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A Study of a Subsea Chemicals Storage & Injection-Station

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Preface

This is a Master's thesis by Sigurd van Dijk Festøy and Vegard Lundal written at the Norwegian University of Science and Technology at the Department of Geoscience and Petroleum. The thesis concludes our 2-year Master's Program in Subsea Technology at the Department of Mechanical and Industrial Engineering.

It has been a demanding and challenging thesis to conduct. Lack of previous work on the topic has been a challenge, but it has been an inspiring and interesting experience. During this semester, both of us have had a steep learning curve in the field of Subsea Technology. By good teamwork we can say that we are pleased with our findings.

Trondheim, June 11, 2017

Sigurd van Dijk Festøy

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Acknowledgements

We would like to thank our supervisor Professor Tor Berge Gjersvik for his excellent guidance and help throughout the thesis. We would also like to express our gratitude to Even Kallevik for his proofreadings.

Summary

Total and Doris have announced that they want to challenge the way of thinking of how to supply subsea field developments with chemicals. With a Subsea Chemicals Storage & Injection-station (SCS&I) the chemicals are injected much closer to their injection points compared to a conventional solution, where they are injected from a topside facility. This reduces the response time of hydrate inhibitors which leads to a shorter well shutdown/start-up operation. Also, dosing of production chemicals can be done more accurately, and valuable space topside is made available for other equipment.

This thesis challenges some of the design solutions proposed by Total and Doris for the SCS&I-station. The main topics investigated in this thesis are; total storage volume and tank design, system architecture, distribution schematics and an economic assessment of the SCS&I-station.

The research method used in this thesis is Concept Scoring. This research method enables screening of several concepts, and singles out the most suited concept for its designated application. Preferred architecture systems of the SCS&I-station and pressure-balanced tank design was found by applying this Concept Scoring. It was concluded that the best suited pressure-balanced tank design was the bladder tank. Interestingly, this deviates from the piston tank design proposed by Total and Doris.

It was found that methanol occupies approximately 60% of the total storage tank volume of the SCS&I-station. This means that the impact methanol has on the total storage capacity required is large. The economic assessment indicated that a solution with methanol stored and injected topside is more beneficial compared to a subsea storage solution.

Sammendrag

Total og Doris har annonsert at de vil utfordre tankegangen om hvordan kjemikalier tilføres undervannsfeltutviklinger. Ved en kjemikalielagrings- og injeksjonsstasjon under vann (SCS&I), vil kjemikalier bli injisert nærmere injeksjonspunktene sammenlignet med en konvensjonell løsning, hvor de blir injisert fra overflatefasiliteten. Dette reduserer responstiden til hydratinhibitorene, og fører til at tiden det tar for en nedstengings-/oppstartsoperasjon reduseres. Doseringen av produksjonskjemikalier vil også kunne gjøres mer nøyaktig, og verdifull lagringsplass på overflatefasiliteten blir frigjort til annet utstyr.

Denne oppgaven utfordrer noen av designløsningene som er foreslått av Total og Doris for SCS&I-stasjonen. Hovedelementene som blir undersøkt i denne oppgaven er; totalt lagringsvolum og tilhørende tank design, systemarkitektur, distribusjonsskjematikk og en økonomisk analyse av SCS&I-stasjonen.

Konsepscoring er brukt som forskningsmetode i denne oppgaven. Metoden går ut på at man kan filtrere ut flere konsepter, og deretter finne det mest passende konseptet for dets utpekte anvendelse. Foretrukne arkitektursystem av SCS&I-stasjonen og tankdesignløsninger ble funnet ved å benytte konsepscoring. Det ble blant annet konkludert med at et trykkbalansert blæretankdesign er mest hensiktsmessig, noe som avviker fra stempeltankløsningen som ble foreslått av Total og Doris.

Et annet funn, er at metanol okkuperer omtrent 60% av den totale lagringskapasiteten på SCS&I-stasjonen, noe som betyr at metanolbehovet i høy grad påvirker den totale lagringskapasiteten. Den økonomiske analysen indikerte at en løsning ved å lagre og injisere metanol fra overflatefasiliteten vil være økonomisk gunstig kontra å lagre det under vann.

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Abbreviations

Table 1: List of abbreviations.

Abbreviation	Description
AA	Anti Agglomerates
API	Americal Petroleum Institute
CAPEX	Capital Expenditure
CAT	Connector Actuation Tool
CSCC	Chloride Stress Corrosion Cracking
DEH	Direct Electrical Heating
DHSV	Down Hole Safety Valve
DSV	Diving Support Vessel
EPU	Electrical Power Unit
FPSO	Floating Production Storage and Offloading
HPHT	High Pressure High Temperature
HPU	Hydraulic Power Unit
HSE	Health Safety and Environment
HV	High Voltage
KHI	Kinetic Hydrate Inhibitor
LDHI	Low Dosage Hydrate Inhibitor
LNG	Liquified Natural Gas
MCS	Master Control Station
MEG	Monoethylene Glycol
Mn	Manganese
MPSV	Multi-Purpose Service Vessel
OPEX	Operational Expenditure
ROV	Remotely Operated Vehicle
SCM	Subsea Control Module
SCS&I	Subsea Chemicals Storage & Injection
SEM	Subsea Electronics Module
STABCON	Stab and Connect Connection System

Chapter 1

Introduction

In August 1859, the first oil was produced from a well by Edwin L. Drake. The oil was produced from a rather modest depth of 21 m with a rate of approximately 10 barrels per day (Dickey, 1959). The evolution of the Oil and Gas industry has been tremendous ever since. The Stones Field in the Gulf of Mexico has today the deepest subsea production system in the world. It lies on the seabed at a depth of approximately 2900 m. The reservoir the system is producing from lies on a depth of impressive 8077 m below sea level (Offshore Post, 2016).

While producing a subsea oil well today it must be injected with chemicals to ensure flow assurance. Production chemicals are injected at low rates into the wellflow at the X-mas tree and downhole to prevent corrosion, scale, emulsions, wax, etc. Hydrate inhibitors, such as methanol and Low Dosage Hydrate Inhibitor (LDHI), are injected to the well flow in the X-mas tree, manifold and downhole by high rates during shutdown and start-up in order to prevent hydrates to form and create blockages in the system. These chemicals are today stored and pumped from a topside facility through an umbilical to their injection points. When the tie-back distances from the topside facility to the wells increase, the umbilical will become larger, and more expensive to manufacture and deploy.

As a step to further reduce life cycle costs of subsea production systems, Total and Doris have announced that they want to develop a solution where chemicals are stored and injected from a Subsea Chemicals Storage & Injection-station (SCS&I) during production (Peyrony and Beaudonnet, 2014). As the tie-back distances increase, the costs by having an umbilical rises. Cost reductions are possible by having a SCS&I-station located near the subsea production system. Based on a design principle that the storage tanks are to be replaced every 6 months, Total and Doris have come up with a solution for an oil development case with four wells offshore West Africa.

1.1 Research Objectives

The main research objectives of this Master thesis are listed below:

- Estimate necessary SCS&I-station tank volumes with and without methanol storage based on a refill cycle of 6 months, using production data from a field case given by Total and Doris. Estimate the corresponding station size with and without methanol storage.

- Investigate and assess various alternative tank designs to the piston tank solution selected by Total and Doris. Special consideration should be given to the bladder tank as an alternative.

- Investigate and propose an alternative system architecture with dedicated tanks, pumps and accessories placed closer to each X-mas tree (4 off) and the manifold.

- Develop distribution schematics for the SCS&I-station that satisfies the functional specifications of the injection chemicals given.

- Conduct an analysis of the economic feasibility by storing methanol topside instead of subsea.

1.2 Limitations

Subsea field developments touches a broad variety of engineering related topics. The SCS&I-station is no exception, as it is a very complex and comprehensive structure. A detailed analysis of every sub-system and equipment is therefore impossible to consider due to time constraints and limited background knowledge. Limiting measures are therefore set in order to keep within reasonable and realistic aspirations. The following bulletins will not be considered in this thesis:

- The physical properties of equipment and components.

- The physical properties of the chemicals.

- Any communication with variable components or equipment such as chemical injection pumps, valves and monitoring devices.

- Design of structure foundation.

- The working principle of the Control and Distribution Unit at the SCS&I-station.

1.3 Structure of the Master Thesis

The structure of this thesis is as following:

- Chapter 2 concerns relevant theory for the SCS&I-station, and is meant to support the understanding of SCS&I-station related discussions in the following chapters. An introduction to the research method applied is also included.
- Chapter 3 presents results obtained in this thesis.
- Chapter 4 concerns discussions and uncertainties of the results obtained.
- Chapter 5 presents the main conclusions of the thesis.
- Chapter 6 includes improvement of existing work and recommendations for further work.

Chapter 2

Theory

This chapter presents relevant theory for the SCS&I-station. The following sections are meant to elaborate concepts relevant to the SCS&I-station and associated discussions. An introduction to the research method applied is also included.

2.1 Why Store and Inject Chemicals Subsea?

There are several reasons why it is of interest to store and inject chemicals subsea. As the complexity of a field increases, the umbilical will become larger, more complex, and more expensive to manufacture and deploy.

A subsea umbilical is used for different purposes. Some of its main functions are to provide power to the subsea installations, provide subsea well control, provide subsea manifold control and bring chemical inhibitors to the injection points (Bai and Bai, 2010a). Generally an umbilical consists of electrical cables, fibre-optic cables, hydraulic fluid lines and chemical injection lines. A cross-section of a typical umbilical is shown in Figure 2.1. Important factors that influences the cross section of the umbilical are injection flow rate of chemicals, number of hydraulic lines, injection pressure and tie-back length.

By storing chemicals subsea, toxic chemicals that may harm workers are removed, improving HSE conditions on the topside facility. Also, more space for other equipment will be made available as these storage tanks occupy a lot of space (Schroeder et al., 2016). Another positive feature is that the chemicals are stored much closer to their injection points compared to a standard topside solution. Meaning that the response time to inject chemicals are significantly reduced. For hydrate inhibitors, the shutdown/start-up operation time will decrease as they are located closer to their injection points. The probability of hydrate prevention failure will also decrease, as hydrate inhibitors are injected instantly. Production chemicals are injected at low rates, requiring accurate dosing of chemicals. By local injection, the chemical injection pumps can easily dose the required amount of production chemicals.

From the oil field development study done by Total and Doris, it was shown that from an economic point of view, the SCS&I-station solution is beneficial if tie-back lengths are longer than 24 km (Peyrony and Beaudonnet, 2014). This can be seen in Fig 2.2. This case study evaluates the SCS&I-station solution at a tie-back length of 30 km.

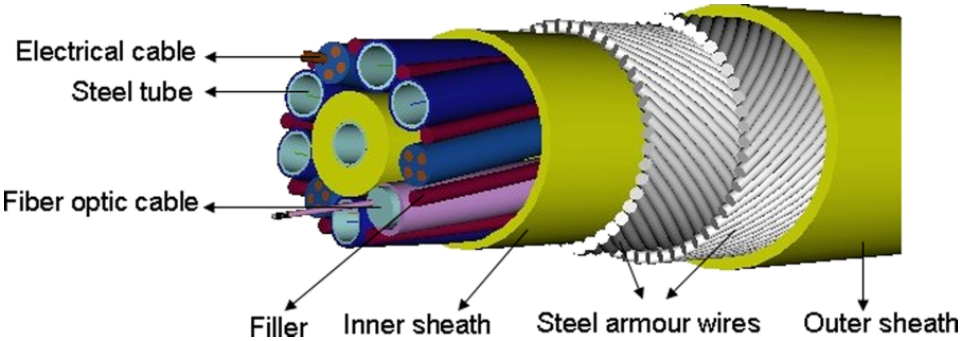

Figure 2.1: Cross-section of an umbilical (Lu et al., 2014).

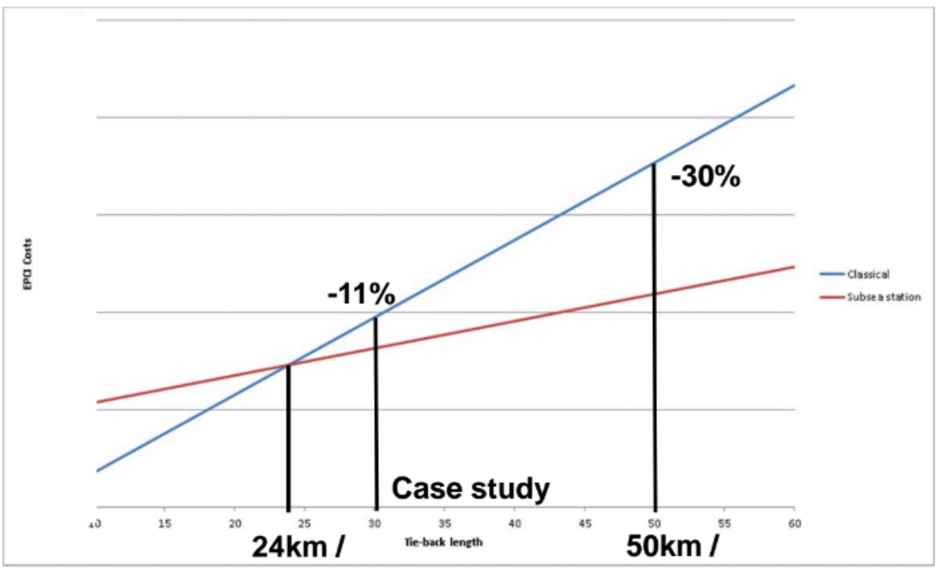

Figure 2.2: Differences in cost for an umbilical solution compared to a SCS&I-station (Peyrony and Beaudonnet, 2014).

2.2 Subsea Cost

Subsea costs can be divided into Capital Expenditure (CAPEX) and Operational Expenditure (OPEX) for a subsea field. CAPEX are funds used by a company to acquire or upgrade physical assets such as property, industrial buildings or equipment (Investopedia, 2017a). In a field development, these costs are processing facilities, subsea equipment and installation. OPEX is an expense a business incurs through its normal business operations (Investopedia, 2017b). During field operation, some of the associated expenses are maintenance, personnel salary, energy consumption and export of products.

As the Oil & Gas industry moves into more challenging environments, the costs associated by developing these projects increase due to higher temperatures, higher pressures, longer tie-backs and deeper waters. Among the key factors that influences subsea costs are (Bai and Bai, 2010b):

- Water depth
- Distance to existing infrastructure
- Characteristics of the reservoir
- Region of subsea development

Water depth: At considerable water depths, the external pressure that the subsea equipment will experience is of such magnitude that a robust design is needed. As the water depth increases, installation time of equipment will rise, increasing expenses of equipment installation.

Distance to existing infrastructure: As the tie-back distances increase from subsea field to host facility, increased pipeline and umbilical costs are inevitable.

Characteristics of the reservoir: Subsea equipment such as X-mas trees, manifolds and subsea separators must be designed according to a given reservoir's characteristics. For instance, if the reservoir is High Pressure and High Temperature (HPHT), the subsea equipment has to cope with the reservoir demands. Design and manufacturing costs may therefore increase.

Region of subsea development: If the subsea development is located in remote Arctic areas, the project becomes more difficult to execute due to environmental and infrastructural challenges. Ice ridges and the lack of existing infrastructure are typical issues encountered. Logistics of equipment, installation and robust design increases the field development costs.

2.3 The SCS&I-station

A Subsea Chemicals Storage & Injection-station (SCS&I), shown in Figure 2.3, is a proposed solution by Total and Doris to enable longer tie-backs of subsea developments. The main goal of a SCS&I-station is to store the various chemicals closer to the production facility than by conventional solutions. By local chemical storage and injection, there is no need for chemical lines in the umbilical. This enables a smaller umbilical cross-section to the subsea production facility (Peyrony and Beaudonnet, 2014).

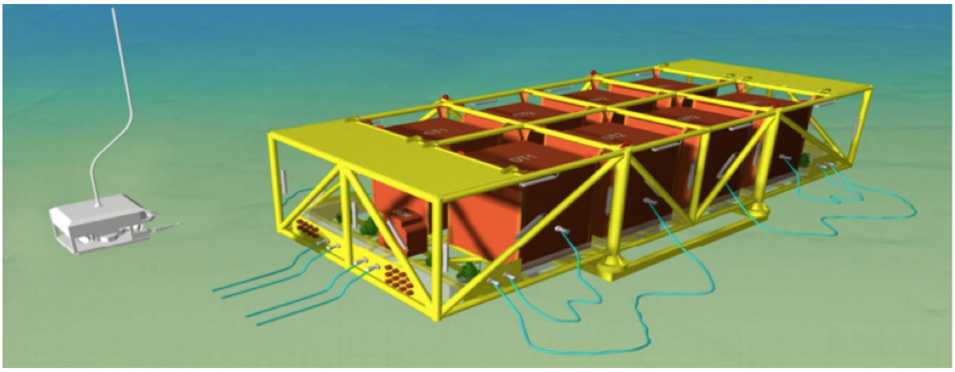

Figure 2.3: SCS&I-station (Peyrony and Beaudonnet, 2014).

The SCS&I-station main equipment and sub-systems are (Peyrony and Beaudonnet, 2014):

- Subsea chemical storage tanks
- All-electric control system
- Data transmission
- Chemical injection pump
- Pump control
- Flow control devices and monitoring
- Piping
- Subsea Control Module (SCM)
- Structure and foundation
- Valves

Only the main equipment and subsystems that are related to this thesis are presented in detail in Section 2.4.

The system uses an all-electric control system which eliminates the need for hydraulic lines in the umbilical. When the hydraulic and chemical lines are removed from the umbilical, the umbilical cost and complexity will decrease accordingly.

The production chemicals used in this oil field development are corrosion inhibitor, scale inhibitor, asphaltene inhibitor, biocide and demuslifier. They are typically injected at rates of 6 to 20 l/hr. Biocide is injected in batch mode 5 hrs/week at a rate of 180 l/hr (Beaudonnet et al., 2012). Methanol and LDHI are the hydrate inhibitors applied in this field development. Methanol is typically injected at 5000 to 25000 l/hr and LDHI is typically injected at levels of 0,25-5 vol% of the produced water (Clark et al., 2005).

Subsea chemical storage tanks are placed on tank modules. Each module contains four tanks in addition to equipment and functional systems. Each tank module has a total storing tank capacity of 30 m^3, which means that each subsea chemical storage tank stores 7,5 m^3. The modules cannot be heavier than 70 tons, since refill operations will be performed by a standard Multi-Purpose Service Vessel (MPSV) with 70 tons crane capacity. A SCS&I-station consist of several modules, where each module store and inject one specific chemical. To ease installation and retrieval, the modules are lowered into pre-built frameworks on the structure foundation, as shown in Figure 2.3. These frameworks prevent the modules from damaging each other during these operations, enabling them to be stored in close proximity to each other.

The refill operation of chemicals is done by tank module-change out (Peyrony and Beaudonnet, 2014). The SCS&I-station should be designed so that every 6 months, the tank modules on the SCS&I-station will be changed out with new ones. By having this requirement, it means that the subsea chemical storage tanks will be refilled ashore and then replaced subsea. This ensures thorough maintenance and inspection of the emptied tanks and other equipment, such as chemical injection pumps and monitoring systems. Since time is the most important factor to take into consideration in subsea field developments, the refill operations must be conducted relatively fast in order to be cost-efficient. The tank modules should be designed such that subsea chemical storage tanks, and other components, can be retrieved separately.

2.4 SCS&I-station Main Equipment and Subsystems

The SCS&I-station consist of several critical subsystems. Only the subsystems and main equipment that are related to this thesis are described in this section.

2.4.1 Subsea Chemical Storage Tanks

Five different tank proposals for the SCS&I-station will be described. A subsea chemical storage tank is used to store a required volume of chemicals. The chemical storage tanks used in this case are pressure-balanced. This means that the seawater outside the tank acts on the fluid inside the tank (Beaudonnet et al., 2012). Their functionalities, design and operability will be presented.

