid could be dumped directly to sea without any further treatment.

New challenges arises should seawater be used as test fluid on water injection wells. If seawater is used as test fluid during valve testing on a well that is injecting produced formation water, a mixture of formation water and seawater will occur. Formation water contains Barium, usually at a concentration of 40 mg/L (Equinor, 2019f), while seawater contains sulfate. The mixture of these two fluid will result in precipitation. Equinor (2019b) performed an experiment where barium-containing water was mixed with seawater. The result is shown in Figure 4.17. The precipitation shown to the right in the figure, occurred immediately after the two liquids were mixed. However, the amount of precipitation will not be significant thus not a problem during valve testing on an injection well (Equinor, 2019f). When the water injection well is put back into operation, the precipitation will be transported out of the system together with the injected water.

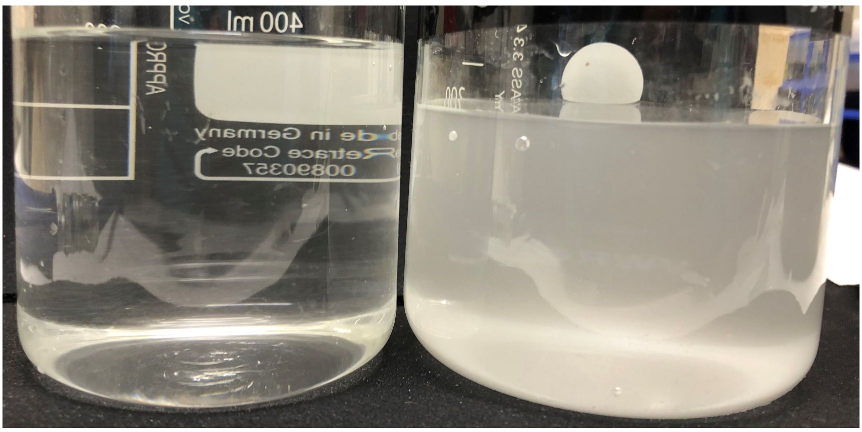


Figure 4.17: The flask to the left contains a mixture of seawater and formation water with a low content of barium. The flask to the right contains a mixture of seawater and formation water with a high content of barium. As one can see, the precipitation is greater in the flasks to the right (Equinor, 2019b).

Barrier test procedures for valve testing on the Xmas tree are the same for water injection wells as for oil and gas producing wells. This is because water injection wells may experience back flow of hydrocarbons from the reservoir. Hence, the test procedures described in Chapter 3.1 are valid for water injecting wells too. One can assume that the injected water will behave similar to the oil on oil producing wells. Thus, the same amount of test fluid as calculated in Chapter 4.1.2 is required when leakage testing the valves on a water injecting Xmas tree. Hence, a test fluid volume of 1.4 litres must be supplied to the system in order to perform testing of the valves on the Xmas tree.

4.3.3 Annular Pressure Control

As for oil and gas producing wells, the packer fluid in Annulus A on water injection wells will expand and shrink due to temperature changes caused by the fluid in the wellbore. This especially concerns start-up and shut-down of a well. The injected water is supplied to the field by a service line connected to either topside or to shore. The temperature of the injected water will depend on the length of the injection line. If the water is transported over long distances on the seabed, the temperature of the injected water will go towards the temperature of the sea. Thus, the injected water is likely to have a temperature of around 4°C.

At start up of a water injection well, the injected water will have a lower temperature than the packer fluid located in Annulus A. This will cause the packer fluid to contract, and the annulus must be refilled in order to prevent damage to the surrounding casing and tubing. Likewise, when the well is shut-down, the water contained in the injection string will be heated up by the surroundings. As the injection of cold water has stopped, the packer fluid within Annulus A will be heated up by the surroundings and start to expand. The encountered volume must be bleed off in order to prevent damage on the surrounding casing and tubing. With today's solution both refilling and venting of Annulus A is performed by the service line. If the service line is removed, other solutions must be considered.

Two solutions are presented below. The first is to place nitrogen gas on top of the well, which would work as a pressure accumulator responding to the volume change in Annulus A. The second solution is to pump seawater directly into the system where the service line is installed on today's subsea system. The seawater is used for valve testing and annular pressure control.

4.3.4 Nitrogen Pillow

A solution proposed by Bekkeheien et al. (2019) is to place nitrogen gas on top of the well. The nitrogen gas, called a nitrogen pillow, will act as a pressure accumulator counteracting the volume change in the annulus. When the volume in Annulus A expands or contracts, the gas is compressed or expanded in response to this. The solution is illustrated in Figure 4.18.

A challenge with the solution is to avoid nitrogen from escaping the system through the service line when opening the annulus master valve. A dip tube is installed so that the liquid in Annulus A is connected to the service line. The dip tube creates a gas lock, which prevents the nitrogen from escaping the system when the valve is opened. According to Bekkeheien et al. (2019), the dip tube can be extended 100m or more down the annulus depending on the level of the nitrogen.

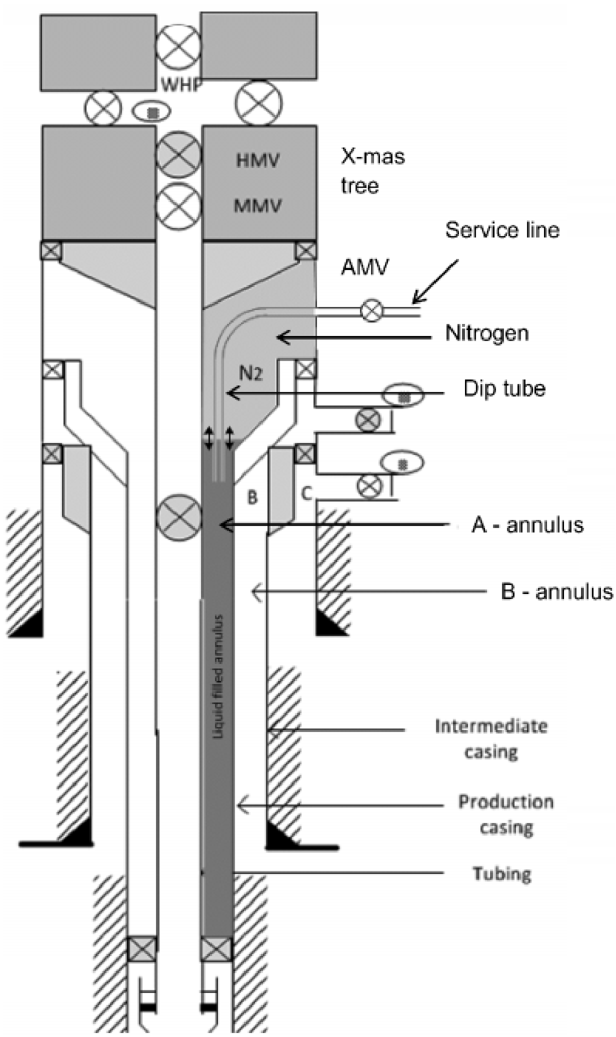


Figure 4.18: "Schematic diagram of a subsea well with a fluid filled annulus and a nitrogen pressure accumulator (Bekkeheien et al., 2019)

The "Nitrogen Pillow"-solution reduces the need to access Annulus A, as annular pressure control is provided by the nitrogen gas. However, the solution does not enable valve testing on the Xmas tree and the DHSV without the service line. The solution must therefore be combined with another solution for the service line to be completely removed on water injecting wells. In order to perform valve testing on water injection wells without using the service line, a pressure intensifier can be combined with the "Nitrogen Pillow"-solution.