2.4.1.1 Piston Tank

A piston tank contains a piston that separates the two liquid zones (chemicals and seawater) inside the tank. Two elastomer seals are located on the piston. One seal for the chemical and the other for the seawater. The elastomer seals must be of a material that can withstand the chemicals stored, temperature and pressure effects applied. Since the piston is relatively wide, challenges arise with perfect movement of the piston. If it is not moving perfectly, the two pressure zones will not be separated, and leakage of chemicals may occur. The piston tank is also a heavy and robust construction. Figure 2.4 illustrates the functionality of the piston tank.

The material of the elastomer seals is affected by the temperature, but also what chemical is applied. Thus, the material of the elastomer seals must be selected to resist chemical attacks. In order to get sufficient sealing, temperature in the elastomer seal area must be taken into consideration to select the best suited material. Heat from friction, and swelling which results in more heat must also be taken into consideration since it may cause failure (Apple Rubber Products, 2016).

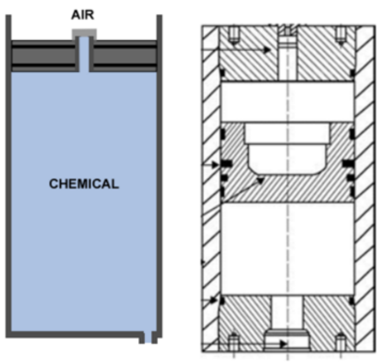

Figure 2.4: Piston tank (Peyrony and Beaudonnet, 2014).

2.4.1.2 Bladder Tank

Bladder tanks are collapsible bags that can contain chemicals. Depending on the density of the stored chemicals, the bags can collapse either up or down, shown in Figure 2.5. If methanol is stored, the bags will collapse up since methanol is lighter than seawater. If a chemical with higher density than seawater is stored, the bag will collapse downwards. The bladders and the structure around will together provide a two-barrier system. If there is a failure in the bladder and chemicals flow out, the structure will refuse leakage of chemicals (National Oilwell Varco, 2014). Sensors should be in place to monitor if a leakage appears. The bladders must be constructed so that the fabric, fittings and flanges can resist the chemical environment.

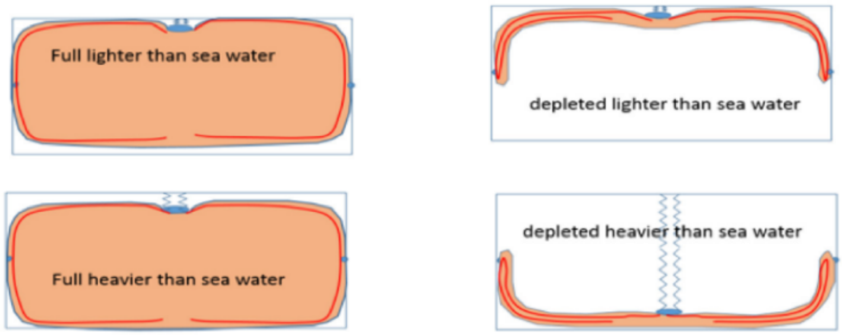

Figure 2.5: Bladder tank (Schroeder et al., 2016).

The bladder is always "touching" the chemicals, meaning that there is no area where vaporization can initiate (Sei Industries Ltd., 2016). Often, the bladder is made from a highly elastic rubber, such as butyl rubber (Flo-Dyne, 2013). Another positive feature of these tanks is that they are relatively cheap considering the volume they can store (National Oilwell Varco, 2014).

2.4.1.3 Membrane Tank

Membrane tanks are based on a membrane technology, preventing leakage to the surroundings, as shown in Figure 2.6. They are mostly used for Liquefied Natural Gas (LNG) storage. The materials that are used for this application must be able to keep the temperature extremely low. Normally, two types of membrane tanks are applied, which is the Membrane Full Integrity system and the 9% Ni Full Containment system (Ezzarhouni, 2013).

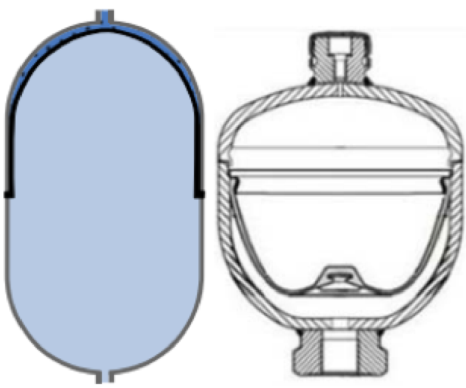

Figure 2.6: Membrane tank (Peyrony and Beaudonnet, 2014).

2.4.1.4 Rolling Tank

The rolling tank is based on a rolling diaphragm bladder technology. The rolling diaphragm bladder provides sufficient volume storage capacity while minimizing the external dimensions of the tank. The behavior of the bladder during chemical injection is illustrated in Figure 2.7. While chemical is pumped out of the tank, seawater will enter the tank via a dedicated line, shown in blue. The membrane will deflate as the chemical is pumped out of the tank structure. The tank structure surrounding the rolling diaphragm bladder, isolates the bladder from the environment. This is convenient in the event of a bladder leakage, avoiding environmental contamination.

In order to detect leakages, a safety system is installed to avoid environmental contamination. Also, in the event of bladder failure the same system can prevent seawater from being injected into the production flow (Chilloux et al., 2012).

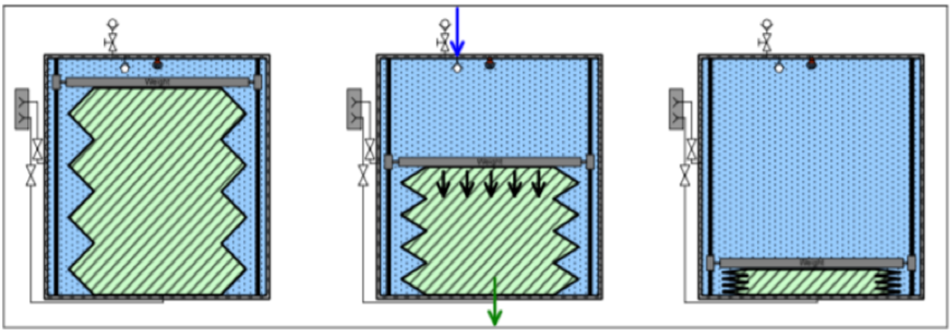

Figure 2.7: Rolling tank - bladder behavior during chemical injection (Chilloux et al., 2012).

2.4.1.5 Pillow Tank

Pillow tanks are large pillows fabricated of an elastic material. These elastic materials have been utilized in different industries, such as aerospace, defense and consumer products (Schroeder et al., 2016). The pillows will act very similar to the bladder in a bladder tank. When the chemical is extracted, the pillow will either collapse up or down depending on the density of the chemical. A challenge with the pillow tank is the large footprint they will have while laying at the seabed. A typical pillow tank is illustrated in Figure 2.8.

Figure 2.8: Pillow tank (Sei Industries Ltd., 2016).

2.4.2 All-Electric Control System

An all-electric control system means that the whole subsea production system is powered by electricity. Typically, an all-electric control system is applied on complex fields and marginal fields of long distances. In order to operate the subsea equipment, e.g. a valve, the Master Control Station (MCS) topside sends a signal to the Subsea Electronics Module (SEM). The SEM translates the coded message sent from the MCS and allows the necessary power to be transmitted to the valve from the topside Electrical Power Unit (EPU) for opening or closing (Bai and Bai, 2010c). Since no hydraulic control lines are required in an all-electric control system, the umbilical complexity and cost will be reduced. Other strengths and weaknesses of an all-electric control system to a conventional hydraulic control system, are listed below:

+ More applicable on HPHT (High Pressure High Temperature) fields due to removal of hydralic fluids.
+ Faster response time.
+ Better on complex fields, especially when new equipment are introduced to the system.
+ Long step out is not a problem.
+ No depth limitations.
+ Saves space topside as no HPU (Hydraulic Power Unit) is required.
+ Hydraulic fluid emission is prevented.
− Due to the complexity of the system, reliability is a challenge. Thus, redundancy must be built into the system.

2.4.3 Chemical Injection Pump

A pump is defined as a device that increases the level of energy in a liquid. There are two main groups of pumps; positive displacement pumps and dynamic pumps. Positive displacement pumps increase the pressure of the liquid by operating on a fixed volume in a confined space. Dynamic (centrifugal) pumps increase the pressure of the liquid by using rotary blades to increase fluid velocity. Positive displacement pumps can handle high viscosity, high pressures and low velocities better than centrifugal pumps. In addition, they can provide more accurate and constant flow (Forsthoffer, 2005). Generally, production chemicals are injected continuously with low rates, and high accuracy is required. Positive displacement pumps are therefore usually used for chemical injection.

To inject chemicals to their injection points, high reliability chemical injection pumps are required, Figure 2.9. A chemical injection pump should be designed and sized such that it can cover the peak injection demand (Standard Norge, 2010). As of today, no subsea chemical injection pumps exist. A possibility is to marinize existing topside chemical injection pumps or to adapt subsea pumps to this application. In order to marinize chemical injection pumps, some challenges needs to be addressed (Chilloux et al., 2012):

- Maintenance
  - When retrieving modules every 6 months, this could be done thoroughly.
- Size and weight
- Flowrate control
- Requirement of high voltage
- Water depth
  - External pressure act on the pumps
- Seawater environment
  - Corrosion and water ingress

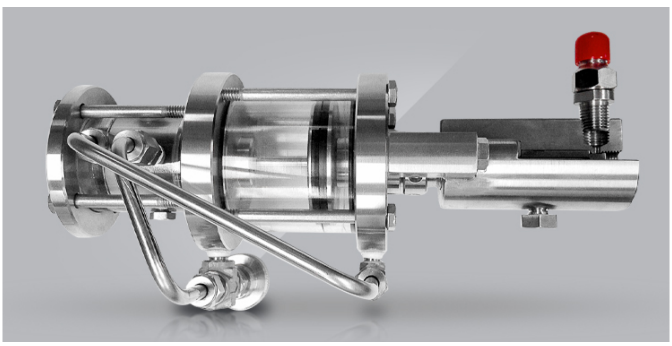

Figure 2.9: Chemical injection pump (Thomasmade, 2013).

2.4.4 Flow Control Devices and Monitoring

The information that the sensors are observing is transmitted from the SCMs to the topside MCS. Sensors that are typically a part of the subsea production system are (Bai and Bai, 2010c):

- Temperature sensors
- Pressure sensors
- Sand detectors
- Erosion detectors
- Pig detector
- Leak detection systems

Two examples of how monitoring can improve the SCS&I-system are presented below:

Condition monitoring is important in order to identify a significant change which is indicative of a developing fault. With condition monitoring one can observe the conditions of the equipment. Since the control system is all-electric, condition monitoring can be conducted.

To obtain the best performance and integrity of the production chemicals and hydrate inhibitors, monitoring is important. A water fraction meter should be installed at each well in order to measure the fraction of water in the production flow. This is important in order to decide the injection rates of the different chemicals.

2.4.5 Structure and Foundation

The SCS&I-station should be designed in a way that all equipment requiring maintenance and replacement are modularized. Proposals for structure foundation are presented.

2.4.5.1 Mud Mats

Mud mats provide a foundation for subsea equipment, as shown in Figure 2.10. According to the untrained shear strength of the soil and the supported equipment's loading conditions, a mud mat may vary in overall size and skirt depth to prove the bearing capacity of the subsea equipment. Mud mats are typically used when the soil is hard (Gjersvik, 2016)

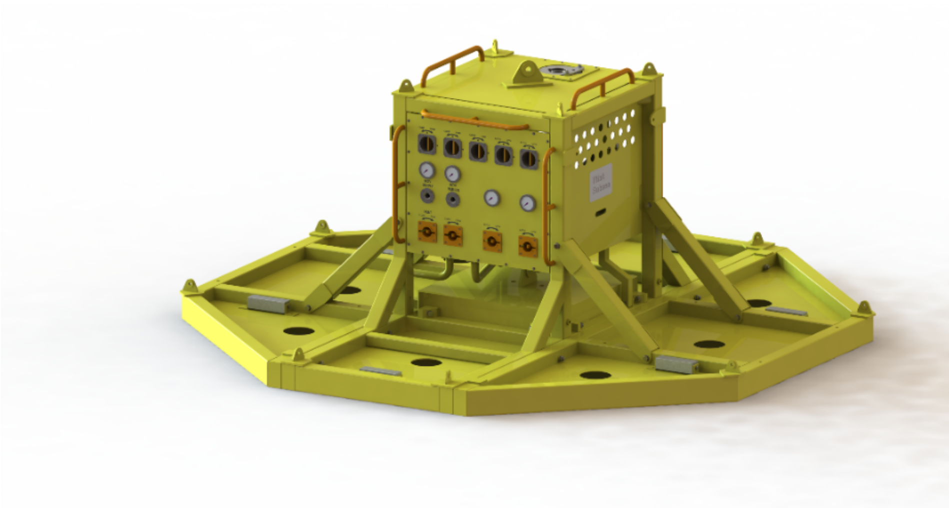

Figure 2.10: A subsea injection skid for pumping activities with mud mat as structure foundation (BRI Offshore, 2017).

2.4.5.2 Suction Anchors

A suction anchor is a gravity dominated structure, which uses suction to attach to the seabed. The suction anchor creates a smaller pressure beneath the anchor than the ambient pressure (Wang et al., 1978). In order to install the suction anchor to its final depth, it may require a pump to transport water from the inside of the anchor. Suction anchors are typically used for soft mudlines (Gjersvik, 2016). A suction anchor is shown in Figure 2.11.

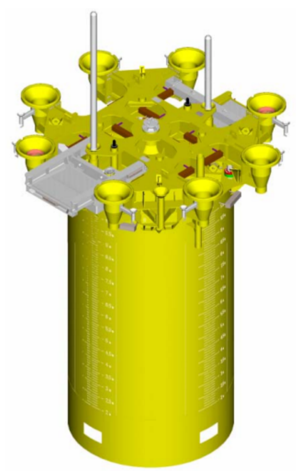

Figure 2.11: A suction anchor (Gjersvik, 2016).

2.4.6 Valves

A valve is a device that regulates the flow of a fluid by opening, closing or partially obstructing the passageway in which it is installed (Rennels and Hudson, 2012). In subsea applications, a valve is typically mounted within the piping system to control the production and injection fluids. The valve is controlled by devices called actuators. They can be electromechanical actuated such as an electric motor or solenoid, or hydraulic actuated powered by the pressure of a liquid such as oil or water. Every type of valve has its strengths and weaknesses. Some of the features to consider during valve selection are size, weight, height, speed of operation, seal wear, weldability, depth sensitivity, ROV intervention and fluid displacement during operation (Bai and Bai, 2010d).

2.4.6.1 Gate Valve

The working principle of a gate valve is that a gate, also known as wedge or disk, is moving directly into the fluid path stopping the flow of fluid. Metal-to-metal contact between the gate and the valve body provides sealing. The metal-to-metal contact is in a plane perpendicular to the flow path. A gate valve is shown in Figure 2.12, illustrating that the disk stops the flow when it is actuated. Gate valves are primarily used for on-off applications, that is fully open or fully closed. When the gate valve is in open position there is little restriction to the flowing fluid present, resulting in no pressure drop. This is considered to be the primary advantage of the gate valve. Common issues with gate valves are that they are susceptible to vibration when in a partially open position, and also prone to seat and disk wear. Large actuating forces are also needed to accommodate for the relatively large gate travel, resulting in large envelope or overall size (Rennels and Hudson, 2012).

In a subsea context, the valve can be either double acting or spring actuated. A double acting valve is when the valve actuator requires pressure to either open or close the valve. Spring actuated gate valves, however, need hydraulic power supply to either open or close the valve. An issue regarding subsea operations is valve response time when opening and closing. To ensure efficient response time the spring chamber acts as a potential energy source to assist in open or close functions of the valve (Systems safety, 2015).

2.4.6.2 Ball Valve

The ball valve consists of a spherical element with a cylindrical hole or port that allows straight through flow in the open position. They can be in fully open or fully closed position. The distinctive feature of the ball valve is that the port can have equivalent diameter as the connecting piping, meaning that the valve offers virtually no more pressure drop than the equivalent length of straight pipe. Figure 2.13 shows a ball valve where it is illustrated that the port has an equivalent diameter as the connecting pipes. Ball valves are used in on-off applications where low pressure drop and quick opening and closing are required (Rennels and Hudson, 2012).

2.4.6.3 Check Valve

A check valve is designed to close upon cessation or reversal of flow. Several closure devices exist for check valves, which can either be guided or spring assisted. Figure 2.14 illustrates a guided free-swinging disc. The disk is forced against an internal stop at full flow conditions to give the proper degree of opening. If reversal of flow occurs, the disk closes the valve (Rennels and Hudson, 2012). Usually, check valves are used as exhaust valves and in some cases to avoid hydraulic pressure loss from a hydraulic circuit, avoiding hydraulic back flow (Systems safety, 2015).

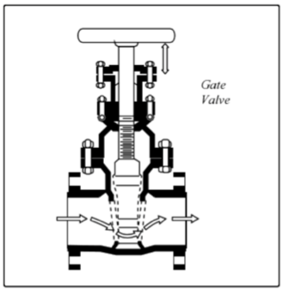

Figure 2.12: Working principle of a gate valve (Rennels and Hudson, 2012).

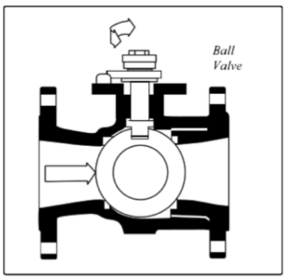

Figure 2.13: Working principle of a ball valve (Rennels and Hudson, 2012).

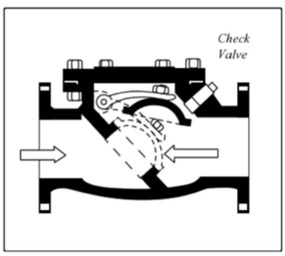

Figure 2.14: Working principle of a check valve (Rennels and Hudson, 2012).

2.4.6.4 Safety States of Safety Valves

In a Subsea Production System, it is of key importance to have reliable functional safety measures incorporated into the system. According to Systems safety (2015), the function of subsea safety valves is to "isolate or contribute to isolate the flow of hydrocarbons and other production fluids between a pre-determined zone". As illustrated in Figure 2.15, there are four different safe states depending on the type of configuration of the system and type of valve. For example, a gate valve may be configured to be fail safe close, fail safe open, or fail as is safe states. Common for all the safe states of a safety valve are the external power sources required to perform the desired function; hydraulic, electrically, and pneumatic. When a safety valve is fail safe close, it means that hydraulic control pressure or electromechanical power is needed to keep the valve open. If the line containing the control pressure is lost or a fault takes place, the valve will close to a safe state.

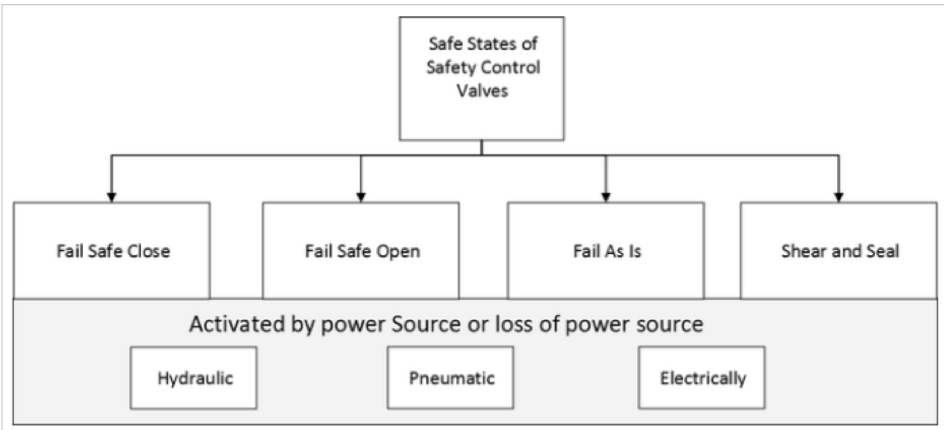

Figure 2.15: A safety hierarchy illustrating the safety states of safety control valves (Systems safety, 2015).