For the water injection wells where hydrate formation is not considered an issue, the combination of these two solutions would allow all service line requirements to be performed without using the service line.

4.3.5 Using Seawater as Test Medium

As discussed earlier, it would be beneficial to use seawater as test fluid on water injection wells where hydrates are not considered an issue. A solution allowing the use of seawater in valve testing and annular pressure control, is the installation of a pump connected to the system where the service line enters the Xmas tree on today's subsea systems. Pumping seawater directly into the subsea system is a cheap and simple solution. The utilized seawater can be dumped directly to sea after it has been utilized without any further treatment.

The solution requires a pump that can work with seawater over a longer period. The pump must be capable of supplying the system with sufficient seawater during valve testing and annular pressure control. Since the volume in Annulus A may expand or shrink, a system requirement is that the pump must be able to pump water into the system as well as pumping water out of the system. According to Equinor (2019e), a suitable pump is a Marshalsea SMW Water/Glycol pump, depicted in Figure 4.19. The pump has a maximum working pressure of 690 bar (10 000 psi) and a maximum flow capacity of 1.81 l/min. As calculated in Chapter 4.1.2, a volume of 1.4 litres is required when testing all the valves on the Xmas tree. This means that the pump could deliver the necessary amount in about 47 seconds. The pump is a compact pump with all externally exposed components made out of stainless steel (Marshalsea Hydraulics, 2019).

Figure 4.19: The Marshalsea SMW Water/Glycol pump (Marshalsea Hydraulics, 2019)

The Marshalsea SMW Water/Glycol pump is designed for water-based fluids. Thus, modifications and testing are required in order to evaluate if the pump can be designed for seawater too. This is a highly corrosive environment, and special requirement are set to the material of the pump. A material that can sustain such a corrosive environment is stainless steel of the type duplex 25 Chrome. With this material, corrosion will not occur as long as the temperature is kept below 20°C.

The pump installed must be equipped with a filter preventing fishes, shrimps and other organic material from entering the system. The filter must be installed at the inlet of the pump, preferably as high above the seabed as possible. This to reduce the inflow of sand caused by sea currents and other subsea activities which creates movements of sand on the seabed. Such movements will make the filter to plug more easily. However, after a certain time of operation the filter will be plugged due to large amounts of organic material in the seawater. It is therefor favourable that the valve, pump and filter are designed with a modular design so that the components can easily be retrieved by an ROV when necessary. This is also advantageous, as maintenance of the pump will be necessary after a few years of operation.

The configuration of the suggested solution is illustrated in Figure 4.20. The valve placed between MEGIV and the pump, is a by-pass valve which prevents the pump from exceeding the required pressure that the Xmas tree are designed to. Without the by-pass valve, the pump may continue to operate after the required pressure is reached which could potentially damage the system.

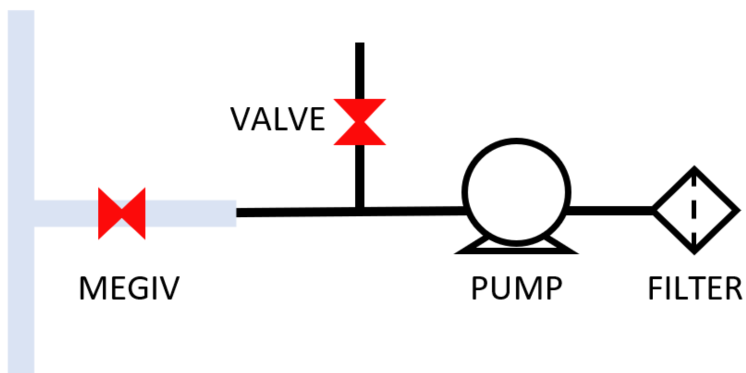


Figure 4.20: System configuration of the solution with a subsea pump and a filter

At start-up of a water injection well, the packer fluid within Annulus A is cooled by the injected water, which causes the packer fluid to contract. With the suggested solution, seawater is pumped into the annulus in order to control the pressure changes. However, as discussed in Chapter 4.3.1, gas can migrate up in Annulus A if the well has been put out of operation for a long period of time. If so, and seawater is pumped into the annulus to control pressure changes, hydrate formation conditions in the annulus are achieved. Thus, seawater can only be used as test medium on water injection wells where gas migration is unlikely to occur. Should hydrates form within Annulus A, it is not expected that this will cause severe damage on the surrounding casings and tubing. According to Equinor (2019d), hydrates do not expand in the same way water expands when it freezes. However, whether hydrates are formed or not, pumping seawater into Annulus A will create a highly corrosive environment inside the annulus. A limitation is whether the casing and tubing that makes up the annulus can handle this corrosive environment. Most likely, the pipes must be designed in another material in order to do so.

Another option is to include a subsea tank in the suggested system. This would be the same solution as presented in Chapter 4.1.4. By installing a subsea tank beside the pump, fluid can be pumped back and forth performing the requirements of valve testing and annular pressure control. The test medium utilized could be seawater, MEG or methanol. Further analysis regarding system design, cost and more are required in order to verify the solutions.

4.3.6 Subsea Accumulator Tank and a Pressure Intensifier

The solution with using a subsea accumulator tank together with a pressure intensifier is described in Chapter 4.1.5. The solution is suitable for wells where hydrates are not considered an issue. As discussed above, this concerns water injection wells located within an active water aquifer. The subsea accumulator tank is installed in order to control pressure changes in Annulus A, while the pressure intensifier is able to generate a higher pressure from a low-pressure hydraulic power source. The low-pressure hydraulic source is the water located inside the Xmas tree prior to valve testing. The subsea accumulator can use seawater as medium in order to perform annular pressure control. The tank is connected to the Xmas tree by a jumper connected to the three through where the service line enters the Xmas tree on today's subsea system. The pressure intensifier is installed at the same place. By doing so, necessary design changes of the Xmas tree used today are avoided. Figure 4.21 illustrates the configuration of the solution.

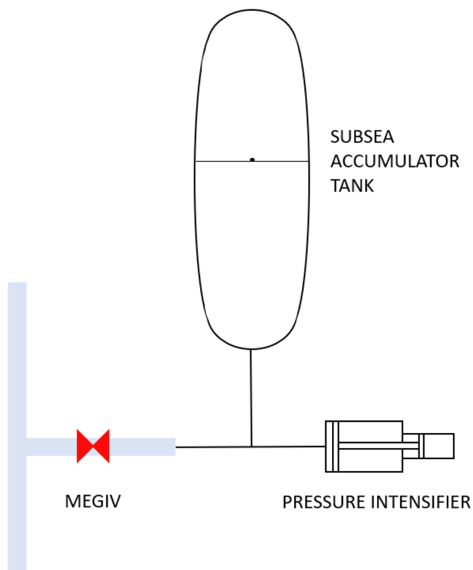


Figure 4.21: System configuration of the solution with a subsea accumulator tank and a pressure intensifier

4.4 CO_2 Injection Wells

The service line makes it possible to perform several tasks on CO_2 injection wells. As for oil and gas producing wells, the service line is used to achieve sufficient test pressure across the valves during valve testing on the Xmas tree, when testing the DHSV and to control the pressure in Annulus A. As for water injection wells, the test pressure across the DHSV is equalized using the injection line, and not the service line.

There are two types of CO_2 injection wells. Most CO_2 injection wells are injecting CO_2 as an EOR method where CO_2 is injected into an oil reservoir in order to increase the oil production rate. CO_2 can also be injected into a reservoir for permanent storage, as part of the concept Carbon Capture and Storage (CCS). CO_2 coming from industrial production is captured and stored in depleted reservoirs, reducing the amount of CO_2 emissions to the atmosphere. The difference between the CO_2 from the two types of injection wells are the water content of the injected CO_2. The water content in the CO_2 coming from industrial production is usually lower than the one used in EOR, and are considered ”cleaner”. The number of CO_2 injecting wells are expected to increase, as Equinor together with other companies working on the Norwegian continental shelf, announced that they will make production from the Norwegian continental shelf emission free by 2050. To remain a profitable production, new solution concerning CO_2 injecting wells are required. The injection wells related to CCS are the ones being discussed in this thesis.

4.4.1 Flow Assurance Challenges

On CO_2 injection wells, hydrate formation are considered an issue. Since the injected CO_2 contains water, all hydrate formation requirements are present on this type of wells. However, hydrates made out of CO_2 are considered more stable compared to CH_4-hydrates, which gives more time to solve hydrate problems when dealing with CO_2-hydrates.

On CO_2 injection wells, the injected CO_2 is transported in liquid phase condition. Hydrate formation during transportation depends on the water content of the CO_2. At Northern Light for instance, the maximum water content in the CO_2 coming from onshore, is 30 ppm (Equinor, 2018a). As the water content is low, free water is not present in the transportation system resulting in low probability of hydrate formation. The water content increases in the reservoir, and the probability of hydrate formation increases accordingly. Hydrate formation rate depends on the salt content of the water present. As shown in Figure 4.22, the hydrate formation curve is moved to the left when combined with water containing 5wt% NaCl. On the Northern Light project it is expected that the hydrate temperature is reduced by 3°C at bottom hole, since the water present contains 5wt% NaCl and not 0wt% like distilled water (Equinor, 2018a).

Salt precipitation can be an issue on CO_2 injection wells, depending on the water content of the CO_2 that is being injected. For instance, scale is not expected to be an issue during transportation and in the well bore on the Northern Light project due to low water content. However, salt precipitation has occurred on CO_2 injecting wells on Snøhvit, which has been treated with MEG and scale inhibitors (Equinor, 2018a). Thus, if seawater is used

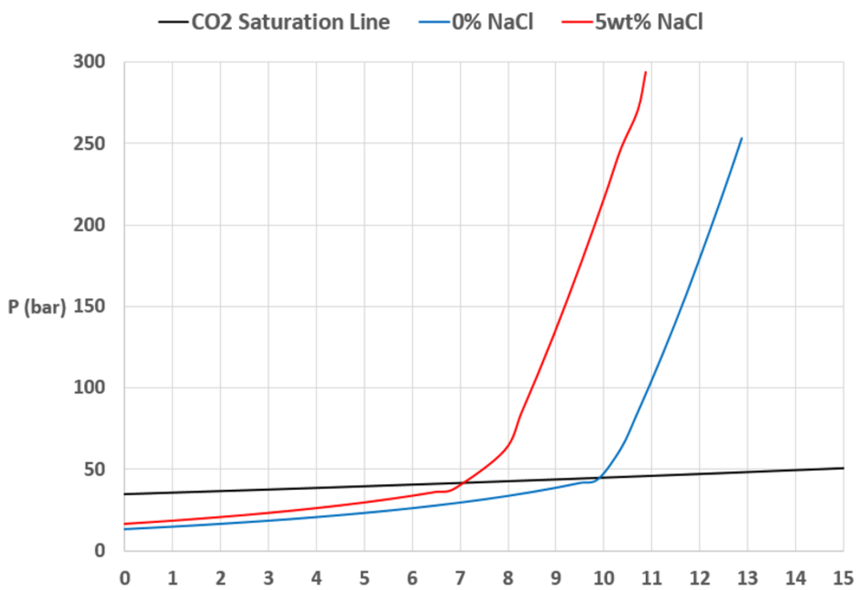


Figure 4.22: "Hydrate curves at bottom hole (in saturated water) . Hydrate curve base on 5wt% NaCl in the formation water given by the red curve. and 0wt%NaCl in the formation water with the blue curve" (Equinor, 2018a).

as test fluid on CO_2 injection wells, the probability of getting scale formation within the system is considered increase.

4.4.2 Valve Testing

An important task enabled by the service line is the creation of sufficient test pressure across the valves when performing testing of the Xmas tree. On CO_2 injection wells, the injected CO_2 is in liquid phase. When performing valve testing, it is important to keep the injected CO_2 in the liquid phase, so that the testing can be performed under stable temperature and pressure conditions. As described in Chapter 3.1, one aim to achieve a pressure curve equal to the one shown in Figure 3.1. Should some of the injected CO_2 boils off and go from liquid phase over to gas phase during valve testing, unstable conditions are created making it difficult to achieve valid test results. A phase diagram of CO_2 is shown in Figure 4.23. Different methods are utilized to keep the injected CO_2 under liquid phase conditions during operation.

On the Northern Light project, the subsea system will be depressurized through a service line going over to Oseberg A. By reducing the pressure in the system, the injected CO_2 is kept under liquid phase conditions (Equinor, 2018a). On the Snøhvit field in the Barents Sea, the Xmas tree are filled with MEG or methanol before valve testing is performed, so that all CO_2 in the system are displaced prior to testing. This is also done before testing the DHSV. The testing is performed by using MEG or methanol which ensures that the test is performed under one-phase conditions which in turn ensures valid test results. The procedure requires a lot of MEG, which on today's subsea system is supplied by the service line.