2.5 Flow Assurance Challenges

Flow assurance means to ensure successful and economic flow of hydrocarbons. This means that prevention methods to avoid formation of blockages and unstable flow along the pipeline must be executed. Typical flow assurance problems are hydrates, wax, scale, asphaltenes, emulsion and erosion (Bai and Bai, 2010e). Chemicals are normally injected in order to prevent such problems to occur. To get as good efficiency as possible of the different chemicals they are to be injected at the most optimum location. They can be injected through one point or several injection points in smaller doses. Different flow assurance challenges and how to prevent them with chemicals are presented below.

2.5.1 Hydrates

Hydrate is a solid that looks like ice. With a combination of water and light gas molecules (typically C1-C4), hydrates will form when the pressure is high and the temperature is relatively low. When hydrates are formed, they have the potential to block pipelines and other subsea equipment completely, and the production can not continue. They can also be hazardous to remove, making hydrate prevention important (MacDonald et al., 2006). Figure 2.16 shows a hydrate plug.

Figure 2.16: Hydrate plug (Chemoxy, 2016).

Prevention: Several prevention methods exists. The most common one is inhibition, either by thermodynamic inhibitors (methanol or MEG), Low Dosage Hydrate Inhibitors (Kinetic Hydrate Inhibitors (KHI) and Anti Agglomerates (AA)) or a combination of these. Other prevention methods are water removal, insulation of the system, direct electrical heating (DEH) and low pressure operation (Bai and Bai, 2010f).

Methanol and glycol are thermodynamic inhibitors. Similar to the use of antifreeze in a car engine, the thermodynamic inhibitors are lowering the hydration formation temperature of the fluid. Figure 2.17 shows the effect of a thermodynamic inhibitor, where methanol is used. If a higher wt% of methanol is used, the hydrate formation area is decreased, illustrated by the dotted lines. Thermodynamic inhibitors are generally injected at the subsea X-mas tree, manifold and downhole. This will prevent formation of hydrates in the choke and downhole during transient operations (Bai and Bai, 2010f)

Today, two types of LDHI exists, which is KHI and AA. KHI simply prevents hydrates to form for a period of time, while AA prevents the hydrate crystals to adhere to each other. LDHI should generally be injected at the Down Hole Safety Valve (DHSV) and manifold. Generally, methanol and LDHI should be injected at points where critical temperatures may be reached.

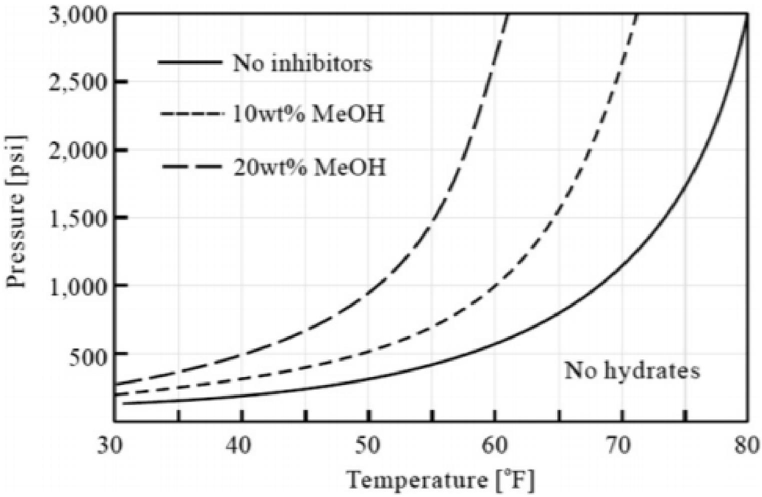

Figure 2.17: Methanol lowers the hydrate formation temperature. Hydrates are formed on the left side of the actual curve (Bai and Bai, 2010f).

2.5.2 Scale

Scale in oil production are mainly deposition of salts from the formation water as it experiences changes in pressure and temperature. The most common salts that are deposited are calcium carbonates ($CaCO_3$), barium sulfate ($BaSO_4$) and calcium sulfate ($CaSO_4 * 2H_2O$). Scale occur typically when a production well produces formation water together the hydrocarbons. Figure 2.18 shows a cut-out of a pipe cross-section with scale deposition. As illustrated, if prevention is not initiated the cross-sectional area of the pipe may be reduced.

Figure 2.18: Scale in a pipe (Bai and Bai, 2010g).

Prevention: To prevent scale occurrence, scale inhibitors are injected continuously into the production flow. Only small dosages of scale inhibitor is required to prevent scale occurrence for a period of time. The most common classes of scale inhibitors are; organic polymers, organic phosphonates, inorganic polyphosphates and organic phosphates esters (Bai and Bai, 2010g). The function of scale inhibitors is that they are delaying the growth of scale crystals. Hence, scale inhibitors should be injected to the system before scale precipitations initiates. Normally, scale precipitation affects the tubing. Scale inhibitors should therefore be injected downhole in front the the area where scale precipitation initiates (Poggesi et al., 2001). Scale inhibitors should also be injected at the X-mas tree in front of the choke valve in order to prevent scale precipitation in the pipelines, tree and manifold. (Bai and Bai, 2010g)

2.5.3 Emulsion

An emulsion is when two immiscible fluids are mixed together. When two fluid phases are present, emulsions may occur if the fluids are mixed and an emulsifier is present. An emulsifier is an agent that reduces the energy which is required to form an emulsion. In oil production, oil and water are present. Emulsions in oil production may be when droplets of water are dispersed in oil, or droplets of oil are dispersed in water. Emulsions in oil production should be avoided since it is challenging and costly to separate oil and water before the oil can be sold (PetroWiki, 2015b). Figure 2.19 illustrates a water-in-oil emulsion.

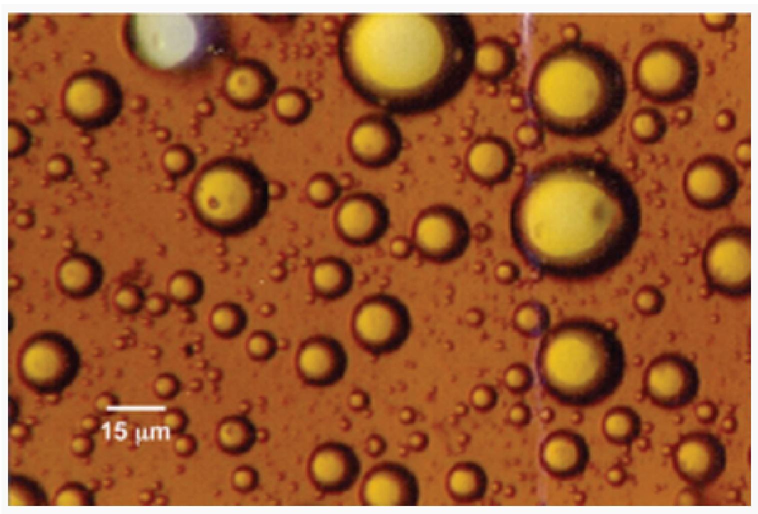

Figure 2.19: Water-in-oil emulsion (PetroWiki, 2015b).

Prevention: Demulsifiers are injected continuously into the production flow at low rates in order to break up the emulsions. Several types of demulsifiers exist, and it requires a lot of experience to choose the best suited for different production flows (PetroWiki, 2015a). Demulsifiers are normally injected into the production flow downhole and in the X-mas tree (Opawale et al., 2011).

2.5.4 Corrosion

Internal corrosion of wells and subsea equipment is a challenge. The production flow makes a corrosive environment since it contains CO_2, H_2S, water, chlorides and other corrosive agents. Depending of the substances in the production flow, different types of corrosion may take place. If the amount of CO_2 is large, sweet corrosion may be initiated. If the amount of H_2S is significant, sour corrosion may be initiated. Figure 2.20 shows internal corrosion of a pipe (Bai and Bai, 2010g). The internal corrosion can be of such magnitude that pipe leakage can be a result.

Figure 2.20: Internal corrosion of a pipe (Metropolitan Engineering Consulting and Forensics, 2016).

Prevention: To prevent internal corrosion of pipelines and subsea equipment, corrosion inhibitors are injected continuously at low rates. The inhibitor creates a protective layer at the pipe wall that prevents contact between the pipe wall and the corrosive environment. The inhibitor to be chosen depends on the composition of the production flow (Bai and Bai, 2010g). Corrosion problems can potentially be the main reason to tubing failure. To control downhole corrosion, corrosion inhibitors must be injected downhole (Smith and Pakalapati, 2004). Corrosion inhibitors should also be injected into the production flow at the X-mas tree (Bernt, 2004).

2.5.5 Wax

Wax are made up of long chained molecules that appears in crude oil. When the temperature drops below a critical point (cloud point) and the light molecules of the oil vaporizes, the waxes will crystallize. If this happens without having proper control the production will decrease with a worst-case scenario resulting in pipeline blockage. Other problems with wax deposition are increased viscosity and pipe roughness (Leontaritis and Leontaritis, 2003). Wax deposition in a pipe is illustrated in Figure 2.21

Figure 2.21: Wax build-up in an oil well (envirofluid, 2014).

Prevention: A few techniques of preventing wax appearance are applied today, among them are pigging, injection of inhibitor and thermal insulation. Pigging is the most used, since wax inhibitors are expensive and tend to be ineffective (Bai and Bai, 2010h). In this field development it is assumed that eventual wax problems can be handled by pigging.

2.5.6 Microbiological Contamination

When microorganisms grow in the crude oil, the hydrocarbon degrades and increased viscosity and density of the oil is a result. In addition, bacterial corrosion may occur on the equipment. Bacteria are a type of microbiological contamination, and they obtain energy from the crude oil to grow from the organic matter (Schlumberger, 1989).

Prevention: In order to cope with microbiological challenges, biocide is injected in batch modes into the production flow. Biocide kills the bacteria preventing bacteria to grow. Biocide should be injected before microbiological contamination can occur. Normally, biocide should be injected into the production flow downhole and at the X-mas tree.

2.5.7 Asphaltenes

Asphaltenes are a class of compounds in crude oil. They are large and complex molecules that originates from plants and animals. Asphaltenes are only a problem for the oil production when they are not stabilized (Bai and Bai, 2010h). Temperature, pressure and chemistry are important factors of the deposition of asphaltenes. For instance, it is great difference of the chemistry of the asphaltenes in the North Sea and the Gulf of Mexico. Figure 2.22 shows how pressure and temperature impact on the deposition of asphaltenes. Generally, asphaltenes do not create problems in the oil production because they are normally stable. If they however become unstable, valves, chokes and filters are susceptible.

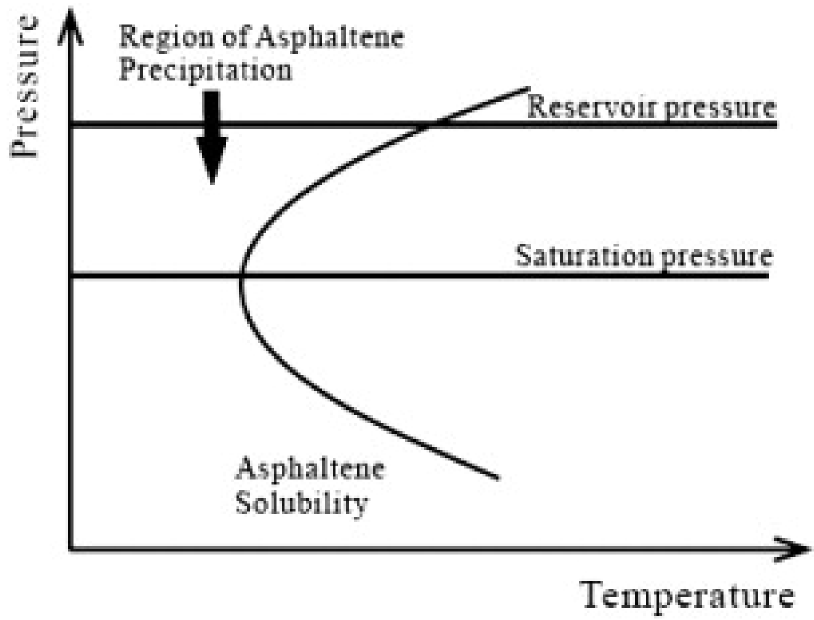

Figure 2.22: Asphaltene deposition as a function of temperature and pressure (Bai and Bai, 2010h).

Prevention: Chemical inhibitors can be utilized to prevent deposition of asphaltenes, which is driven by pressure. Hence, in order to preclude any pressure drop in the system, asphaltene inhibitors should be injected continuously as close to the perforations as possible (Willmon and Edwards, 2006). The inhibitor stabilizes asphaltene particles in the production flow by keeping agglomeration at a low level. To be effective, asphaltene inhibitors are normally injected at the production packer downhole (Bai and Bai, 2010h).

2.5.8 Chemical Injection Points

A summary of the injection points for the different chemicals used, are highlighted in Table 2.1.

Table 2.1: Injection points of the different chemicals.

Chemical	Injection points
Methanol	Downhole, X-mas tree, manifold
LDHI	DHSV, manifold
Asphaltene inhibitor	Production packer
Scale inhibitor	Downhole, X-mas tree
Corrosion inhibitor	Downhole, X-mas tree
Demulsifier	Downhole, X-mas tree
Biocide	Downhole, X-mas tree

2.6 Subsea Pipelines

There are several types of subsea pipelines. Some of them are; export pipelines, flowlines for chemical injection, flowlines for water injection, flowlines for transportation between platforms and subsea equipment, and multibore pipeline bundles (Bai and Bai, 2010i). Usually, these pipelines are either rigid or flexible. Rigid pipelines and flexible pipelines will be described shortly below.

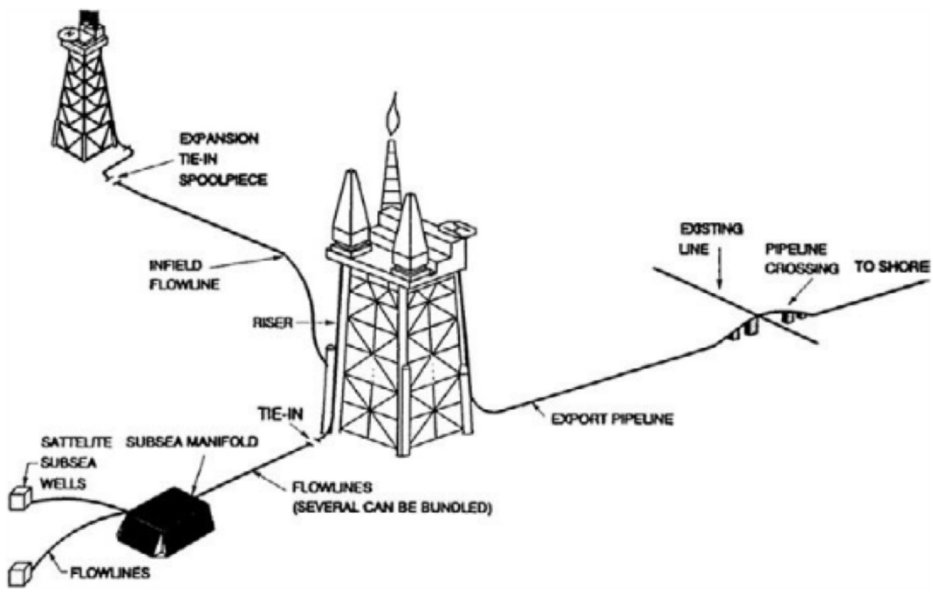

Figure 2.23: Application of subsea pipelines (Bai and Bai, 2010i).

2.6.1 Rigid Pipeline

Rigid pipes are usually made of carbon steel and manganese (Mn). They are the most popular and most used pipelines in the subsea industry due to their low cost, good mechanical properties and ease of fabrication. However, there are some challenges with the use of rigid pipelines such as large weight and corrosion problems. Advantages and disadvantages of rigid pipelines are summarized in Table 2.2 (Subramanian, 2013).

Table 2.2: Advantages and disadvantages of a rigid pipeline.

Advantages	Disadvantages
Cheap to produce	Large weight
Good mechanical properties	Corrosion problems
Can be pigged	Time consuming and expensive installation process

2.6.2 Flexible Pipeline

A flexible pipeline is a pipe that is much more flexible than a rigid pipeline. Flexible pipes are divided into two main categories; static and dynamic. Both of them offer excellent mechanical strength, long life, corrosion resistance, damage resistance and minimal maintenace actions. Dynamic pipes also offer excellent fatigue resistance and bending. Typical applications for dynamic pipes are; risers for offshore loading systems and riser connections between floating production facilities and subsea equipment. Static flexibles are typically applied on subsea flowline end connections, field developments with uneven seabed and situations involving movements and damage to flowlines (American Petroleum Institute, 2002). A flexible pipeline consists of several functional layers (Bai and Bai, 2010j):

- A stainless steel internal casing
  - Designed to resist external pressure
- A thermoplastic sheath
  - That creates a fluid seal
- A helical wound steel wire
  - Designed to resist internal pressure
- An external polymer sheath
  - Provides protection from the environment
- Optional external stainless steel carcass

– Provides additional protection

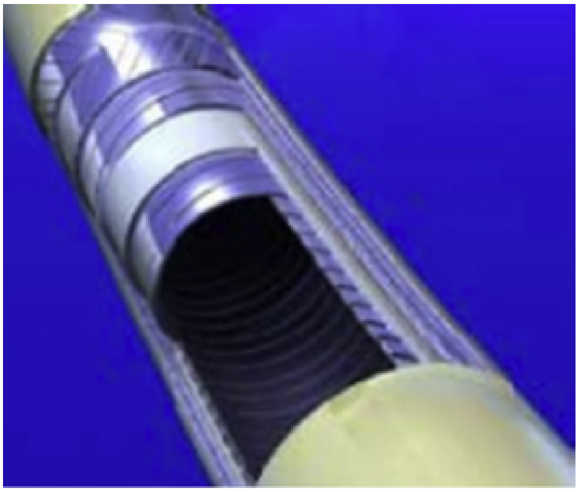

Figure 2.24: Flexible pipe (Bai and Bai, 2010j).

Advantages and disadvantages of a flexible pipe are summarized in Table 2.3.

Table 2.3: Advantages and disadvantages of a flexible pipeline.

Advantages	Disadvantages
Flexible	Expensive compared to a rigid pipeline
High temperature resistance	Smaller diameter for a high internal pressure
Suitable for both dynamic and static service	-
High collapse resistance	-
High fatigue life	-

2.6.3 Multibore Pipeline

A multibore pipeline is several pipelines that is combined and bundled together into one single pipeline, reducing the total number of pipelines. Hence, the field layout and installation will be simplified. In order to provide structural integrity and protection, a polymer sheath should be extruded outside the pipe bundle (American Petroleum Institute, 2002).

2.7 Subsea Connection Systems

A subsea field development require different equipment to be tied-in through pipelines in a safe and reliable operation. Generally, two types of connection systems are applied today, which is horizontal and vertical. Regardless of connection system, the main function of the connection method is to create a pressure-tight seal that avoids contact from the subsea environment (Bai and Bai, 2010j).

2.7.1 Vertical Connection Systems

Subsea vertical connection systems are systems where the connector is installed vertically onto a hub. Since they are installed from a vertical position, gravitational forces will help to bring the connector onto the hub. Nevertheless, external tooling is also required. The main functions of the external tooling are pulling and alignment of the connector and hub (Bai and Bai, 2010j). Correct alignment is important in order to make the connection leak free. Figure 2.25 illustrates a vertical connection operation which is carried out by a Connector Actuation Tool (CAT).