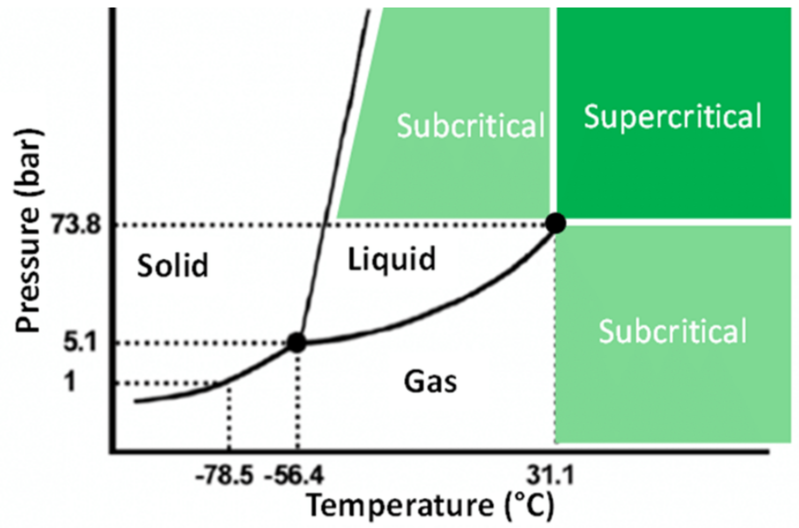


Figure 4.23: Phase diagram of CO_2 (Laboureur et al., 2015)

On CO_2 injection wells, the Xmas tree will be filled with liquid CO_2 before valve testing is performed. In the previous chapter, a suggested solution was to utilize seawater as test fluid instead of MEG or methanol on water injection wells. Since the Xmas tree on a CO_2 injecting well is filled with CO_2 before testing, CO_2 and seawater are combined when performing valve testing. By pumping in seawater, more salt is added to the system which will increase the rate of hydrate formation. As hydrates are considered as such an issue on CO_2 injection wells, using seawater as test fluid is not considered as an option on CO_2 injection wells. To be able to remove the service line on CO_2 injection wells, other solutions must be considered.

Should fluid be supplied to the well in order to perform valve testing, the required volume of fluid must be calculated. One can assume that the liquid CO_2 will behave similar to the oil on oil producing wells described in Chapter 4.1.2. It is therefore assumed that the bulk modulus for CO_2 ranges from 1.1 GPA to 3.2 GPa. Thus, a required volume of test fluid during valve testing on a CO_2 injection well is calculated to be 1.4 litres, equivalent to 0.001 m^3.

Another important feature enabled by the service line is to bled off the pressure on one side of the valve, so that a sufficient differential pressure is created across the valve when performing valve testing. This is done when testing the valves on the Xmas tree and when testing the DHSV. Usually for CO_2 injection wells, the injection line supplying the field with CO_2 supplies not only one well, but several wells as illustrated in Figure 4.16. This makes it difficult to bleed off the pressure on one side of the valve, as the pressure change would affect the pressure on other wells too. In order to remove the service line, the pressure on one side of the valve must be bled off in another way.

As calculated in Chapter 4.1.2, a volume of 1.4 litres is required in order to build up sufficient test pressure on one side of the valve located on the Xmas tree. By assuming similar behavior of the injected CO_2 as oil on an oil producing well, one can assume that 1.4 litres of fluid must be bled off in order to obtain a differential pressure of 70 bar across the valve. The same applies for testing the DHSV. As calculated in Chapter 4.1.1, a volume of 58.45 litres must be pumped in above the DHSV in order to equalize the differential pressure before the valve is opened. Thus, 58.45 litres must be bleed off in order to equalize the 70 bar differential pressure across the valve. A differential pressure down to 30 bar is considered as sufficient test pressure, meaning that less than half of the calculated volume could be bleed off. Because the volumes are so small, a solution is to bleed off the volume directly to sea.

4.4.3 Annular Pressure Control

The annular pressure on CO_2 injection wells will experience pressure changes similar to those experienced on water injection wells. It is expected that the temperature of the injected CO_2 is lower than the surroundings, resulting in a reduction in volume of the packer fluid in Annulus A. The well will be especially vulnerable to temperature and pressure changes during start-up and shut-down of the well. Usually, as for water injection wells, CO_2 injection wells are supplied with CO_2 from topside or from shore. CO_2 injected on the Norwegian continental shelf are all supplied with CO_2 from the latter. The injection line is laid along the seabed over longer distances. With increasing length of the injection line, the temperature of the injected CO_2 will stabilize around the temperature of the sea, which is around 4°C in Norway. When injected into the reservoir, the CO_2 that are being injected will cool down the packer fluid located in Annulus A. The volume of the packer fluid will be significantly reduced, and a large refilling volume is needed.

For the Northern Light project, it is expected that the top of the well will have a temperature of 26 °C , that the reservoir temperature is approximately 100°C - 120 °C, and the temperature of the injected CO_2 is 6°C (Equinor, 2018a). Thus, a temperature difference of about 100°C is expected between the top of the well and the reservoir. The temperature of the packer fluid within Annulus A will be cooled by the injected CO_2, which will make the packer fluid in the annulus to contract.

4.4.4 Suggested Solutions

As described above, one of the biggest challenge on CO_2 injection wells is to control the pressure in Annulus A. To remove the service line, new solutions are required to perform the various functions enabled by the service line. The solutions presented below enables the annular pressure control without a service line, but does not make it possible to perform valve testing without the service line. The solutions were originally presented by Equinor (2019).

Nitrogen Pillow

The solution described in Chapter 4.3.4, with using nitrogen gas to control pressure changes in Annulus A, can be utilized on CO_2 injection wells too. By placing a nitrogen pillow on top of the well the gas will work as a pressure accumulator opposing the pressure changes experienced in Annulus A caused by temperature differences between the injected CO_2 and the surroundings. As previously discussed, a risk with the solution is that nitrogen can escape the system. The ability to control the pressure in Annulus A would in this case be lost.

The solution makes it possible to control the pressure in Annulus A, which is a severe task on CO_2 injetion wells. However, the solution does not enable testing of the valves on the Xmas tree or the DHSV without the service line. As suggested in Chapter 4.3.4, a pressure intensifier can be included in the solution. This will make it possible to perform valve testing on such wells without using the service line. However, the solution can only be applied on wells where hydrates are not expected to be an issue, as the solution dues not solve the problem with hydrates.

Subsea Accumulator Tank

Another solution making it possible to control the pressure within Annulus A without a service line on CO_2 injection wells, is to install a subsea accumulator tank on the Xmas tree. The system would not require a pump, as the pressure inside the accumulator would be the same as the surroundings. When the pressure in Annulus A is reduced, the fluid inside the subsea accumulator will refill the annulus, opposing the pressure change experienced in the annulus. The solution makes it possible to control the pressure in Annulus A, but, as the pressure in the subsea accumulator tank is equal to the pressure in the rest of the subsea system, the solution could not be used to create sufficient test pressure across the valves when testing the DHSV or the other valves on the Xmas tree. The subsea accumulator tank would not be able to build up pressure one one side of the valve nor bleeding off the pressure on the other side of the valve. The pressure could be bleed off to sea, but the feature of building up pressure on one side of the valve remains unsolved. Thus, the solution with a subsea accumulator tank must be combined with another solution in order to remove the service line.

As described in Chapter 4.1.5, the solution should include a pressure intensifier which would enable valve testing to be performed on such wells without using the service line. The configuration of the solution is illustrated in Figure 4.21. However, as for the ”Nitrogen Pillow”-solution, the solution does not solve the problem with hydrates. Thus, the solution could only be used on wells where hydrate formation is not expected unless other solutions that solve the problem of hydrates emerge.

Allowing Pressure Changes in Annulus A

When Annulus A experiences large temperature changes, the composition of the packer fluid contained within the annulus starts to change in response to this. On a CO_2 injection well, the packer fluid is cooled by the injected CO_2, causing some of the packer fluid to enter the gas phase which in turn causes Annulus A to be in underbalance compared to its surroundings. It is important to monitor the pressure in Annulus A at all times. With some of the packer fluid turning into gas, it is possible that the pressure sensor located in the annulus may monitor the pressure within the gas phase, resulting in incorrect pressure recordings in the annulus. However, the pressure sensor could be places further down in the annulus, ensuring that the montoring takes place within the liquid phase of the packer fluid. By placing the sensor further down in the annulus, one could allow changes of the packer fluid composition, and still be able to monitor the pressure in the annulus. By doing so, it is possible to detect inflow from the reservoir and be able to react thereafter without having to refill Annulus A by some fluid. With this solution, the casing and tubing that make up Annulus A must be designed to withstand the pressure change in the annulus.

As suggested in Chapter 4.3, a subsea tank and a subsea pump could be installed at the outlet of where the service line is connected to on today's subsea system. The solution makes it possible to both build up and bleed down the pressure when testing the valves on the Xmas tree and the DHSV. However, the tank must be of a certain size as the volume required to control the Annulus A pressure is large. Also, the tank must be refilled from time to time.

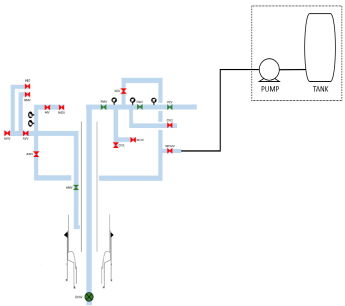
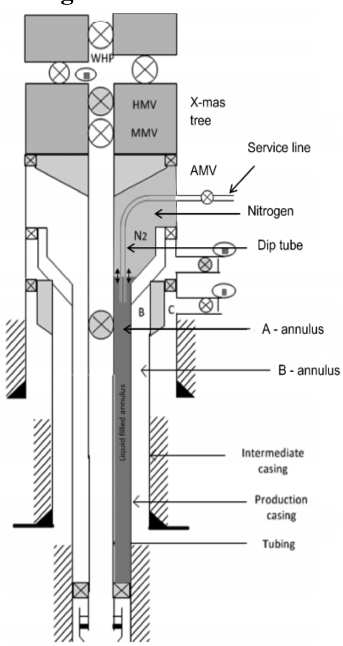
Both water and CO_2 injection wells will experience big pressure changes in Annulus A. The pressure changes can be reduced by using a different packer fluid than the one commonly used on today's subsea system. By using a packer fluid that responds less to temperature changes, large pressure changes within the annulus can be avoided. Also, the test procedures on both water and CO_2 injection wells are the same as for oil and gas producing wells. It is possible that testing of injection wells can be performed less frequently than on producing wells (Equinor, 2019). If so, less test fluid will be required in order to perform the various tasks on water and CO_2 injection wells. The required fluid could be supplied to the well by a vessel through a hub or similar. Still, the problem with hydrates on CO_2 injection wells remains unsolved and the solution can only be applied to wells where hydrate formation is not expected in order for the service line to be removed. As for the other solution, a subsea tank containing MEG/methanol can be installed close to the wellsite. If the two solutions mentioned above are implemented in the system, the size of the tank could be smaller than what is calculated for producing wells. Further calculation is required to determine the size of such a subsea tank.

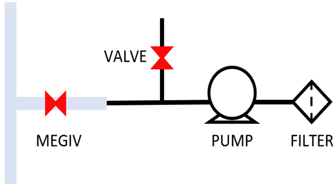
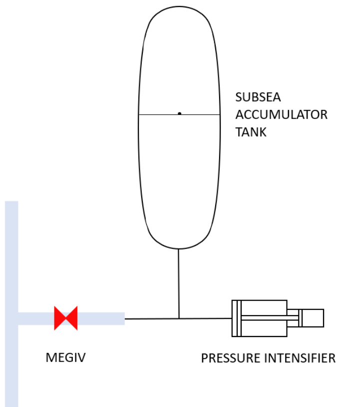
It is clear that in order to remove the service line on CO_2 injection wells, a combination of solutions are required. Further analysis regarding configuration, cost and more is needed to determine which solutions are best suited for CO_2 injection wells.

4.5 Solution Review

The various solutions for oil and gas producing wells and water and CO_2 injection wells are reviewed in Table 4.4. The solutions are further discussed in Chapter 5.

Table 4.4: Solution review for the different type of wells

Solutions	Oil Producing Wells	Gas Producing Wells	Water Injection Wells	CO_2 Injection Wells
Subsea Tank and Pump 	+	+	+	+
Nitrogen Pillow 	-	-	+	+

Using Seawater as Test Medium 	-	-	+	-
Subsea Accumulator + Pressure Intensifier 	-	-	+	+

Chapter 5

Discussion

The solutions presented in Table 4.4 are discussed in more detail in this chapter, focusing on the aspect of safety, carbon emissions and economics. The solutions are discussed and also compared to the service line solution commonly used on today's subsea system.

5.1 Subsea Systems with a Service Line

On today's subsea system, MEG or methanol is supplied to the well through the service line in the umbilical. The pressure in the service line must be above wellhead pressure to be able to inject into the Xmas tree. The pressure is usually ranging from about 500 bar-690 bar with exceptions (Equinor, 2019c). In the event of a leakage on topside on the host facility, personnel working near the leakage will be exposed to chemicals and potentially be injured.