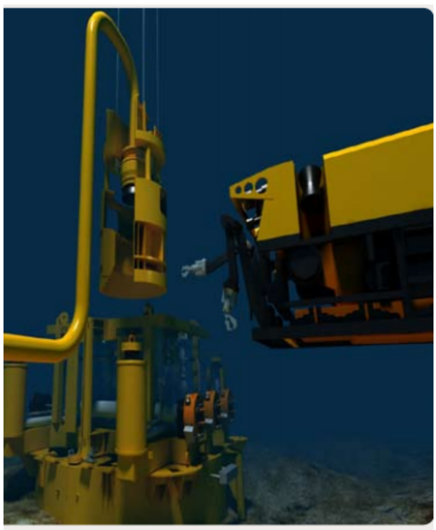

Figure 2.25: Vertical connection system (FMC Technologies, 2017c).

Compared to a horizontal connection system, the vertical is relatively time efficient. However, there are some drawbacks. Vertical connection systems are not suitable for pipelines with large diameters due to the height required to obtain the necessary pipeline bend. In addition, there are challenges regarding fishing protection and the dependency of weather due to the use of guidelines. Table 2.4 presents advantages and disadvantages of a vertical connection system.

Table 2.4: Advantages and disadvantages of vertical connection systems.

Advantages	Disadvantages
Simpler connection procedure compared to horizontal connection systems due to more independency of external tooling.	Challenges with fishing/trawl protection.
Gravity helps to bring the connector to the hub.	Not suitable for pipelines with large diameters.
More time efficient connection operation compared to horizontal connection systems.	Connection operations are dependent on weather.

2.7.2 Horizontal Connection Systems

Horizontal connection systems are systems where the connectors are installed horizontally onto a subsea hub. Depending on on the pipeline selected, two types of horizontal connection tools are normally applied. Jacking connection tools are developed for rigid pipelines, while pull-in tools are developed for flexible pipelines (Bai and Bai, 2010j).

During a connection operation, the pipeline should first be lowered onto a guiding structure that roughly aligns the pipe. Final alignment is performed using guide pins that are mounted on a tie-in porch. Stroking the hubs together with the help of a Remotely Operated Vehicle (ROV) or a CAT is then performed. Figure 2.26 illustrates the Stab and Connect Connection System (STABCON) provided by FMC Technologies. Using this system, the connection operations will approximately take 1,5 hours (Thoresen, 2016).

Figure 2.26: STABCON horizontal connection system (Bai and Bai, 2010j).

Compared to a vertical connection system, a horizontal is more complex and relies more on external tooling. This is one of the reasons why the connection time is longer for a horizontal connection operation compared to a vertical. However, an advantage is that the operation is independent of vessel motion meaning no weather downtime. Table 2.5 highlights advantages and disadvantages for a horizontal connection system.

Table 2.5: Advantages and disadvantages for horizontal connection systems.

Advantages	Disadvantages
Few challenges with fishing/trawl protection.	Need more external tooling for the connection operation compared to a vertical connection system.
Easier to connect large pipes compared to a vertical connection system.	Rigid pipes require that the end of the pipeline is supported on the seabed.
Connection operation is independent of weather.	More time consuming connection operation compared to a vertical connection system.

2.7.3 Connector Types

Several types of connectors are applied subsea. The common feature for all connector types, is that they provide tightness by the use of metal to metal seals. By this feature, plastic deformation of the softest material into the micro-geometry of the hardest metal occur. This means that every time a new connection is conducted, a new metal gasket must be used in order to obtain the maximum quality of the seal (Krishna and Lefrancois, 2016). The most common connector types for subsea applications are described below.

2.7.3.1 Clamp Connector

Clamp connectors are mainly used in horizontal connection systems (FMC Technologies, 2017a). Normally, these types of connectors are relatively small and easy to handle. A clamp connector can be seen in Figure 2.27. The working principle is that a clamp forces two mating hubs together as the clamp is tightened. A metal gasket is located between the hubs that creates a seal which should be pressure tested after the connection is made, to check if the connection is tight. The final alignment is conducted by the use of guide pins that are mounted on backing plates or tie in porches (Damsleth et al., 2012). Clamp connectors are generally popular for subsea applications due to their relatively small size, small numbers of bolts to handle and short installation time (Bai and Bai, 2010j).

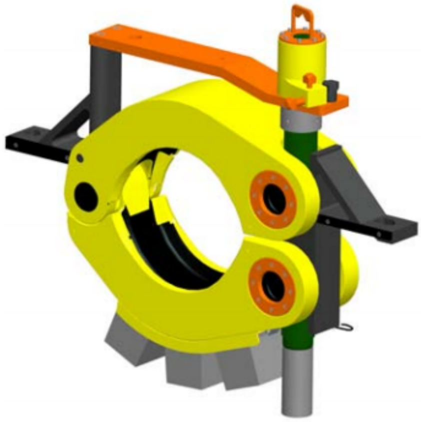

Figure 2.27: Clamp connector (FMC Technologies, 2017a).

2.7.3.2 Collet Connector

Collet connectors are the most common type of connectors used for jumper connections, seen in Figure 2.28. They may be applied in both horizontal and vertical connection systems. Typically, a collet connector consists of a body and a hub. A seal is created between the body and the hub by a compressed metal gasket. "Fingers" or collets are arranged on the hub in a circular pattern. A connection is made when these collets are gripping onto the pipe, which is actuated by an ROV that provides either mechanical or hydraulic power to the operation. After the connection has been executed, the metal seal should be pressure tested in order to check if the connection is tight (Bai and Bai, 2010j).

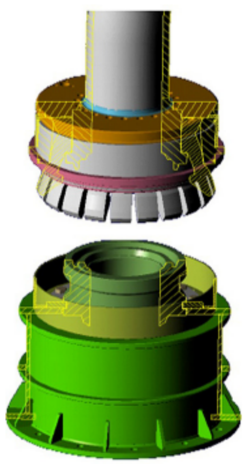

Figure 2.28: Collet connector (Bai and Bai, 2010j).

2.7.3.3 Bolted Flange Connector

Bolted flange connectors are connectors that consists of two flanges with a metal gasket between the flanges to create a seal. The flanges make contact to each other when they are fastened with bolts. It is important that the flanges are aligned properly to obtain connection tightness. Swivels can be in place to account for rotational misalignment (Bai and Bai, 2010j).

The bolted flange connector is preferred for pipeline connections installed in shallow water by divers, due to its cheap and reliable construction. In deeper waters, this is more challenging due to the number of bolts that must be fastened. Specialized ROV-tools can operate the bolted flange connector, but the operation is more time consuming compared to a clamp connector due to the increased number of bolts that must be fastened (Frazer et al., 2007).

Figure 2.29: Bolted flange connector (Frazer et al., 2007).

2.7.3.4 Multibore Connector

A multibore connector is a connector that connects multiple lines. A multibore connector allows connection of chemicals lines, hydraulic lines, production lines, water injection lines, fibre optics and electrical lines that are in the same pipe bundle. A multibore collet connector can be seen in Figure 2.30. Since multiple lines are connected simultaneously, the installation time is decreased compared to if monobore connections were applied.

As for monobore connectors, each connection point must be metal sealed such that no leakages can occur. A seal plate is normally applied on multibore connections to make installation and removal of metal seals more time efficient. Due to strict requirements of no leakage, a new seal plate must be installed on the multibore connection every time reconnections are conducted (Thoresen, 2016).

A multibore connector can be concentric and nonconcentric. Nonconcentric multibore connectors require rotational alignment of the outboard and inboard hubs, while concentric multibore connectors do not require rotational alignment (American Petroleum Institute, 2015). Both clamp connection systems and collet connector systems are normal to apply for subsea multibore connections.

Figure 2.30: Multibore collet connector (FMC Technologies, 2017b).

2.8 Redundancy of Chemical Injection Systems

In order to ensure increased reliability and availability of the chemical injection system, redundancy should be implemented into the system. By putting equipment in parallel into a system, redundancy is achieved by building over-capacity in the system (Jardine, 1986). Generally, two ways of redundancy are present today. They are active and passive redundancy. Active redundancy means to replace an important component in parallel with two or more components. Passive redundancy means to have a reserve component in standby that first is activated when the ordinary component fails. Figure 2.31 shows the principle of a passive dual redundant system. When component 1 fails, component 2 will be activated immediately. The system will fail if component 2 fails (Rausand and Høyland, 2004).

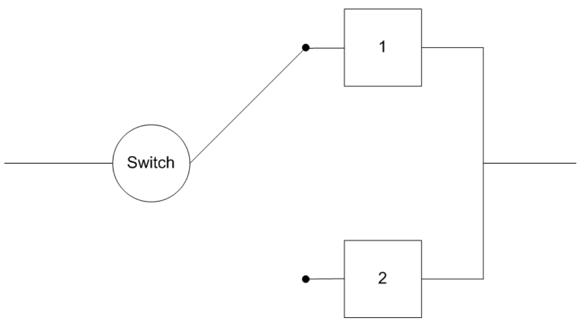

Figure 2.31: A passive dual redundant system.

Production chemicals are diverse in nature and formulation. Hundreds of these fluids have been applied in subsea production of oil and gas. Except the manufacturers, little is known about the composition and stability of them. It is stated that blockages in umbilical lines (also chemical injection lines) occurs more frequently than envisaged, but due to secrecy in the industry this is rarely made public (Stables, 2010). This illsutrates why it is important to design a chemical injection system in a way so it can handle different and challenging scenarios. A chemical injection system must be flexible and redundant. Hence, if failure of critical components occurs, a solution for this should be in place to avoid a system breakdown before corrective maintenance actions can take place. A system breakdown is extremely expensive. (Willmon and Edwards, 2006).

In a chemical injection system, many components are critical. In order to have high availability and reliability of the system, redundancy is required. Common cause failures should be avoided. Critical components regarding the chemical injection systems on a SCS&I-station are:

- Chemical storage tanks
- Connectors
- Sensors
- Chemical injection pumps
- Chemical injection lines
- Subsea Control Module
- Subsea Electronics Module
- Valves

The overall design of the whole subsea production system is also important. As the complexity of the subsea production system increases, more connections and equipment are present.

2.9 Research Method

In this subsection the research method used in this thesis will be presented. Here a concept selection method named Concept Scoring is utilized. Concept selection methods are used to help a design team to compare different concepts, and select one or a few of the optimum concepts for further investigation, testing and/or development (López-Mesa and Bylund, 2011).

2.9.1 Concept Scoring

In conceptual development, one often have a large set of concepts before the project matures. Concept Scoring is a method used to narrow down many concepts into a manageable set of options, and eventually concept selection. The first step of Concept Scoring is to develop a set of parameters that will suit into the so-called Concept Scoring Matrix. The Concept Scoring Matrix is used to determine which concept to develop and which to discard (based on a weighted total score). A base option is then chosen, against which other options selected. Each concept is given a score based on the parameters developed in the first step to give them a relative score. Each parameter will be rated from 1 to 6, where 1 is not acceptable and 6 is excellent characteristics. An importance degree will also be given to each parameter, rated from 1-4. A weighted total score is then obtained by multiplying the importance degree with the selected parameter. The concept with the highest weighted total score is then selected for further investigation.

2.9.2 Why Concept Scoring?

Concept scoring is chosen as research method due to its applicability regarding concept selection. It is an efficient method that rank concepts against each other, highlighting their strengths and weaknesses. Some of the main objectives of this thesis are to find preferred tank design and alternative system architecture. Concept scoring becomes a valuable tool in choosing the best suited tank design and system architecture in this thesis.

Chapter 3

Results

In this chapter, the results of the research objectives defined in Section 1.1 are presented. A complete overview of of calculations used in Section 3.1, are found in Appendix A.

3.1 Calculation of Total Storage Tank Volume

Total storage tank capacity is calculated based on the different injection rates for each chemical provided by Beaudonnet et al., (2012). There are two categories of chemicals considered; production chemicals and hydrate inhibitors (Peyrony and Beaudonnet, 2014). Production chemicals are; corrosion, scale and asphaltene inhibitor, demulsifier and biocide while hydrate inhibitors are methanol and LDHI.

There are two cases assessed in this section; the difference in required storage volume when methanol is stored subsea and topside. Methanol is singled-out due to its vast consumption. With rates ranging from 5 000 to 25 000 l/hr the required storage volume becomes high depending on required methanol injection to the subsea field.

According to Beaudonnet et al., (2012) production chemicals are injected continuously with rates of 6 to 20 l/hr, except biocide which is injected at batch mode at 5 hrs/week at a rate of 180 l/hr. In Table 3.1 a minimum, base and maximum case is presented. The base case is selected for further calculations. The same methodology applies for hydrate inhibitors; a minimum, base and maximum case is presented in Table 3.2. The injection rate of hydrate inhibitors are substantially higher than for production chemicals, and they are injected periodically. Methanol is injected at rates ranging from 5 000 to 25 000 l/hr. According to Clark et al., (2005), LDHI is typically injected at levels of 0,25 to 5 vol% of the produced water while thermodynamic hydrate inhibitors, such as methanol, is injected at rates of 10-40 vol%. The injection rates of LDHI is therefore much lower than for methanol. It is assumed that the injection volume of methanol is 20 times larger than for LDHI, resulting in an injection range of 250 to 1250 l/hr. The maximum case is selected to ensure hydrate prevention. The hydrate inhibitors are only injected during shutdown and/or start-up sequences. In the calculations it has been assumed that methanol and LDHI are injected in duration of 6 hours, three times every 6 months. The injection duration of 6 hours comprises a 3 hour shutdown and 3 hour start-up operation. It is also assumed that the chemical injection rates given are for the combination of the four wells. The length of these operations are however very uncertain.

Table 3.1: Required storage capacity of production chemicals is presented in a minimum, base and maximum case.

Production chemicals -	**Min case** [m^3]	**Base case** [m^3]	**Max case** [m^3]
Corrosion inhibitor	26.3	56.9	87.6
Scale inhibitor	26.3	56.9	87.6
Asphaltene inhibitor	26.3	56.9	87.6
Demulsifier	26.3	56.9	87.6
Biocide	23.4	23.4	23.4
Sum:	128.5	251.1	373.8

Table 3.2: Required storage capacity of hydrate inhibitors is presented in a minimum, base and maximum case.

Hydrate inhibitors -	**Min case** [m^3]	**Base case** [m^3]	**Max case** [m^3]
Methanol (3×6 hrs injection)	90.0	270.0	450.0
LDHI (3×6 hrs injection)	4.5	13.5	22.5
Sum:	94.5	283.5	472.5

3.1.1 Total Storage Tank Volume When Methanol is Stored Subsea

In this section, the total storage tank volume of the SCS&I-station when methanol is stored subsea is considered. The production chemicals as well as the hydrate inhibitors are stored subsea at the SCS&I-station. The base case of Table 3.1 is selected and the maximum case of Table 3.2 is selected. Total storage tank capacity is given in Table 3.3 with required number of modules.

One module has a total storage tank capacity of 30 m^3. This means that each tank can store 7,5 m^3 of chemicals. For design purposes, it has been assumed that no chemicals shall share a module. According to the calculated storage tank capacity, the theoretical number of required modules are actually 24,2. However, 25 tank modules are selected to avoid chemical sharing. The number of required modules for each chemical of each case can be seen in Appendix A together with the calculations. An interesting observation is that methanol occupies 60% of the required number of modules.

Table 3.3: Total storage tank volume and number of modules required for the SCS&I-station when methanol is stored subsea.

Chemicals -	**Total storage tank capacity** [m^3]	**Total tank modules required** -
Production chemicals	251.1	9
Hydrate inhibitors	472.5	16
Sum:	723.6	25

3.1.2 Total Storage Tank Volume When Methanol is Stored on FPSO

Since methanol consumption is substantially higher than the other chemicals, an assessment of potential methanol storage on the FPSO is done. The production chemicals and LDHI is stored subsea at the SCS&I-station along with two redundancy modules with methanol. Two redundancy modules with methanol are assumed to be enough satisfying one shutdown and start-up operation. Having two modules, an injection rate of 10 000 l/hr is available. Table 3.4 presents the total storage tank volume with required number of modules. One module has the same storage capacity as explained in Subsection 3.1.1. Chemical sharing is not applicable in this case either.

Table 3.4: Total storage tank volume and number of modules required for the SCS&I-station when methanol is stored topside.

Chemicals -	**Total storage tank capacity** [m^3]	**Total tank modules required** -
Production chemicals	251.1	9
LDHI	22.5	1
Methanol (redundancy)	60	2
Sum:	333.6	12

The difference in required number of modules from subsea storage of methanol to topside storage is 13. This shows great potential in SCS&I-station size reduction by topside storage of methanol. A reduction of weight and tank module change-out time is also present, as more than half of the tank storage volume is removed (with shutdown/start-up sequences of 3×6 hours per 6 months). A sensitivity analysis of methanol storage follows in the next subsection.

3.1.3 Sensitivity Analysis of Methanol Storage

Shutdown and start-up sequences has great impact on hydrate inhibitor consumption. Due to large injection rates, uncertainties regarding injection time and the potential of unforeseen incidents, a sensitivity analysis is provided. Figure 3.1 shows how storage of hydrate inhibitors subsea increases dramatically with increased shutdown/start-up time. It is methanol that drives this trend due to the 25 000 l/hr requirement, which is illustrated by the blue line in Figure 3.1. A small change in the shutdown/start-up length has significant impact on the total storage volume of the SCS&I-station. If methanol is stored topside on the FPSO, the increase in volume storage is almost negligible. A discussion in Section 4.1 is provided to highlight the strengths and weaknesses of storing methanol topside.

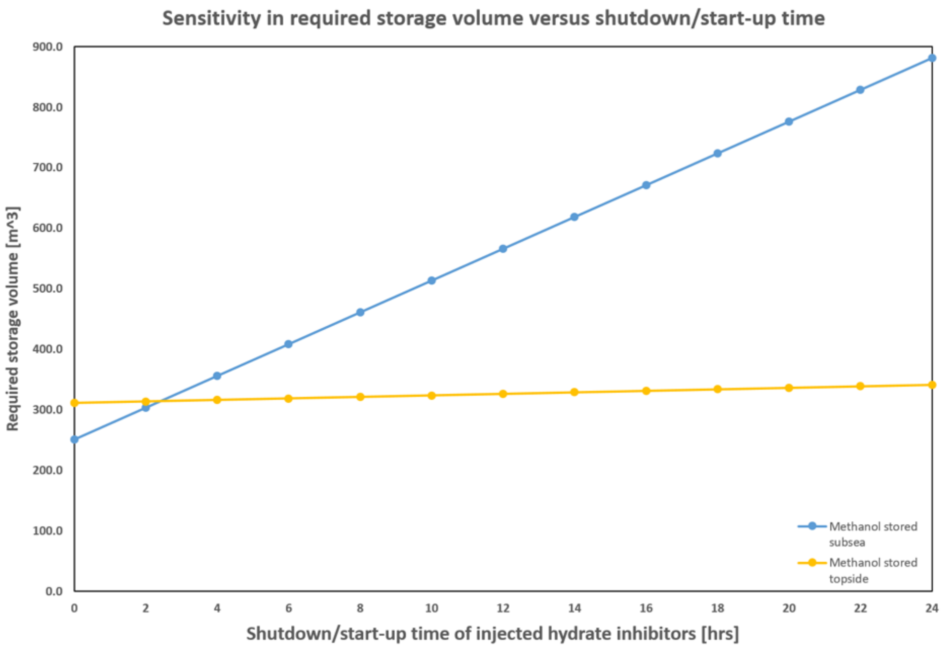

Figure 3.1: Sensitivity in total storage volume required of subsea versus topside storage of methanol. As shutdown/start-up time increases, the storage volume required increases dramatically for a subsea solution opposed to a topside solution.

The number of modules required follows the same trend as volume storage, which Figure 3.2 indicates. Figure 3.2 shows the difference in number of modules needed with increased shutdown/start-up time when methanol is stored subsea or topside. If a subsea storage solution is preferred, the refill time will rise accordingly. Vessel rent and crew to enable tank refill is a costly operation. It is of importance to try to lower the costs associated with refill of chemical supply. An economical assessment regarding this is provided in Section 3.6.