Carbon emissions are low with the service line solution. Should a leakage occur, the potential leakage will occur on the deck at the host facility. After the leakage has occurred, the deck is flushed and spilled chemicals are collected. After collection, the chemicals are either treated offshore or shipped to shore where it is further processed before it is discharged.

Ideally on an all-electric submsea system, electric power and signals are supplied to the well by a DC/FO cable while chemicals are supplied by a separate injection flow line. Festøy and Lundal (2017) has conducted an economic analysis of how much such a methanol injection flowline costs. The economic analysis include material selection, installation and maintenance cost of a methanol injection flowline. In the calculations performed, the diameter of the service line is set to 6 inches and the length of the flowline is set to 30 km. Festøy and Lundal (2017) considered carbon steel, UNS S31600 authentic stainless steel and UNS S32205 duplex stainless steel as suitable materials for the flowline. With focus on choosing a material that intersect technical suitability with economic feasibility, it was concluded that carbon steel is the best material option for the injection flowline.

According to Festøy and Lundal (2017), the flowline will have a total life cycle cost of \$14730610, corresponding to NOK 132.5 million. The calculations are based on experience retrieved from the Industry Cost Database. Calculations performed by Peyrony and Beaudonnet (2014) shows that when comparing the classical layout with a service line in the umbilical with subsea chemical storage, it becomes profitable to store chemical subsea after exceeding a tie-back length of 24 km.

5.2 Subsea Tank and Pump

A solution enabling the removal of the service line on producing and injecting wells, is to store MEG/methanol in a subsea tank close to the wellsite. A pump is installed close to the tank in order to supply MEG/methanol to the well when needed. The pump is also required in order to create sufficient test pressure when leakage testing the valves on the Xmas tree and the DHSV and when controlling the annular pressure. It is assumed that the umbilical is replaced by a DC/FO cable with this solution.

The safety aspect of this solution is considered improved when compared to the solution with a service line. Should a leakage occur, this will harm the environment and not personnel working on the field as the storage of chemicals take place at the seabed. However, a leakage is more difficult to discover with this solution. An undiscovered leakage will increase the emissions to sea.

A subsea chemical storage tank will most likely be of such a size that it does not fit inside a template structure, thus a stand alone structure must be designed. The structure must include a protection frame which provides protection against dropped objects and trawlers. The design of such a structure is expensive, increasing CAPEX with the solution. However, the structure makes it easier for module retrieval, refilling of the tank etc. CAPEX with this solution is also related to the cost of the subsea tank and the pump itself. OPEX is related to refilling of chemicals to the subsea tank and how often the pump must be replaced. It is assumed that the pump is designed with a life time of 25 years. However, pumps are usually replaced after 5-10 years in operation due to wear and corrosion. How often the pump must be replaced will depend on how many working hours the pump must run. Valve testing is performed a few times per year, and the annular pressure is expected to change during start-up and shut-down of the well. Thus, the pump is not running constantly which in turn means that the pump can most likely be changed less frequently. Also, as the valve test interval is decided by regulations, one will always know when next testing are to be performed. This makes it possible to replace the pump when other standard interventions are performed, thus reducing OPEX with the solution. It is assumed that the operation can be performed by an IMR vessel. Also, there is no need to shut down the other operations performed on the well during the replacement of the pump. Thus, no downtime of the rig is expected when the pump is replaced.

Main operational cost are related to refilling the subsea tank when the amount of MEG /methanol becomes too low. The subsea tank can be refilled by a vessel where chemicals are supplied to the subsea tank through a hub or by replacing the empty tank with a new one. Certain limitations regarding the size of the tank are set in order for the solution to be considered profitable. Calculation performed by Peyrony and Beaudonnet (2014) shows that OPEX is lowest when the subsea tank is replaced rather than refilled. This will obviously be determined by the size of the subsea tank and how often it must be refilled/replaced.

The calculations performed in Chapter 4 shows that a fluid volume of 0.73 m^3 is required for an oil producing well and 4.57 m^3 for a gas producing well in order to perform valve testing and annular pressure control. For the same design to be valid on both type of production wells, 4.57 m^3 is used further. Valve testing is performed every month the first three months of operation, and with good result the test interval is extended to every 3rd and every 6th month. It is assumed that the tank is refilled by the same vessel as the one replacing the pump, during the same operation. Thus, the tank is refilled every 5th-10th year. By assuming good test results, valve testing is performed six times the first year and two times the following years. Hence, by refilling the tank every 5th to 10th year, the size of the tank must be designed in the range of 59 m^3-105 m^3. A tank of this size will require a large footprint of the seabed.

However, Peyrony and Beaudonnet (2014) has concluded that a suitable size for a subsea chemical storage tank is 30 m^3. Thus, based on the calculations performed in this thesis, the tank must be refilled every 9th month. This increases OPEX and challenge the profitable aspect of the solution. Costs of the refill operation is determined based on vessel mobilization, vessel demobilization, transit to and from field and the refilling operation itself. The refilling operation can be performed by an IMR vessel which usually have a day rate of about NOK 1 million (Fuglestad, 2019). However, this is a rough estimate, and prices will depend on the contract between the service company performing the operation and the operating company. The pumps installed on an IMR vessel usually have a flow rate of 1000-1500 l/min and the tank will be refilled in 1-2 hours depending on the equipment available (Fuglestad, 2019). Depending on transit distance, the operation can take 1-3 days, meaning that OPEX will be ranging from 1-3 million every 9th month. If the tank is replaced rather than refilled, the operation must be performed by a larger construction vessel. The operation becomes less flexible as it will depend on factors like vessel availability and suitable weather conditions. Similar work is, according to Fuglestad (2019), often scheduled for the summer season. As a comparison, deployment and retrieval of down lines can be performed at weather conditions up to 4-4.5m. Planning and execution of a tank refilling can therefor be performed most part of the year and thus be treated schedule-wise as other standard interventions, such as scale treatments (Fuglestad, 2019).

As previously discussed, test procedures for water and CO_2 injection wells could be challenged, so that testing can be performed less frequently. This allows the design of the tank to be smaller than the one purposed above. With a smaller tank, the refilling/replacement of the tank will occur less frequently, thus reducing OPEX for this type of wells.

Due to the lack of certain numbers, it is difficult to compare the cost of this solution with the classic solution with a service line. It is also difficult to confirm whether this will be a profitable solution for subsea production and injection wells. However, if the tank is refilled by an IMR vessel every 9th months, the solution is expected to be more profitable than the service line solution when the field exceeds a certain tie-back length. Peyrony and Beaudonnet (2014) has calculated the distance to be 24 km. But, further calculations are required, including parameters such as development of standalone structure, refill methods and installation costs with more in order to confirm the profitability of the solution.

5.3 Nitrogen Pillow

The ”Nitrogen Pillow” solution is suitable for wells where hydrates are not expected to be an issue. With this solution, annular pressure control is provided by nitrogen gas placed at the top of the well. Valve testing is performed by a pressure intensifier or with MEG/methanol stored in a subsea tank near the wellsite.

CAPEX with the ”Nitrogen Pillow” solution is related to the cost of the dip tube and the nitrogen gas initially placed at the top of the well. It also depends on which option the ”Nitrogen Pillow” solution is combined with. By including a pressure intensifier, CAPEX must include the cost of this component. A pressure intensifier is a small component that does not need a high pump capacity as the flow rate required is low. By combining the solution with a subsea tank, the subsea tank can be about half the size as the one described in the previous chapter since annular pressure control is provided by the nitrogen pillow. However, the combination of these two will require higher costs than dumping the solution with nitrogen and installing a subsea tank of the size described above instead. Such a subsea tank can be utilized in both annular pressure control and valve testing. Thus, a pressure intensifier is added to the solution and not a subsea tank.

A risk with the ”Nitrogen Pillow” solution is that nitrogen can escape the system even though a dip tube is installed to prevent nitrogen from escaping when AMV is opened. Also, the AMV may leak. For both scenarios, nitrogen must be refilled in order to continue annular pressure control. There are several methods for refilling nitrogen. Both CAPEX and OPEX are determined by the refilling method used.

Nitrogen can be refilled through a hub installed on the Xmas tree, where nitrogen is supplied to the well by a flowline connected to a vessel. A similar method is the hose-based filling method. This method employs a hose, which is lowered from a vessel for transferring fluids to the seabed. On board, the hose is stored on a large winch, and nitrogen is transferred from a storage tank into the hose via a rotary coupling (Equinor, 2014). The trickle charge method is another method, where nitrogen is supplied to the well from a central storage tank or a reservoir. If available, an existing supply line is used to provided to charge from the tank/reservoir to the well. Nitrogen can also be stored in a transfer container that can be lowered and retrieved to and from seabed by a vessel crane (Equinor, 2014). The presented refilling methods are also applicable for refilling a MEG/methanol containing subsea tank.

The trickle charge method is convenient if refilling are required frequently or if several injection wells with the ”Nitrogen Pillow” solution are located close to each other and nitrogen is distributed out to refill several wells. The other solutions are considered more convenient when refilling are required less frequently. However, for the ”Nitrogen Pillow” solution to be profitable, the system must be designed so that the chance of nitrogen escaping the system is low. Thus, it is not expected that nitrogen gas must be refilled frequently. For the hub and vessel method and the hose-based filling method, it is assumed that the operation can be performed by an IMR vessel, while the transfer of a container must most likely be performed by a larger construction vessel. This makes the method less flexible, as the availability of such a vessel is lower than an IMR vessel. Thus, it is expected that the hub and vessel method together with the hose-based filling method are the best options for a well with the ”Nitrogen Pillow”-solution.

The safety aspect of the ”Nitrogen Pillow”-solution depends on which method used to refill nitrogen. However, all the methods described uses a vessel when refilling. Since everything is moving on a vessel, the safety of personnel on a vessel is lower compared to a platform. Thus, by comparing the solution with the classic solution including a service line, the safety is considered reduced with the ”Nitrogen Pillow”-solution. There are more accidents on a vessel than on a fixed installation. This is due to difficult weather and such. Emissions with the concerning solution is considered low. A potential leakage would be nitrogen, which would go directly to sea. This is not considered an issue as it is expected that the emissions to sea will be low.

The ”Nitrogen Pillow”-solution is convenient for wells where hydrates are not considered an issue, as the solution lack an alternative to solve the problem with hydrates. To solve the problem with hydrates, one could replace the packer fluid commonly used today with a packer fluid that responds less to temperature changes. The injection well testing procedures can also be challenged by extending the test interval requirements for such wells. By combining the two alternatives with the ”Nitrogen Pillow” solution and a pressure intensifier, the required volume of MEG/methanol needed to perform the various tasks performed by the service line with today’s system is significantly reduced. An subsea tank can be installed near the well site for the sole purpose of solving the problem of hydrates. The size of such a tank would be much smaller than the one calculated for producing wells.

As for the previous solution, due to the lack of certain numbers, it is difficult to compare the cost of this solution with the classic solution with a service line. It is also difficult to confirm whether this will be a profitable solution for subsea production and injection wells. However, further analysis concerning system design, costs and more are required to confirm the profitability, and thus the potential, of the solution.

5.4 Using Seawater as Test Medium

Using seawater as test medium is considered a convenient solution for water injection wells where gas migration into the well is not expected. By using seawater as test medium rather than MEG/methanol, the requirements defined as ”service line requirements” can be performed without using the service line. The solution includes a pumps, filter and a bypass valve which are installed where the service line enters the Xmas tree on today's subsea system.

The safety aspect of this solution is considered improved compared to the solution with a service line. The pump is installed subsea where no personnel is exposed to the solution during operation. However, by installing a pump where the service line enters the Xmas tree on today's subsea system, a leakage point is created. In case of a leakage, emissions to sea are increased.

When using seawater as test medium, the pump included in this solution must be able to operate in and with seawater. Such a pump does not exists and both testing and modifications are required in order to develop a qualified pump. Thus, CAPEX will depend on the development of the seawater pump. According to Equinor (2019c), a verification of such a pump will cost around NOK 5 million. In addition, the cost of the pump itself and installation costs must be included in CAPEX for this solution. OPEX will depend on how often the pump needs to be replaced. Since the pump is working with seawater, corrosion may occur and the pump must most likely be replaced more frequently than a pump working with a less corrosive fluid.

A prerequisite with the solution is that the pump, filter and bypass valve can be placed inside a template as retrievable units. It is assumed that the pump will be of the size 1m x 1m x 1m. Therefore, placing the unit inside a template with a standard size of 4.5 m x 10.8 m will most likely be possible (Equinor, 2019c). The unit must be designed and placed in such a manner that it can easily be replaced by a standard IMR vessel. As previously assumed, such vessels have a day rate of about NOK 1 million. As for the subsea tank and pump solution, the operation costs with an IMR vessel will be determined by vessel mobilization, demobilization, transit to and from the field and the operation itself. Availability is not considered an issue if an IMR vessel is utilized.

For water injection wells where gas migration into the well is not expected, using seawater as test medium is considered a suitable solution. The development, installation and maintenance of the pump, filter and bypass valve is not expected to be expensive. The solution is also simple and cheap compared to the classic solution with a service line, thus having a cost saving potential compared to the classic solution. However, as for the other solutions, it is difficult to confirm whether this is a profitable solution or not compared to the service line solution due to the lack of certain numbers.