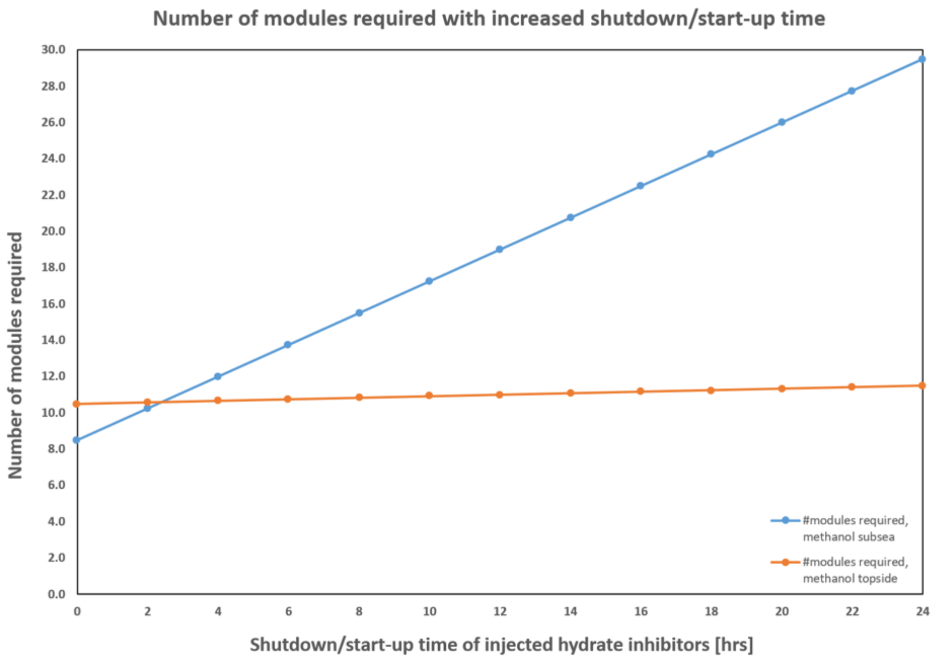

Figure 3.2: Sensitivity in required number of modules as total volume storage increases with increased shutdown/start-up time. The number of modules needed increases vastly for a subsea storage solution to a topside solution.

3.1.4 Methanol Influence on SCS&I-station Size

To illustrate how huge impact methanol storage has on SCS&I-station overall size, an illustration of a station with and without methanol is provided in Figure 3.3. To give an idea of how large the structures will become, they are located on a football pitch that measures 100×70 metres. The station with methanol storage consists of 25 modules and has dimensions of 40×27 metres, and is located on the left hand side of the illustration. If methanol is placed topside the number of modules decreases to 12, and the station size reduces to 29×20 metres, as illustrated on the right hand side. If methanol is to be stored topside a substantial size, weight and installation time decrease is evident. Note that Figure 3.3 illustrates SCS&I-stations for a centralized system architecture.

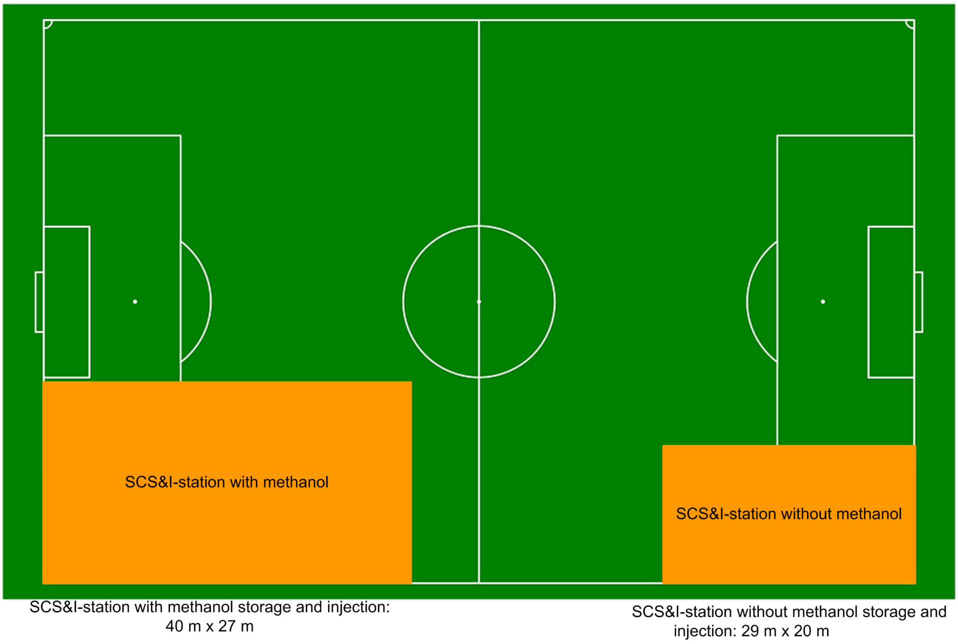

Figure 3.3: Difference in size for SCS&I-station with and without methanol storage and injection. The stations are located at a football pitch.

The station sizes presented above are calculated with the basis of following assumptions:

- Each tank module consists of four storage tanks, pipes and a distribution system containing chemical injection pumps, filters, etc.

- Each storage tank is 5 m high and is assumed to have quadratic sides of 1,25 m to satisfy the 30 m^3 module storage requirement.

- The distribution system in a tank module is 2 m wide and 4 m long.

Using the assumptions above, a module is sketched in Figure 3.4. The storage tanks have to be independently retrievable and it is therefore incorporated some distance between each tank to ensure safe retrieval.

Figure 3.5 shows a simple sketch of a SCS&I-station when methanol is stored subsea and it counts 25 tank modules. The modules are placed in close proximity to each other, only separated by the frameworks. The chemicals are routed to the control and distribution unit as illustrated.

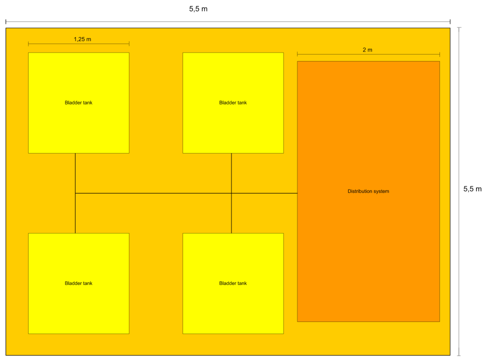

Figure 3.4: Simple tank module.

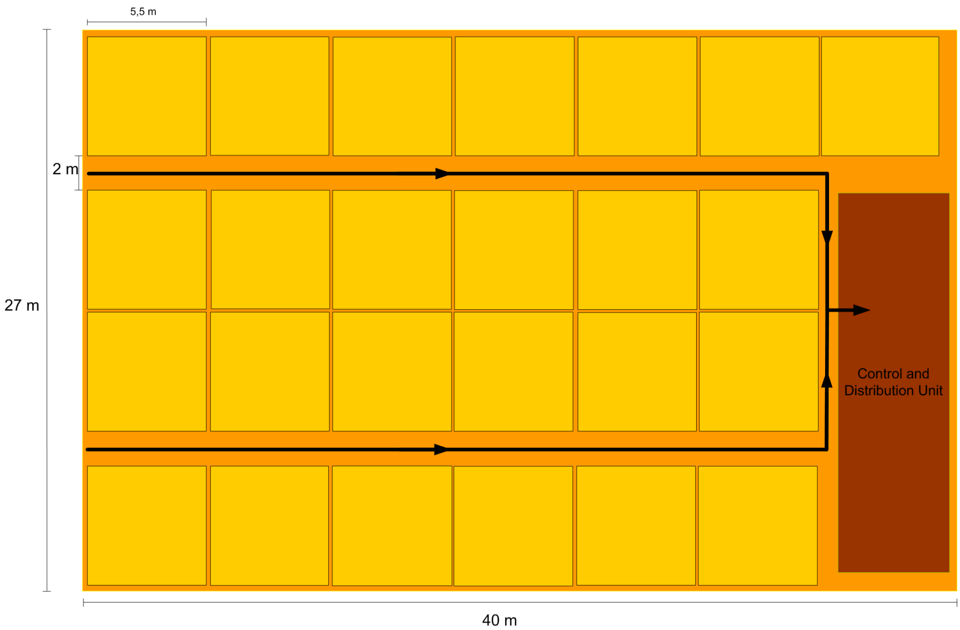

Figure 3.5: SCS&I-station with methanol.

3.2 Subsea Chemical Storage Tank Selection

There are five tank proposals as presented in Subsection 2.4.1; piston tank, bladder tank, membrane tank, rolling tank, and pillow tank. One tank proposal should be selected for further evaluation. In order to do so, Concept Scoring is applied. In this section, an explanation of the scoring of each solution will be provided in Table 3.5, 3.6 and 3.7. In addition, the importance degree will be provided in Table 3.8 with elaboration of the respective degrees. Each tank is rated in Table

3.9 on the same parameters with those provided by Total and Doris (Peyrony and Beaudonnet, 2014). The reason for only considering the same parameters is to challenge Total and Doris with their chosen pressure-balanced tank concept. This will strengthen the pros and cons of each pressure-balanced tank proposal. Table 3.10 provides the Concept Scoring Matrix containing each pressure balanced tank design.

Table 3.5: Description of parameters given the score 1-2 regarding storage tank selection.

No.	**Parameter**	**Description of parameters given the score 1-2:**
1	Weight	The weight of the tank exceeds the design limitation.
2	Chemical compatibility	The tank has a low degree of chemical compatibility.
3	Monitoring	It is difficult or impossible to monitor the tank conditions and fluid level.
4	Filling and maintenance	The tank degree of maintainability and filling is low. When maintenance and filling is needed, high costs and long downtime will occur.
5	Manufacturability	The tank manufacturability is time consuming and contains many parts with high procurement cost.

Table 3.6: Description of parameters given the score 3-4 regarding storage tank selection.

No.	**Parameter**	**Description of parameters given the score 3-4:**
1	Weight	The weight of the tank is acceptable, but is still a system liability.
2	Chemical compatibility	The tank has a descent degree of chemical compatibility.
3	Monitoring	The tank and fluid level can be monitored in an acceptable manner with trustworthy data.
4	Filling and maintenance	The tank degree of maintainability and filling is acceptable. When maintenance and filling is needed, no high costs or long downtime will occur.
5	Manufacturability	The tank manufacturability is not too complex and time consuming.

Table 3.7: Description of parameters given the score 5-6 regarding storage tank selection.

No.	Parameter	Description of parameters given the score 5-6:
1	Weight	The weight of the tank is good. Well within design limitations.
2	Chemical compatibility	The tank has great to excellent chemical compatibility.
3	Monitoring	The tank and fluid level can easily be monitored and gives real-time data of the tank conditions.
4	Filling and maintenance	The tank degree of maintainability and filling is good. When maintenance and filling is needed, no high costs or long downtime will occur.
5	Manufacturability	The tank manufacturability is very satisfying, with low cost and efficient assembly.

Table 3.8: Degree of importance with description.

Degree of importance	Description
1	Parameters without the need for weighting.
2	The parameter is weighted two times the previous one. This applies to parameters that have a greater importance to the overall system.
3	The parameter is weighted triple. This applies to parameters that are critical for the overall system and has great importance within the requirements.
4	The parameter is weighted quadruple.This applies to parameters that are extremely critical for the overall system and has great importance within the requirements.

Table 3.9: Tank scores for different selection criteria.

Selection Criteria	Piston tank	Bladder tank	Membrane tank	Rolling tank	Pillow tank
Weight	3	5	4	5	5
Chemical Compatability	3	6	4	4	5
Monitoring	5	3	3	5	2
Filling and maintenance	4	5	2	3	2
Manufacturability	4	4	3	1	2

Table 3.10: Concept Scoring Matrix for pressure-balanced tank selection.

Selection Criteria	Importance	Piston tank	Bladder tank	Membrane tank	Rolling tank	Pillow tank
Weight	3	9	15	12	15	15
Chemical Compatability	3	9	18	12	12	15
Monitoring	1	5	3	3	5	2
Filling and maintenance	2	8	10	4	6	4
Manufacturability	1	4	3	3	1	2
Sum		**35**	**49**	**34**	**39**	**38**

The best suited solution from the Concept Scoring selection from each pressure-balanced tank concept, is the bladder tank. This pressure-balanced bladder tank is selected for further evaluation and investigation in relation to the overall SCS&I system. Discussion regarding parameters given high importance, will be discussed in Section 4.2. An interesting observation is the deviation from Total and Doris' proposed piston tank solution. The piston tank solution had the second lowest overall score. The tank is relatively heavy due to a robust and heavy construction design. Also, chemical compatibility can be an issue due to the elastomer seals. Scoring relatively low in these key importance selection criteria led to a low total score, eventually not choosing this design.

3.3 Architecture

Two different well configurations have been studied in this thesis; a tight cluster with flowline distances of 50 m from wellheads to manifold and a wide cluster with flowline distances of 1000 m from wellheads to manifold. A centralized architecture and a decentralized architecture have been studied for each of the two well configurations. A centralized system architecture is when one SCS&I-station supplies the X-mas trees and manifold with chemicals. The SCS&I-station is localized some distance from the well configuration. A decentralized system architecture is when a SCS&I-station is localized close to each X-mas tree and manifold. The best suited solutions will be chosen by the Concept Scoring Matrix in Section 3.3.5.

3.3.1 Tight Cluster - Centralized Architecture

In this architecture solution, one large SCS&I-station provides the four wells and manifold with chemicals. Figure 3.6 shows how a centralized architecture solution would look in a tight cluster well configuration. Some general advantages and disadvantages of the system are listed in Table 3.11.

Table 3.11: Advantages and disadvantages with a centralized architecture in a tight cluster.

Advantages	Disadvantages
Easier for maintenance vessels to retrieve equipment when needed (shorter time) compared to a decentralized architecture.	The main structure is very large and heavy meaning there will be challenges with transportation, immersion and installation.
Less time consuming to perform inspections with an ROV compared to a decentralized architecture.	-
The power cable can be connected at one point on the SCS&I-station. From there, further distribution to sub-systems can be performed.	-

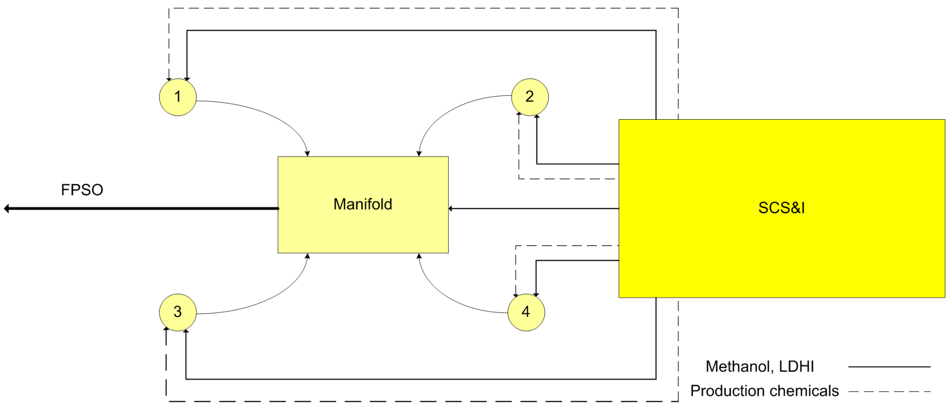

Figure 3.6: Centralized architecture in a tight cluster well configuration. The distances shown is for illustrative purposes only, and does not reflect actual flowline distances.

The greatest challenge with a centralized architecture solution in a tight cluster well configuration is the transportation, immersion and installation of the main structure due to its size and weight. However, transportation, immersion and installation of very large subsea structures have been executed before (Åsgard Subsea gas compression unit).

3.3.2 Tight Cluster - Decentralized Architecture

Figure 3.7 shows how an imagined decentralized architecture solution would look like in a tight cluster well configuration. Each well and manifold has a designated SCS&I-station that provide them with chemicals. Note that the SCS&I-station that supplies the manifold only contains hydrate inhibitors. Some general advantages and disadvantages of the system are presented in Table 3.12.

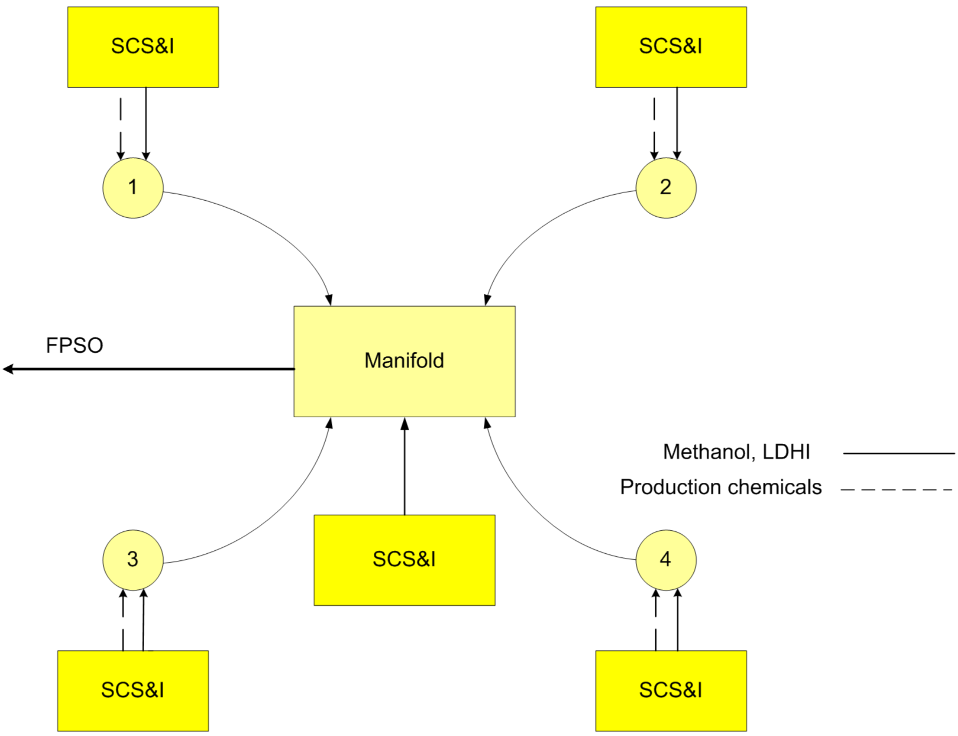

Figure 3.7: Decentralized architecture in a tight cluster well configuration. The distances shown is for illustrative purposes only, and does not reflect actual flowline distances.

Table 3.12: Advantages and disadvantages with a decentralized architecture solution in a tight cluster.

Advantages	Disadvantages
Short distance from SCS&I-stations to wells and manifold, meaning short response time on hydrate inhibitors.	The power cable must be split up subsea.
Chemical injection pumps are placed close to wells and manifold, making it easier to have a higher degree of precision when dosing chemicals.	One SCS&I-station per well and manifold will be an expensive solution in a tight cluster.

3.3.3 Wide Cluster - Centralized Architecture

In this architecture solution, one large SCS&I-station provides the four wells and the manifold with chemicals. Figure 3.8 shows how a centralized architecture solution would look like for a wide clustered well configuration. Some general advantages and disadvantages of the system are given in Table 3.8.

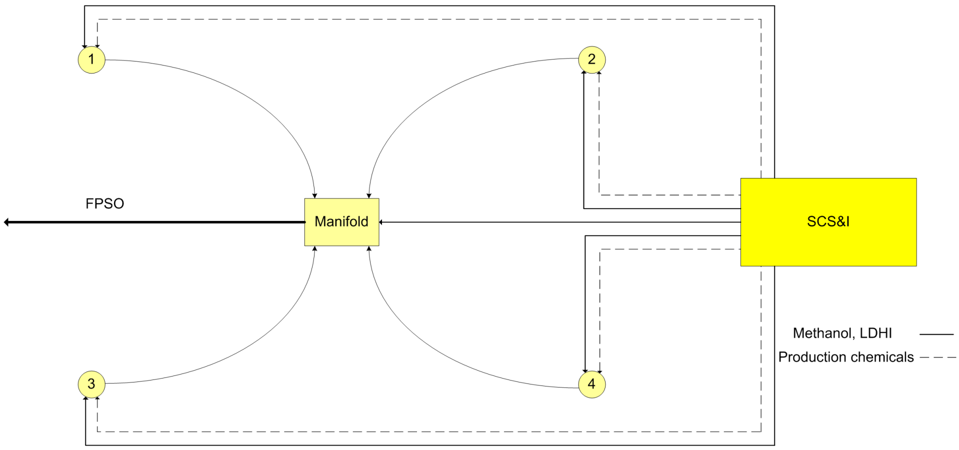

Figure 3.8: Centralized architecture in a wide cluster well configuration. The distances shown is for illustrative purposes only, and does not reflect actual flowline distances.

In a centralized architecture solution, all the equipment is at one place. Refill operations and inspections will be less time consuming compared to a decentralized system architecture.

Table 3.13: Advantages and disadvantages with a centralized architecture solution in a wide cluster.

Advantages	Disadvantages
Less time consuming for MPSV to do a refill operation since all equipment is at one place.	Challenging to keep high accuracy of the dosage of production chemicals due to the length of the chemical injection flowlines.
The power cable can be connected at one point on the SCS&I-station where power distribution to main equipment and subsystems can be performed.	A friction loss in the chemical injection lines is present.
Less time consuming to perform inspection since all equipment is at one place.	Higher chemical injection flowline costs compared to a decentralized architecture.

3.3.4 Wide Cluster - Decentralized Architecture

In this architecture solution, each well has a SCS&I-station that provide the wells with the different chemicals. The manifold must be supplied with hydrate inhibitors during shutdown and start-up sequences. Hence, a SCS&I-station is located together with the manifold. Figure 3.9 shows how a decentralized system architecture would look like in a wide cluster well configuration. Some general advantages and disadvantages of the system are listed in Table 3.9.

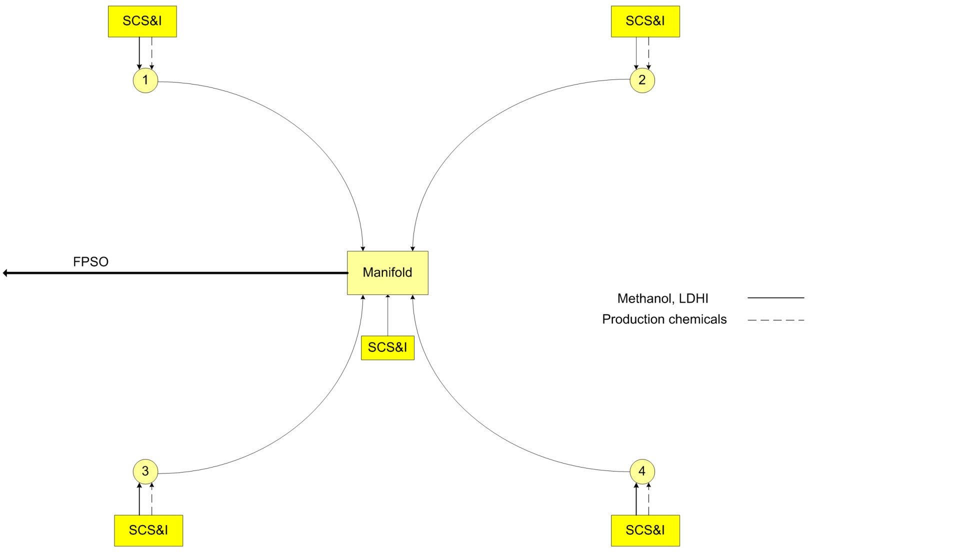

Figure 3.9: Decentralized architecture in a wide cluster well configuration. The distances shown is for illustrative purposes only, and does not reflect actual flowline distances.

Table 3.14: Advantages and disadvantages with a decentralized architecture solution in a wide cluster.

Advantages	Disadvantages
Response time of hydrate inhibitors is low.	More time consuming to perform inspections of the SCS&I-station compared to a centralized architecture.
Dosing of production chemicals will be performed accurately.	More time consuming to do a refill operation compared to a centralized architecture solution.

3.3.5 Selection of architecture

The method of Concept Scoring is utilized in order to find whether a centralized or decentralized system architecture for the two cluster cases is optimum. This is decided by the weighted scores of the Concept Scoring selection. In Table 3.15, 3.16 and 3.17 the explanation of the scores with selection criteria is presented. The selection criteria are developed on the basis of what seems to be the most important issues or features that the selected architecture system should be able to perform. The degree of importance is equivalent with the one presented in Table 3.8. Each solution is rated in Table 3.18, while Table 3.19 provides the Concept Scoring Matrix.

Table 3.15: Description of parameters given the score 1-2 regarding architecture selection.

No.	**Parameter**	**Description of parameters given the score 1-2**
1	Volume flow accuracy	The system cannot deliver the volume flow rate required. The deviation is not acceptable.
2	Simplicity	The system has a low degree of simplicity. Complex solution where many components must work simultaneously.
3	Cost	The system is expensive in assembly, operation, maintenance, tank change-out and inspection(time).
4	Reliability	The system is not effective enough to deliver the quantities of chemicals at the given pressure required.
5	Weight	The structure foundation is very large and heavy. Challenges arise with transportation, immersion and installation.
6	Response time	The system does not have a satisfactory response time when supplying chemicals to wellhead and/or manifold.
7	Redundancy	The system has no redundant system or of poor quality if something should fail.
8	Safety hazards	The structure poses a great danger to the security of the overall subsea development. If a fault occurs on the structure, it can in the worst case scenario stop operation.

Table 3.16: Description of parameters given the score 3-4 regarding architecture selection.

No.	Parameter	Description of parameters given the score 3-4
1	Volume flow accuracy	The system can deliver the volume flow rate of chemicals required. The deviation is acceptable.
2	Simplicity	The system is simple and is not based on highly advanced methods that require a high degree of monitoring.
3	Cost	The system will not require major expenses in assembly, operation, maintenance, tank change-out and inspection(time).
4	Reliability	The system is efficient enough to deliver quantities required of chemicals at the given pressures.
5	Weight	The weight of the structure foundation is manageable. Can encounter minor difficulties with transportation, immersion and installation.
6	Response time	The system has a satisfactory response time when supplying chemicals to wellhead and/or manifold.
7	Redundancy	If the system should fail, a redundant system is present and working in a limited time.
8	Safety hazards	The system is relatively safe without major risks of damage to the environment or overall subsea development.

Table 3.17: Description of parameters given the score 5-6 regarding architecture selection.

No.	Parameter	Description of parameters given the score 5-6
1	Volume flow accuracy	The system can deliver the volume flow rate required. The deviation is very small, almost negligible.
2	Simplicity	The system has a high degree of simplicity and does not include complicated methods. Monitoring is carried out easily.
3	Cost	The system cost is small in relation to typical subsea expenses regarding assembly, operation, maintenance, tank change-out and inspection(time).
4	Reliability	The system is very effective, enabling delivery of chemicals at given pressures at all times.
5	Weight	The weight of the structure foundation is relatively low causing no problems with transportation, immersion and installation.
6	Response time	The system has a quick response time when supplying chemicals to wellhead and/or manifold.
7	Redundancy	If the system should fail, a redundant system is present and working continuously.
8	Safety hazards	The system is safe without major risks of damage to the environment or overall subsea development.

Table 3.18: Architecture rating for different selection criteria.

Selection Criteria	Centralized 50 m	Decentralized 50 m	Centralized 1000 m	Decentralized 1000 m
Volume flow accuracy	5	6	2	6
Simplicity	4	2	4	2
Cost	5	3	4	3
Reliability	5	5	3	5
Weight	2	4	2	4
Response time	5	6	3	6
Redundancy	5	4	5	4
Safety hazards	5	4	5	5

Table 3.19: Concept Scoring Matrix for different system architectures.

Selection Criteria	Importance	Centralized 50 m	Decentralized 50 m	Centralized 1000 m	Decentralized 1000 m
Volume flow accuracy	3	15	18	6	18
Simplicity	1	4	2	4	2
Cost	4	20	12	16	12
Reliability	2	10	10	6	10
Weight	3	6	12	6	12
Response time	2	10	12	6	12
Redundancy	1	5	4	5	4
Safety hazards	2	10	8	10	10
Sum		**80**	**78**	**59**	**80**

For the tight cluster well configuration, the centralized architecture solution got the highest weighted score. Hence, this is the preferred architecture solution. The winning margin is however very small; 80 points for centralized solution to 78 points for decentralized solution. The scores given are debatable, and an assessment of the scores given for both centralized solution and decentralized solution for a tight cluster configuration will be presented in Section 4.3

For the wide cluster well configuration, the decentralized system architecture clearly got the highest weighted score; 80 points to 59 points. As the distance from wellhead to manifold increase, the strengths and weaknesses of each architecture solution amplifies. A discussion of how the increase in distance affects the features of each system architecture is presented in Section 4.3. A discussion of uncertainties is also included in Section 4.8.

3.4 Distribution Solutions

This section presents chemical distribution solutions for a tight and wide cluster well configuration with the preferred architectural system, which was found in the previous section. The aim is to illustrate how different well configurations in combination with either methanol storage topside or subsea alter the chemical distribution systems. Four cases are chosen; two cases for each well configuration where methanol is stored either topside or subsea. Case 1 and Case 2 presents the system architectures in a tight cluster, while Case 3 and 4 introduces the system in a wide cluster.

Common features for all cases are that the chemical injection lines from the SCS&I-station to their injection points are flexible. These flexible lines are gathered into a flexible multibore pipe bundle that is connected at the terminations (SCS&I-station, X-mas tree and manifold) with multibore connectors.

3.4.1 Tight Cluster Well Configuration

Case 1 presents the chemical distribution system when methanol is stored subsea, while Case 2 addresses the distribution system by topside methanol storage. A centralized system architecture is preferred for a tight cluster. A control umbilical from the FPSO connects to the SCS&I-station, which applies for both cases. This provides power supply and fibre optics to the chemical injection system which includes pumps, monitoring equipment, etc. Only the power lines regarding the chemical injection system are shown in the figures. Other subsea equipment have its own dedicated power supply system.

3.4.1.1 Case 1: Subsea Methanol Storage

A rough schematic overview of the chemical distribution system in a tight cluster well configuration when methanol is stored subsea can be seen in Figure 3.10. Table 3.20 highlight important advantages and disadvantages of the chemical injection system.

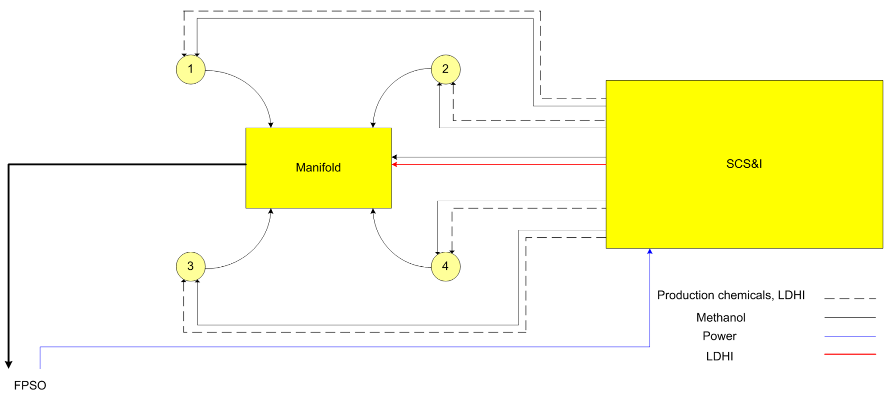

Figure 3.10: Chemical distribution system in a tight cluster well configuration. Methanol is stored and injected subsea.

Table 3.20: Advantages and disadvantages with subsea methanol storage in a tight cluster.

Advantages	Disadvantages
Short response time on methanol injection.	The SCS&I-station will be large and heavy.
Methanol is removed from the working site, meaning that HSE conditions of workers on the FPSO is improved.	Time consuming to perform a full refill operation since the number of methanol modules is large.
Methanol storage tanks are subsea, making more space for other equipment available on the FPSO.	-

3.4.1.2 Case 2: Topside Methanol Storage

Figure 3.11 schematically illustrates the distribution system when methanol is stored topside. Methanol is injected from the FPSO through a 6" rigid flowline. The line is connected to a distribution unit that splits the line and distributes methanol to the four wellheads and manifold through flexible lines at desired injection rates. A single chemical injection line from the SCS&I-station to the manifold is for LDHI injection, shown by the red line. For redundancy purposes, tank modules containing methanol are stored at the SCS&I-station in case a failure occurs in the 6" methanol injection line. The chemical injection lines for methanol redundancy modules are green. Table 3.21 summarizes important system advantages and disadvantages.

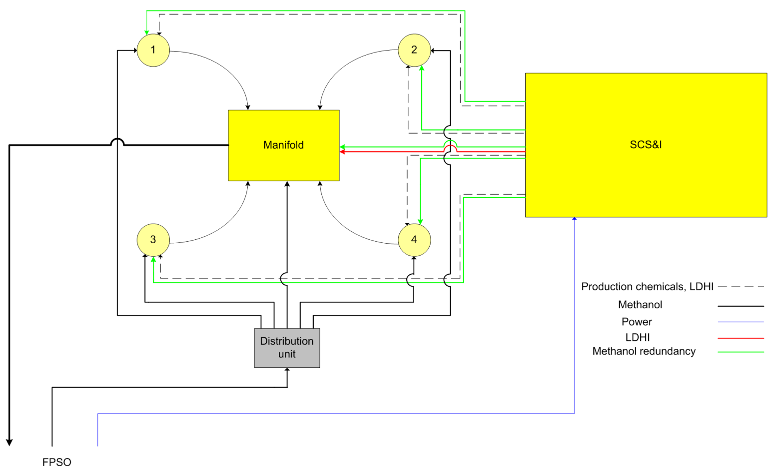

Figure 3.11: Chemical distribution system in a tight cluster well configuration. Methanol is stored and injected from the FPSO.

Table 3.21: Advantages and disadvantages with topside methanol storage in a tight cluster.

Advantages	Disadvantages
The size of the SCS&I-station will be heavily reduced compared to subsea storage of methanol.	By having a 6” methanol injection flowline, a distributuon unit is needed.
The duration of a refill operation is significantly reduced by storing methanol topside.	The response time of methanol is longer, meaning shutdown/start-up operations lasts longer.
-	HSE conditions for workers on the FPSO will worsen due to the potential hazards by methanol storage.

3.4.2 Wide Cluster Well Configuration

Case 3 assesses the chemical distribution system when methanol is stored subsea, while Case 4 illustrates the distribution system by topside methanol storage. A decentralized system architecture is preferred for a wide cluster well configuration.

A control umbilical from the FPSO connects to the SCS&I-station located close to the manifold. This provides power supply and fibre optics to the chemical injection system, and an electrical distribution unit is located on this station for further distribution of power and fibre optics to the other four stations. Only the power lines regarding the chemical injection system is shown in the figures. Other subsea equipment has its own dedicated power supply system.

3.4.2.1 Case 3: Subsea Methanol Storage

A schematical overview of the chemical distribution system when methanol is stored subsea is illustrated in Figure 3.12. Table 3.22 presents important advantages and disadvantages to the system design.

Table 3.22: Advantages and disadvantages with subsea methanol storage in a wide cluster.

Advantages	Disadvantages
Short response time on methanol injection.	The station sizes becomes larger due to the storage of methanol.
Methanol is removed topside, eliminating potential safety hazards due to methanol spillage.	Duration of refill operations increase due to longer distances between SCS&I-stations.
More space for other equipment is made available on the FPSO.	-

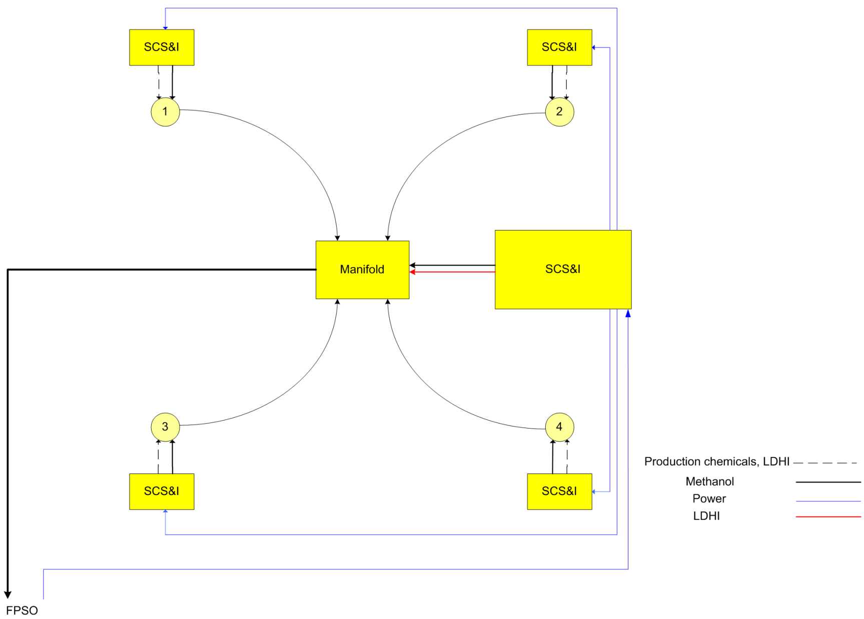

Figure 3.12: Chemical distribution system in a wide cluster well configuration. Methanol is stored and injected subsea.

3.4.2.2 Case 4: Topside Methanol Storage

Figure 3.13 schematically illustrates the chemical distribution system when methanol is stored topside. Methanol is injected from the FPSO through a 6" rigid flowline. This connects to a distribution unit that distributes methanol directly to the wellheads and manifold through flexible flowlines. Since LDHI must be injected into the manifold, LDHI must be stored at the distribution unit. For redundancy purposes, tank modules containing methanol are stored at each SCS&I-station and the distribution unit in case of methanol injection line failure. The chemical injection lines for methanol redundancy modules are green, except the injection line from the distribution unit. It is assumed that the methanol redundancy modules on the distribution unit, uses the same line as for normal injection. Table 3.23 highlights advantages and disadvantages.

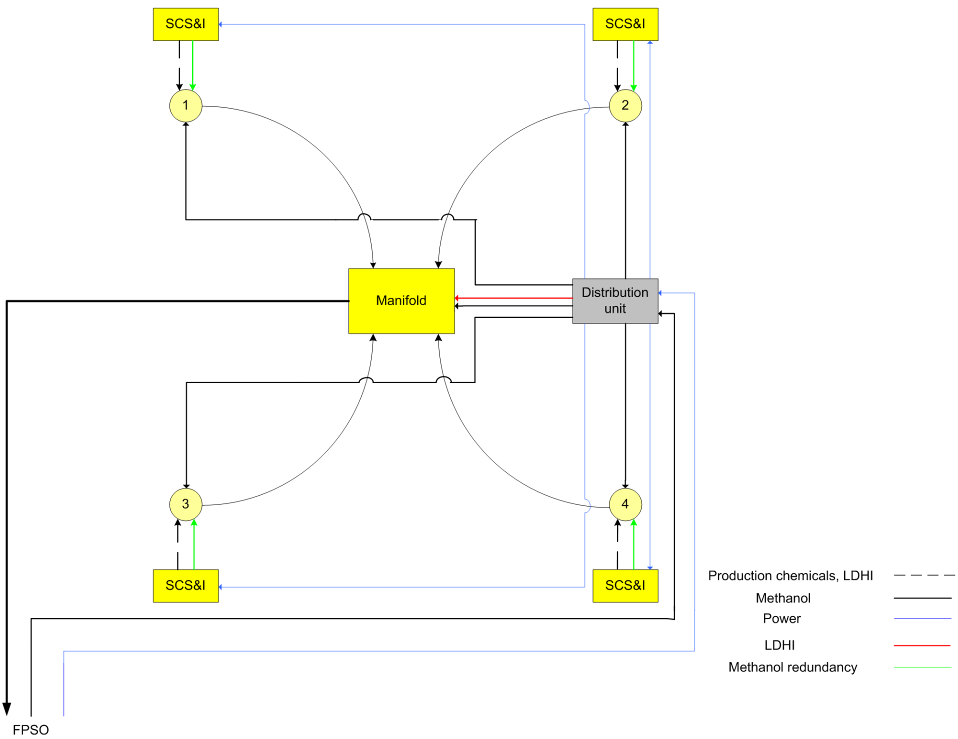

Figure 3.13: Chemical distribution system in a wide cluster well configuration. Methanol is stored and injected from the FPSO.