What is certain is that for the solution to be profitable, it must be applied to wells on a template where all wells on the template are injection wells. For instance, if a four-slot template consist of two water injection wells and two production wells, and the production wells are provided with MEG/methanol by the service line, the potential cost savings made possible by using seawater as test medium on the water injection wells, and thus enabling the removal of the service line on these two wells, are gone. The solution will have the greatest cost-saving potential if used on a template where all wells are water injecting wells. As for the other solutions, further analysis concerning system design, costs and more are required to confirm the potential of the solution.

5.5 Subsea Accumulator Tank and Pressure Intensifier

The solution with a subsea accumulator tank and a pressure intensifier is suitable for wells where hydrates are not considered an issue. The subsea accumulator tank will provide annular pressure control while the pressure intensifier will make it possible to perform valve testing without a service line.

The solution is similar to the ”Nitrogen Pillow”- solution but with this solution the pressure accumulator is placed outside the well rather than inside as the nitrogen gas in the ”Nitrogen Pillow”-solution. Thus, both the safety and emission aspect is considered the same for both solutions.

CAPEX with a subsea accumulator tank and a pressure intensifier is related to the cost of the tank and the pressure intensifier itself. It is expected that the tank will be of such a design that it can be placed within a template, thus not requiring any trawling protection. If leakage of the tank occurs, the tank are refilled in the same way as described for the ”Nitrogen Pillow”-solution, which will determine OPEX for the solution. With the pressure accumulator tank placed outside the well rather than inside of the wells as for the ”Nitrogen Pillow”-solution, the tank is considered more accessible with this solution. Therefore, OPEX is expected to be lower for this solution compared to the ”Nitrogen Pillow” solution should accessing the tank be necessary.

As for the ”Nitrogen Pillow” solution, the solution with a subsea accumulator tank and a pressure intensifier lack an alternative to solve the problem with hydrates. However, a smaller subsea tank can be stored close to the wellsite for the sole purpose of solving the problem with hydrates. This will make it possible to use the solution on wells where hydrates are expected and thus enable removal of the service line on such wells as well.

When comparing the solution with the classic solution with a service line, it is difficult to confirm whether it is a profitable solution or not, as exact numbers are missing. Further analysis concerning system design and cost with more are required in order to do so. However, with the classic solution, MEG/methanol is provided to the field continuously and can be used whenever needed. But, if chemicals are only needed at regular intervals it may be convenient to utilize a solution like a subsea accumulator tank and a pressure intensifier. In order for the solution to be at all compatible with the classic solution, the alternative solution must show a high degree of flexibility, in addition to being profitable. This applies to all the suggested solutions. Potential cost savings made possible by the alternative solution can easily be consumed by other operating costs if the solution shows a lack of flexibility. This would in turn reduce the potential of the alternative solution.

5.6 Further Work

Calculations regarding the volume of test fluid are in this thesis calculated separately for oil and gas producing wells. Since most wells produce a combination of these two, future calculations should include a combination of these two.

Future calculations should be performed on the size of a subsea tank suitable for injection wells where hydrates are expected to form within the subsea system. The calculations should take into account that the test procedures have potentially been changed and that a packer fluid that response less to temperature changes has been utilized. Also, the implementation of either the Nitrogen Pillow solution or the subsea accumulator tank solution should be considered.

To determine whether the proposed solutions have potential or not, a specific field should have been selected and the solutions should have been evaluated against conditions on that specific field. This would have concertized the work, and should be included in further work on this topic.

As this thesis is a feasibility study, the solutions presented must be studied further to confirm whether the solution has potential or not when compared to the solution utilized today. Further analysis should include more specific costs calculations, material specifications and system design specifications among more. A similar analysis regarding today's solution with the service line should also be conducted. The results of the analyzes should be compared to reveal the potential of the various solutions.

Chapter 6

Conclusion

The objective of this Master thesis has been to identify which tasks the service line is used for and to investigate whether it is possible to perform these tasks without the service line. Challenges arises when removing the service line on oil producing wells, gas producing wells, water injection wells and CO_2 injection wells have been specified and investigated. Solutions overcoming these challenges on the different types of wells have been presented and discussed. Important findings are listed below.

- It was discovered that the supply of MEG/methanol cannot be eliminated completely on oil and gas producing wells, as these wells will experience hydrate formation as long as the system is kept under certain pressure and temperature conditions. A subsea tank and a pump can be installed close to wellsite, so that MEG/methanol can be provided to the well when needed. This will allow the service line to be removed on oil and gas producing wells.

- The volume of MEG/methanol required to test the DHSV, test the valves on the Xmas tree and to control the pressure changes experienced in Annulus A has been calculated. A fluid volume of 0.731 m^3 is required on an oil producing wells while a volume of 4.57m^3 is required on a gas producing wells. This is for the various tasks to be performed once.

- The size of the subsea tank will be determined by how often the tank must be refilled. If the tank is refilled every 5^{th}-10^{th} year, the tank must be of a size ranging from 59m^3-105m^3. A tank of this size will require a large footprint on the seabed. The tank can also be replaced, but the size of the tank must be such that the replacement can be carried out by an IMR vessel in order for the solution to be flexible.

- Seawater cannot be used as a test medium on oil and gas producing wells, as this will increase the chance of getting hydrates and scale within the subsea system. Hydrate formation is also expected on CO_2 injecting wells if seawater is used as a test medium. However, seawater can be used as test medium on water injection wells that inject into an active aquifer. The chances of gas migrating into the system are lower on such wells, and hydrates are therefor not considered an issue. If seawater is used as a test medium on water injection wells that inject formation water, scale may form. It was discovered that these precipitations are low and thus not considered a problem.

- If seawater is used as test medium on water injection wells, a pump, filter and a bypass valve can be installed where the service line enters the Xmas tree on today's subsea system. Thus, no changes to the Xmas tree design with implementation of this solution are required.

- Both water and CO_2 injection wells will experience big pressure changes within Annulus A. This can be controlled by placing nitrogen gas on top of the well. The nitrogen gas will expand/contract in response to the pressure changes experienced in the annulus caused by temperature changes in the injection string. A subsea accumulator tank can also be installed on the Xmas tree in order to control pressure changes in Annulus A.

- It was discovered that if pressure changes in Annulus A is controlled by nitrogen gas or a subsea accumulator tank, a pressure intensifier must be included in the solution for valve testing to be performed on such wells.

- It has proved difficult to remove the service line on water and CO_2 injection wells were hydrates are expected to form within the system. Further investigation on how to solve the problem with hydrates are required in order to remove the service line on such wells.

- In order for the proposed solutions to be compatible with the service line solution, which supplies the wells with MEG/methanol continuously, it is important that the solutions are both profitable and flexible. Future analysis should include thorough system design and cost calculations among more.

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