Table 3.23: Advantages and disadvantages with topside methanol storage in a wide cluster.

Advantages	Disadvantages
The duration of tank module change-out operations will decrease.	A distribution unit is required to distribute methanol to each well. This unit must also store LDHI and a redundancy module of methanol.
By storing methanol subsea, the station sizes will reduce correspondingly.	Response time on methanol injection is longer compared to when methanol is stored and injected subsea.
-	HSE conditions for workers on the FPSO will worsen due to the potential hazards by methanol storage.

3.5 Distribution Schematics

Simple schematics for distribution are presented in the following subsections. Schematics for the chemical injection modules, the distribution system in the SCS&I-station and flowlines from station to X-mas tree are designed. All valves considered in the design are fail-safe in order to maximize safety of the system, as discussed in Subsubsection 2.4.6.4. All connections considered are horizontal to make SCS&I-station and tank modules design as simple as possible. Even though vertical connection systems offer shorter connection time, they are not considered as they may make the system design more complicated than horizontal connection designs. The distribution designs are maximized with respect to availability, reliability and redundancy to minimize the risk and consequence of chemical injection failure, resulting in chemical remedial actions.

3.5.1 Tank Module for Production Chemicals and LDHI

Corrosion inhibitor, scale inhibitor, asphaltene inhibitor, demulsifier and biocide are injected with low rates, ranging from 6 to 20 l/hr. LDHI is also injected with relatively low rates, ranging from 250 to 1250 l/hr. The required pump power for each low rated chemical is highlighted in Table 3.24 (Peyrony and Beaudonnet, 2014). The pump powers are assumed to accommodate one well supply, corresponding to the required pump power of one module. The pump power required for these chemicals are so low that the chemical injection pumps can use the 1 kV standard electric network. This is the same as for other subsea production system equipment.

Table 3.24: Pump power required for low-rate injection chemicals.

Chemical	Pump power required[kW]
Scale inhibitor	0,1
Asphaltene inhibitor	0,1
Corrosion inhibitor	0,1
Demulsifier	0,1
Biocide	1
LDHI	10

A simple process diagram of a tank module for these low rate injection chemicals is shown in Figure 3.14. Injection of production chemicals are critical for the oil production, it is therefore important to avoid downtime of the chemical injection system. In order to maximize availability, reliability and redundancy to the system, the chemical injection pumps are coupled in an active parallel redundant system. Each pump in the circuit operates at 50% of maximum volume rate capacity, delivering required chemical supply demand at all times. If one pump fails, the other immediately takes over and has the capacity to operate at 100% of required supply demand. The valve arrangement will redirect the flow if a failure event occurs. Ball valves and gate valves were considered for these valve applications. Gate valves are preferred because they offer a more reliable design than ball valves. The valves are used in on-off applications, and if frequent opening/closing operations are required, the ball valve may leak due to friction between ball and seal. A design requirement is that the system has to be modularized so that equipment needing maintenance and replacement, such as injection pumps and storage tanks, can be retrieved to surface. Connections close to the bladder tanks, distribution system and chemical injection pumps are therefore incorporated. Clamp connection systems are chosen for these connections due to their relatively small connection sizes, easy handling and short installation time.

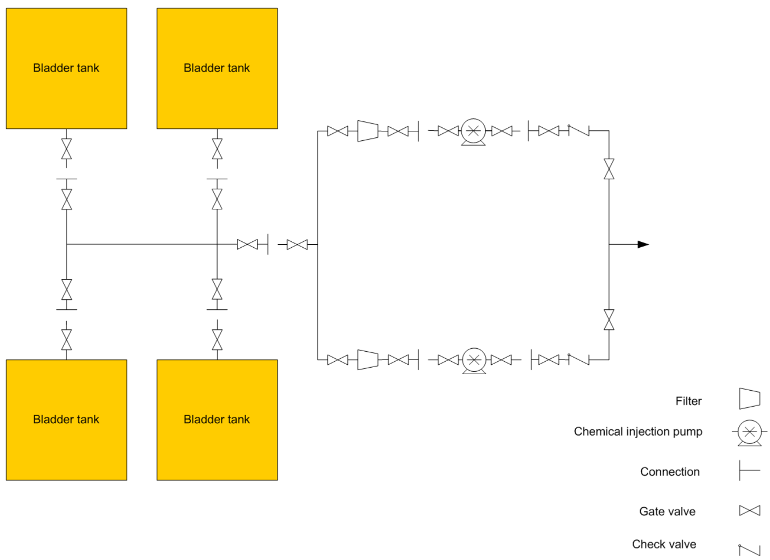

Figure 3.14: Tank module.

A filter is located upstream of each pump to filtrate the chemicals for solids. There are several reasons why filters should be applied, the most important are:

- Filtrate the production chemical before it enters the chemical injection pump, small solid particles have the potential to erode critical components in a pump.
- By filtrating the production chemical, the risk of blockages in the chemical injection lines are minimized. Although solids in the production chemicals are present in small amounts, they have the potential to completely block a chemical injection line over time (Stables, 2010).

Check valves are placed downstream of the chemical injection pumps to prevent any backflow through the pumps. The chemical transportation pipelines used inside the module are rigid. Rigid pipes are significantly cheaper to manufacture than flexible pipes, and they offer high reliability if the material selection is made properly.

3.5.2 Tank Module for Methanol Injection

The modules storing methanol are designed slightly different than low-rate injection chemical modules. This is due to the high injection rates required. Once a shutdown/start-up operation is initiated, injection rates of 5000 to 25000 l/hr is supplied to lower the hydrate formation temperature in the subsea field. The required pump power for methanol injection is 250 kW. These pumps require the use of a dedicated 20 kV HV electric network (Peyrony and Beaudonnet, 2014).

3.5.2.1 Methanol Module for Subsea Storage

If subsea storage of methanol is the opted solution, the process diagram will be similar to Figure 3.14. A dual active redundancy system is assumed to be sufficient with respect to operational demands and availability. The methanol pumps must deliver 250 kW, resulting in large added mass by having two identical 250 kW pumps working in parallel. To enable weight reduction, it is decided to have one 250 kW pump in parallel with a 125 kW pump. During operation, the 250 kW pump is running at 50% capacity while the 125 kW pump is running at maximum capaxity (100%). If the 125 kW pump fails, the 250 kW pump will be running at maximum capacity ensuring required methanol supply. If the 250 kW pump fails during operation, other methanol modules on the station will start to pump methanol, satisfying the amount of methanol needed.

3.5.2.2 Methanol Module for Topside Storage

By storing methanol topside, two redundancy modules are required to satisfy one shutdown and one start-up operation in the event of methanol flowline failure. The design in these methanol modules are slightly different than for subsea storage of methanol. To ensure maximum availability, reliability and redundancy of these modules, it is decided to have three 125 kW pumps in a passive parallel redunant system, shown in Figure 3.15. Two pumps are running at maximum capacity the same time to provide the injection rate required. If a failure occurs in one of the operating pumps, the pump is isolated by the valve arrangement and the third pump takes over immediately.

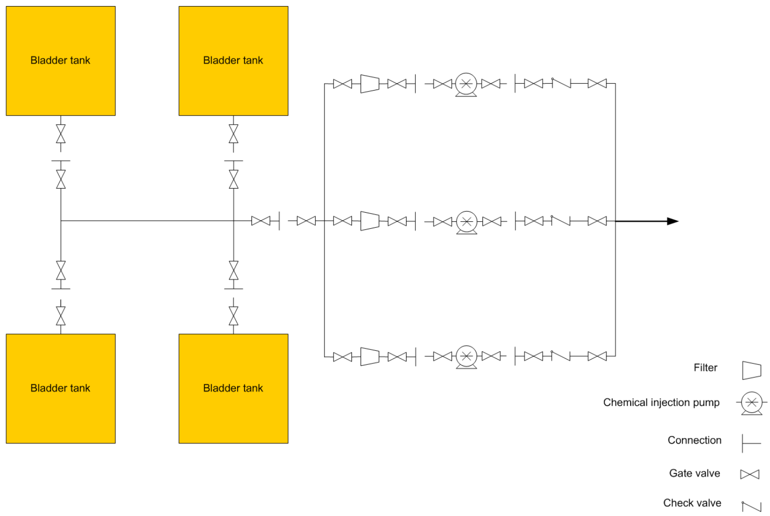

Figure 3.15: Tank module for redundancy methanol.

3.5.3 SCS&I-station Schematics

The chemical distribution principle of the SCS&I-station does not change whether a centralized or a decentralized system architecture is preferred. Note that the number of tank modules and associated chemical lines increases from a decentralized to a centralized system architecture. Figure 3.16 illustrates the distribution system, where number of modules are randomly chosen. The aim of this section is to illustrate the distribution principle of the station.

Each chemical has its own dedicated line from the chemical module to the multibore connector. To avoid confusion, the control and distribution unit is not included in the schematics. For low-rate injection chemicals, two spare lines drawn in blue are present in case of failure in one of the main lines. To avoid chemical contamination after spare line usage, spare lines must be flushed. If a failure occurs in one of the main methanol injection lines, the chemical flow is redirected to another methanol line with the use of valve arrangements.

It can be seen in Figure 3.16 that each module has its own connection. This connection must be extremely robust and solid as tank modules will be changed out every 6 months. The connection system must be designed in a way that allows the tank module change-out operation to be time efficient. Due to these requirements, clamp type connectors are preferred. They are relatively small, easy to handle and have a short installation time. A short description of clamp connection systems is given in Subsection 2.7.3.1

Ball valves and gate valves were considered as valve type in the arrangement. Gate valves are chosen in the valve arrangement because they offer a more reliable design than ball valves. The valves are used in on-off applications, and if frequent opening/closing operations are required, the ball valve may leak due to friction between ball and seal. The chemical transportation pipelines inside the station must have long design life. A rigid pipeline that offers excellent chemical handling properties is proposed, such as UNS S32205 duplex stainless steel.

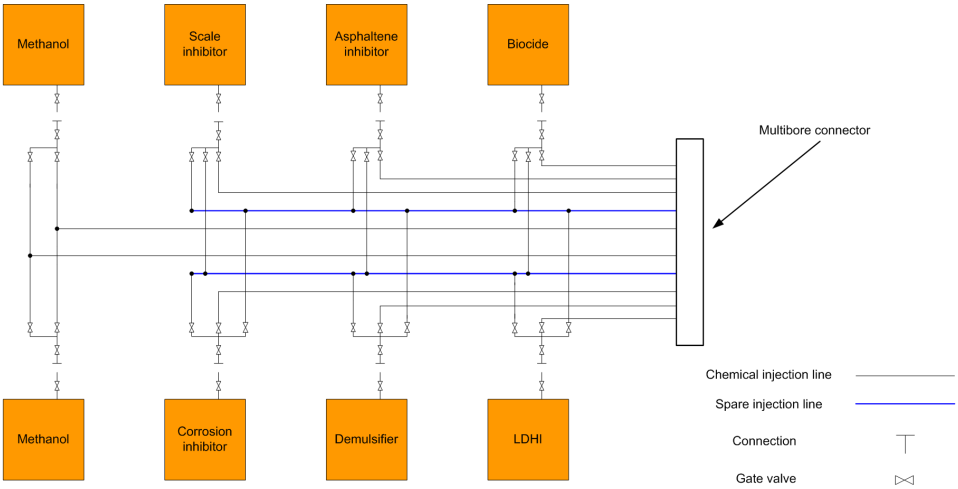

Figure 3.16: Chemical distribution on a SCS&I-station. The sizes of the equipment are not relative to each other.

3.5.4 SCS&I-station to X-mas Tree

Figure 3.17 shows how the chemicals are distributed from the SCS&I-station to the X-mas tree. One multibore collet connector connects the multibore pipe bundle at the SCS&I-station and one multibore collet connector connects the multibore pipe bundle at the X-mas tree. The chemicals are then transported to their designated injection points inside the tree. Some chemicals must be injected downhole at the production packer, while some of them are injected in the production flow at the tree, as highlighted in Subsection 2.5.8. This is however outside the scope of this thesis, and therefore not shown in the figure.

The chemical injection lines that connects the SCS&I-station and X-mas tree have small diameters, typically 2” for methanol injection lines and 0,75” for the other chemicals. Table 3.25 provides the diameters of the chemical injection lines presented in the previous section. The chemical injection lines are susceptible to several degradation mechanisms such as, erosion, corrosion, wear and fatigue. The lines are flexible and they are gathered into a multibore pipe bundle, which can be seen in Figure 3.17. The likelihood of dropped objects or other potential damaging sources are present to the multibore pipe, and has to be dealt with. Flexible flowlines are preferred as they offer excellent erosion, corrosion and collapse resistance and fatigue life. They are also easier to install than rigid flowlines, as they do not have the need for highly precise manufacturing tolerances.

Table 3.25: Chemical injection lines.

Chemical	No. of lines to each X-mas tree	Pipe size (in)
Methanol	2	2
LDHI	1	0,75
Corrosion inhibitor	1	0,75
Scale inhibitor	1	0,75
Asphaltene inhibitor	1	0,75
Demulsifier	1	0,75
Biocide	1	0,75
Spare lines	2	0,75
Total number of chemcial injection lines	**10**	

The reason for choosing multibore connectors at each termination end is to reduce the number of connections required, potential of leakage and connection operation endurance. A connector is a weak link in a system due to the potential of leakage, and by having less connectors the probability of leakage reduces. A collet multibore connector is chosen due to its easy handling of larger pipes and ability to handle larger misalignment compared to a clamp connector (Damsleth et al., 2012). The subsea field development lies at a depth of 500 m, making bolted flange connectors problematic to apply. Divers are normally used to fasten the several bolts in this connection system. Hence, bolted flange connectors should be considered on shallower depths. Since the multibore pipe bundle is relatively large, the multibore collet connectors are horizontal. With vertical connection systems, the weight acting on the structures from the multibore pipe bundle may be excessive, as described in Subsection 2.7.1.

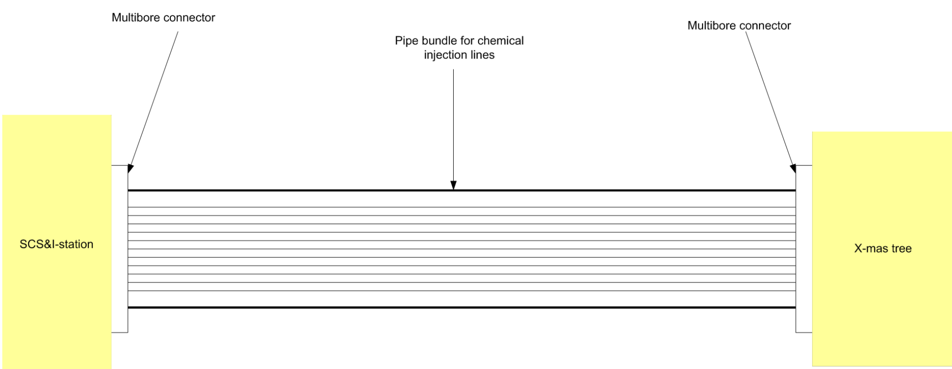

Figure 3.17: Multibore pipe bundle for chemical injection lines from SCS&I-station to X-mas tree.

3.6 Economic Analysis

In this section, an economic analysis of Case 1 and Case 2 from Section 3.4 is conducted by using a well known Industry Cost Database. A supplementary document containing detailed calculations of the analysis may be released upon request (Lundal and van Dijk Festøy, 2017). The analysis aim towards the economic feasibility of storing methanol topside instead of subsea. The economic analysis is limited to material selection, installation and maintenance cost of the methanol injection flowline and tank module change-out costs. In Section 3.1 it was found that methanol occupies 60% of the storage capacity on a SCS&I-station. Methanol requires 15 tank modules while the other chemicals only require 10 in total. If cost saving measures are possible by storing methanol topside, this seems like a reasonable solution. Only the tight cluster well configuration with a centralized system architecture is considered. A list of assumptions used in the analysis is given:

- The subsea field is located offshore West Africa. Average basin and metocean data is selected in the Industry Cost Database because specific field location is unknown.
- Life of subsea field is 20 years.
- To keep OPEX to a reasonable level, refill operations must be feasible from an MPSV that already performs inspection, maintenance, and repair tasks at the site (Chilloux et al., 2012). Mobilisation, demobilisation and transit loadout costs of MPSV are therefore neglected.
- Module installation time is equivalent with retrieval of depleted storage tank modules.
- Storage tank modules are depleted when retrieved at the end of every period.
- Tank module retrieval and deployment takes the same amount of time.
- Mobilisation and demobilisation of pipelay vessel and DSV (Diving Support Vessel) for tie-in operation of methanol injection flowline are not taken into account. It is assumed that all subsea equipment is installed in one campaign.
- The installation method used for the methanol injection flowline is S-lay with dynamic positioning.
- Weather downtime is 7% for pipelay vessels. For DSV and MPSV it is 10% (Retrieved from Industry Cost Database).

3.6.1 Material Selection of Methanol Injection Flowline

The methanol injection flowline can be constructed with either carbon steel, UNS S31600 austenitic stainless steel or UNS S32205 duplex stainless steel (Standard Norge, 2002). Carbon steel has the advantage that capital costs are low, but it has the disadvantage of higher life cycle cost due to increased maintenance and costs associated with corrosion protection. Stainless steels have higher capital costs than carbon steel, but offers lower life cycle maintenance cost, and reduced likelihood of methanol contamination (Methanol Institute, 2016a). A major difficulty with conventional austenitic stainless steels is susceptibility to Chloride Stress Corrosion Cracking (CSCC). Because manufacturing and fabrication are more difficult for duplex steels they are usually more expensive than conventional austenitic stainless steels. If CSCC is an issue, UNS S32205 duplex should be selected in place of UNS S31600 (Methanol Institute, 2016b). In this case however, CSCC is not assumed to be a problem.

Cost estimates for each of the potential construction materials of the 6" 30 km long methanol injection flowline is presented in Table 3.26, Table 3.27 and Table 3.28. The data is collected from the Industry Cost Database.

Table 3.26: Total life cycle cost for a 6" Carbon steel methanol injection flowline.

Material: Carbon steel X80, D=6"	**Quantity**	**Unit rate**	**Cost**
Linepipe	30 km	$63 400	$1 902 000
Coating	30 km	$24 000	$720 000
Anodes	15,9 te	$10 000	$159 000
Total material cost	-	-	$2 781 000
Pipelay spread	17 days	$519 000	$8 823 000
Diving support vessel tie ins	4 days	$220 000	$880 000
Diving support vessel test & commissioning	2 days	$220 000	$440 000
Testing & commissioning equipment	2 days	$35 000	$70 000
Weather downtime	2 days	-	$756 610
Total installation costs	-	-	$10 969 610
CAPEX	-	-	$13 750 610
OPEX	20 years	$49 000	$980 000
Total life cycle cost	-	-	$14 730 610

Table 3.27: Total life cycle cost for a 6” UNS S31600 methanol injection flowline.

Material: UNS S31600, D=6”	**Quantity**	**Unit rate**	**Cost**
Linepipe	30 km	$282 000	$8 460 000
Coating	30 km	$24 000	$720 000
Anodes	15,9 te	$10 000	$159 000
Total material cost	-	-	$9 339 000
Pipelay spread	30 days	$519 000	$15 570 000
Diving support vessel tie ins	8 days	$220 000	$1 760 000
Diving support vessel test & commissioning	2 days	$220 000	$440 000
Testing & commissioning equipment	2 days	$35 000	$70 000
Weather downtime	3,3 days	-	$1 316 900
Total installation costs	-	-	$19 156 900
CAPEX	-	-	$28 495 900
OPEX	20 years	$118 000	$2 360 000
Total life cycle cost	-	-	$30 855 900

Table 3.28: Total life cycle cost for a 6” UNS S32205 methanol injection flowline.

Material: UNS S32205, D=6”	**Quantity**	**Unit rate**	**Cost**
Linepipe	30 km	$394 600	$11 838 000
Coating	30 km	$24 000	$720 000
Anodes	-	-	-
Total material cost	-	-	$12 558 000
Pipelay spread	30 days	$519 000	$15 570 000
Diving support vessel tie ins	8 days	$220 000	$1 760 000
Diving support vessel test & commissioning	2 days	$220 000	$440 000
Testing & commissioning equipment	2 days	$35 000	$70 000
Weather downtime	3,3 days	-	$1 316 900
Total installation costs	-	-	$19 156 900
CAPEX	-	-	$31 714 900
OPEX	20 years	$152 000	$3 040 000
Total life cycle cost	-	-	$34 754 900

The life cycle costs in this case is by far lowest for carbon steel, which deviate from the the theory presented above. In Section 4.6 the uncertainties regarding these calculations will be discussed. It is important to choose the material that intersect technical suitability with economic feasibility. In this case, it is assumed that methanol contamination is unlikely. Carbon steel is therefore selected as methanol injection flowline material.

3.6.2 Cost Estimate of Topside vs Subsea Methanol Storage

The life time of the subsea field is assumed to be 20 years. The findings of the previous subsection is incorporated into the cost estimates when methanol is stored topside on the FPSO. The duration of a tank module installation is 6 hours, assuming 70 tons module weight and water depth of 500 metres. The installation time was given by Erik Femsteinevik from Subsea 7, the email-correspondence is given in Appendix B. According to the Industry Cost Database, the MPSV day rate is $170 000. The results of the cost estimation are presented in Table 3.29.

The cost savings of storing methanol topside is estimated to be approximately $41 000 000. This indicates that the most cost effective solution is to store methanol topside. The cost saving measures are high, implying topside storage of methanol as the best solution. This will also contribute to significant SCS&I-station size reduction, as illustrated in Figure 3.3. Further discussion of cost estimate procedure and opted solution is given in Section 4.6.

Table 3.29: A presentation of the total costs having methanol stored either subsea or topside during 20 years of subsea field life service.

	Subsea storage	**Topside storage**
Installation cost per module	$42 500	$42 500
Module installation cost per 6 months	$1 062 500	$425 000
Module retrieval cost per 6 months	$1 062 500	$425 000
Weather downtime	$212 500	$85 000
Total costs per 6 months	$2 337 500	$935 000
Total installation cost modules	$93 500 000	$37 400 000
Flowline installation with OPEX	-	$14 730 610
Total field life cost	$93 500 000	$52 130 610

Chapter 4

Discussion

4.1 Calculation of Total Storage Tank Volume

The total storage tank volume required highly depends on the injection flow rates of the different chemicals. The chemical injection rates used in the calculations of Section 3.1 are assumed to be typical injection rates. By choosing the base case for production chemicals and maximum case for hydrate inhibitors a total storage tank volume of 723,6 m^3 was estimated, resulting in 25 tank modules.

The maximum case of hydrate inhibitors was chosen to maximize availability and to minimize the potential risk of hydrate prevention failure and remedial actions. To account for the unknown duration and number of shutdown/start-up sequences throughout a 6-month period, a large storage capacity is needed. Methanol is injected at high rates, occupying 60% of the station total storage capacity. Topside storage of methanol was therefore investigated to mitigate station space, weight and chemical refill issues. By storing methanol topside, the station size was reduced to 12 modules containing 333,6 m^3 of chemicals. Assuring methanol injection at all times, two redundancy modules of methanol was incorporated into the system design in the event of methanol injection flowline failure. Having a topside solution heavily reduces the required number of methanol modules on-site, which was indicated in Section 3.1. If the subsea wells and manifold are of a state that they need many interventions, the need of hydrate inhibitors increases vastly. The frequent number of tank module change-out operations will be so time consuming that the economic feasibility of the SCS&I-station may be questioned if methanol is stored subsea.

4.2 Selection of Subsea Chemical Storage Tank

The criteria given in the Concept Scoring Selection are the same that are given in Peyrony and Beaudonnet (2014). Overall, the best suited pressure-balanced tank design for this application was found to be the bladder tank. Interestingly, this is different to the proposal of Total and Doris, that proposed a piston tank design. Hence, the impact of parameters with high degree of importance will be discussed further with a bladder tank design and a piston tank design.

Weight (degree of importance, 3): The piston tank design was given a score of 3 while the bladder tank design was given a score of 5. The piston tank design is compared to a bladder tank design a relatively heavy and robust construction. The MPSV is limited to a crane capacity of 70 tons. Which may cause design challenges due to a module structure containing four chemical storage tanks and a distribution system.

Chemical compatibility (degree of importance, 3): The piston tank design was given a score of 3 while the bladder tank design was given a score of 6. The piston tank design is susceptible to leakages between the two liquid zones (chemical and water) if the relatively wide piston does not move perfectly. For the piston to move perfectly, the two elastomer seals must work as intended. They are affected by the temperature and by which chemical is stored. Thus, the material of the elastomer seals must be selected to resist chemical attacks for its respective chemical. The bladders in a bladder tank are fabricated of a material that is extremely tight and resistant to the chemicals applied. Since the tanks are changed out every 6 months for inspections and maintenance ashore, leakages in the bladders due to chemical attacks are not likely to occur, resulting in a score of 6.

4.3 Architecture

4.3.1 Tight Cluster Well Configuration

From the Concept Scoring Selection method utilized in Section 3.3.5, centralized system architecture was the opted solution. The difference in scores between centralized and decentralized system architecture was however very small. This is mainly due to the small distances between wellheads and manifold. The strengths and weaknesses of the two different architectures are not exploited well enough at smaller distances. The impact of parameters with high degree of importance are discussed below:

Volume flow accuracy (degree of importance, 3): Centralized system architecture was given a score of 5 while decentralized was given a score of 6. Decentralized system architecture was given 6 in score due to close placement to the wellheads and manifold. Excellent precision in dosage of chemicals can easily be executed when the designated pumps are placed close to the wellhead/manifold. The Centralized system architecture did not get full score due to additional friction losses in the chemical injection lines.

Cost (degree of importance, 4): Centralized system architecture was given a score of 5 while decentralized was given a score of 3. The decentralized system architecture scored relatively poor in this category due to an increase in manufacturing, maintenance and refill operational costs. When the MPSV has to change its position to five different locations (four wells and one manifold) during refill operations, the expenses will rise. In a centralized system architecture, the MPSV will perform its refill operation at one location.

Weight (degree of importance, 3): Centralized system architecture was given a score of 2 and decentralized was given a score of 4. In a centralized system architecture, the structure foundation is large and heavy. This raises issues regarding transportation, immersion and installation of the main structure, and a larger installation vessel is presumed. When a decentralized system is present, a smaller installation vessel is required due to smaller structure foundations, resulting in a higher score.

4.3.2 Wide Cluster Well Configuration

When the flowline distances from wells to manifold increase, the best option is decentralized system architecture. An interesting observation is that the difference in score is considerable for wide cluster solutions. This is due to the increase in impact of strengths and weaknesses for each system architecture. The impact of parameters with high degree of importance will be discussed further:

Volume flow accuracy (degree of importance, 3): Centralized system architecture was given a score of 2, while decentralised was given a score of 6. An increase in flowline distances has no impact on a decentralized system architecture, because the subsea stations are located close to their injection points. This is one of the main advantages of having a decentralized system architecture. The volume flow accuracy remains excellent in this system. In contrast, the volume flow accuracy for the centralized system architecture reduces dramatically. This is due to the considerable distances from the chemical injection pumps to the designated injection points. The injection chemicals encounter friction losses, and the ability to maintain precise dosage of chemicals becomes difficult.

Cost (degree of importance, 4): The centralized system architecture was given a score of 4, while decentralized was given a score of 3. The difference in cost from a tight to a wide cluster well configuration for a centralized system architecture is relatively low. The chemical injection pumps have to be dimensioned accordingly to accommodate for the increased flowline distances. Manufacturing costs will also rise. For a decentralized system, it is assumed that the increase in cost is negligible.

Weight (degree of importance, 3): The weight of the two architecture developments are unaffected by the increase in flowline distances. The scores are therefore equivalent to the case for tight cluster well configuration.

4.4 Distribution Solutions

One of the greatest advantages by storing methanol subsea, is the reduced response time if shutdown/start-up operations are required. By reducing hydrate inhibitor response time, the likelihood of hydrate formation decreases. On the other hand, a weakness of subsea storage is that 60% of the tank modules at the SCS&I-station are containing methanol. Meaning that refill-operations will mainly be used to retrieve and deploy methanol modules.

When methanol is stored topside, a distribution unit is required subsea. The aim of the unit is to distribute methanol to its designated injection points. In a tight cluster well configuration this unit is designed as a sole structure. In a wide cluster well configuration, the SCS&I-station providing the manifold with hydrate inhibitors are adapted to a distribution unit. The size of this structure will be small compared to other SCS&I-stations due to its small required storage capacity.

Storing methanol topside also require redundant solutions. An extra 6" methanol injection line from the FPSO was discussed. However, this was thought to be a rather expensive solution, and the likelihood of the methanol injection flowline failure was assumed to be low. Instead, redundancy modules containing methanol was opted as bests suited solution. The modules are only taken into operation when chemical flowline failure occurs.

4.5 Distribution Schematics

Tank modules should be designed in a manner that enable cost-efficient installation and retrieval. The distribution system and individual components, such as bladder tanks and chemical injection pumps, can be separately retrieved if change-out of equipment is necessary. To have the opportunity to conduct a safe and cost-effective change-out operation of components is especially important for a decentralized system architecture where the SCS&I-stations are smaller. Fewer tank modules are present, and the availability and reliability of each tank module need to be maximized.

The distribution schematics provided in Section 3.5 show simple principles of distribution systems and placement of equipment. Three different tank modules are presented; one for low rated injection chemicals and two for methanol injection. The differences between them are the chemical injection pump set-up. For low rate injection chemicals, the pumps required are relatively small. This means low cost by having two similar pumps in an active parallel redundancy system. For the standard methanol modules, two pumps with different capacities are placed in a dual active redundancy system. Weight is a critical parameter due to the 70 tons crane restriction on the MPSV. Therefore, the module has one pump that can deliver 250 kW and one that can deliver 125 kW, thereby reducing weight. If one of the pumps fail, availability of methanol injection is ensured due a to large capacity of methanol modules on the SCS&I-station. Regarding the methanol redundancy modules, three 125 kW pumps are placed in a passive parallel redundant system. It is of high importance that these modules are robust and reliable. If these tank modules fail to deliver methanol on demand, hydrate prevention is not ensured.

The schematics of the chemical distribution system within a SCS&I-station is shown in Figure 3.16. In design, optimization of placement of tank modules and equipment are conducted in order to reduce the size of the SCS&I-station as much as possible. It may be questioned if two spare lines are sufficient redundancy for the chemicals. It has been assumed that if a spare line must be used, corrective maintenance actions will take place as soon as possible.

4.6 Economic Analysis

The analysis concluded with considerable cost savings choosing topside storage of methanol. The cost savings of storing methanol topside instead of subsea was estimated to \$41 000 000. The subsea solution is costlier due to the high frequency of tank module change-out operations. In the calculations, it was assumed that all tank modules were emptied at the end of each refill cycle. Throughout a subsea field life of 20 years this means 40 refill operations. The total costs of one refill operation are 2,5 times higher for subsea methanol storage compared to a topside solution. Having 15 more modules to be changed-out at every refill operation storing methanol subsea makes considerable impact on the overall cost. The assumption of supplying total storage capacity at every 6-month period may be excessive due to uncertainties regarding methanol injection. For instance, if the true methanol usage is averaging on 70% of the methanol storage capacity, the associated costs with refill operations will reduce, making a subsea solution more economic viable. Tank modules must therefore be designed to enable storage of chemicals over several refill intervals.

An interesting discovery made was how small the costs of having a methanol injection flowline was compared to the expenses of change-out operations throughout the subsea field life. This indicates that a methanol injection flowline would be beneficial to implement in the system. From Section 3.6, theory discussing life cycle costs in relation to the different flowline materials was presented. It issued that carbon steel had higher life cycle costs than UNS S31600 and UNS S32205, which was not accurate according to the Industry Cost Database. OPEX was two times higher for UNS S31600 and three times higher for UNS S32205. Subsea flowlines are, in theory, designed to avoid major maintenance interventions during its operational lifetime. The cost estimates retrieved from the Industry Cost Database are based on experience, and it is presumed that the difference in OPEX is affiliated with equipment needed to do minor maintenance operations. The OPEX are however much smaller than CAPEX for the methanol injection flowline making minor impact on the overall cost.

The purpose of the economic analysis was to indicate whether a topside or subsea storage solution for methanol was beneficial. The analysis therefore only considered some economic aspects regarding the SCS&I-station. The main reason for developing the SCS&I-station are cost saving measures. Storing methanol topside seems like a reasonable cost saving measure improving the subsea chemicals storage solution proposed.

4.7 Weaknesses of Design and Proposed Solutions

There are some weaknesses of the system design developed that need to be addressed.

1. Weaknesses of the module design presents itself in a decentralized system architecture. If the chemical injection rates given are assumed to suffice for all wells, only one module of each production chemical will be present on each SCS&I-station. This means that during a refill operation, the wells will not be supplied with production chemicals for a specific amount of time. The production flow should always be supplied with production chemicals. Improvements of design may be:

    - To change out bladder tanks one by one instead of whole tank modules. This ensures continuous injection of production chemicals at all times. A challenge with this proposal is that the duration of refill operations will increase, and it may not be economic feasible, especially in deeper waters.
    - Have one larger tank module on the station that stores one tank of each production chemical. Chemical injection from this module is only done when a tank module change-out is performed, ensuring continuous supply of production chemicals. This tank module can be changed-out during normal operation.
    - Equipment should be independently retrievable, ensuring no downtime on chemical injection dependant equipment. Equipment on the tank modules are monitored carefully by sensors giving real time data to the operators. Hence, the condition of the operational equipment is always known. If equipment are degraded, maintenance operations are planned and executed to avoid chemical injection failure.

2. One of the requirements regarding design is that the storage tank capacity of the tank modules are 30 m^3. Another is that tank modules are changed-out at a 6 month interval. For a decentralized system architecture, only half a module is injected throughout a 6-month interval concerning production chemicals. A cost saving measure would be to prolong the change-out interval to one year to avoid unnecessary change-out operations.

4.8 Uncertainties

There are several uncertainties that needs to be addressed in this thesis.

1. Long-term storage of chemicals subsea is not common in the petroleum industry. Limited theory obtained online and through scientific reports made the concept selection difficult. Several assumptions were made, and the use of intuition was extensively used to give scores. The scores are based on

qualitative work, and some calculations may have been incorporated to make the final scores more trustworthy. One may argue that some of the chosen parameters are less important than others, or that other parameters should have been assessed.

2. The assumptions made regarding shutdown/start-up time to the calculation of storage tank volume is highly uncertain. Little or no information regarding shutdown/start-up sequences were found.

3. Assumptions made regarding sizes of tank modules and their placement on the SCS&I-station was made using intuition. The spacing used and their placement may be optimized.

4. The tank module change-out duration made is dependant on water depth, structural design, vessel equipment available and environmental conditions. Uncertainties regarding module change-out time has to be taken into account, as they heavily influence the operational costs.

5. The economic analysis provide indicative estimates only. Many assumptions were made, making the calculations uncertain.

6. Standards are rarely used in this thesis. According to the International Association of Oil&Gas Producers (IOGP), industry standards are used to "...enhance technical integrity, improve safety, enable cost reductions and reduce the environmental impact of operations worldwide." (IOGP, 2017). By utilizing standards more often in this thesis, the information and results provided would have been more trustworthy. Verification of results according to appropriate standards are therefore recommended.

Chapter 5

Conclusions

The need for more cost-efficient solutions in the oil and gas industry formed the background of this thesis. The SCS&I-station has the potential to reduce the life cycle cost of subsea production systems. By storing and injecting chemicals subsea, the petroleum industry is one step closer to mitigate the need of topside facilities when producing oil and gas.

Using production data from a field case given by Total and Doris, the total storage tank volume of the SCS&I-station was estimated to 723,6 m^3 when storing methanol subsea. The number of modules required was 25, and the corresponding station size measured 40×27 metres. It was found that methanol occupies 60% of the total storage volume. By storing methonal topside the required storage capacity subsea is reduced to 333,6 m^3. The required number of storage tank modules decreased correspondingly to 12, having two methanol modules present for redundancy purposes. The station size was reduced to 29×20 metres.

Based on the principle of Concept Scoring, it was found that a pressure-balanced bladder tank design was better suited for this application than the piston tank design, proposed by Total and Doris. The bladder tank solution was selected due to its low weighted construction and excellent chemical compatibility.

It was found that a centralized system architecture is best suited for tight cluster well configurations, while a decentralized system architecture is preferred for wide cluster well configurations. Changing system architecture design to chosen well configuration strengthen the SCS&I-station applicability.

The distribution schematics was developed to satisfy the functional specifications given by the injection chemicals. Using the bladder tank design, it was found that a dual active redundancy system with two pumps in parallel was best suited for low-rate injection chemicals. Methanol injection modules was designed similarly, but having pumps with different injection capacities present for weight reducing measures. Methanol modules are also present as redundancy modules in the case of topside methanol storage. In that case, there are three pumps in a passive parallel redundant system, ensuring methanol availability at all times. Also, distribution schematics illustrating the chemical distribution inside the SCS&I-station was developed. Multibore connectors was chosen at the end terminations from the SCS&I-station to the injection points by having a flexible pipe bundle.

The results from the economic analysis indicated that topside storage of methanol would be beneficial. A methanol injection flowline made of carbon steel was selected as it satisfied technical suitability requirements and was by far the least expensive construction material. The cost savings of storing methanol topside was estimated to $41 000 000.

Chapter 6

Recommendations for Further Work

The research towards a possible SCS&I-station solution is at an early stage, and further research must take place to commercialize this concept. Recommendations for further work is based on subjects not studied, or sufficiently examined.

Improvement of Existing Work

- Investigate alternative designs of module and SCS&I-station by the means of equipment positioning. To condense the station even more, one may design the SCS&I-station over two levels, where piping and valves are located at the lower level. Only the tank modules and control unit are located at the upper level having vertical connection systems incorporated. The equipment should be placed in close proximity to each other to reduce station size as much as possible.
- A thorough evaluation of calculations regarding strengths and weaknesses of the system architecture is required. Special consideration should be given to the parameters given high degree of importance.
- Optimize design regarding tank module change-out operations, as the wells must always be supplied with production chemicals. Special consideration should be given when only one module of chemicals is present.
- Include more parameters into the economical assessment provided to make it more accurate.

Further Work

- Assess alternative materials for construction and manufacturing purposes to lower station and module weight. For refill operations, a 70 tons requirement has to be satisfied restricting module weight. Aluminum should be of special interest as its weight is approximately 2700 kg/m^3 while steel is 7850 kg/m^3.

- Research on chemical injection pumps has to be conducted in order to use them subsea. As of today, only topside chemical injection pumps exist.
- An economic analysis of a decentralized system architecture should be investigated to better understand the potential of subsea chemical storage in this architecture solution.
- Investigate the possibility of mixing chemicals. This could result in storage and injection of several chemicals per module and potentially reduce the size of the SCS&I-station, number of chemical injection pumps and chemical injection lines required.

Appendices

Appendix A

Storage Tank Volume Calculation

This appendix presents the spreadsheets which document the calculations conducted. The tables list chemical injection rates, necessary tank volumes required and number of modules.

Continiuously injected chemicals

Chemical	Min case [*l/hr*]	Min case [*l/hr*]	Min case [*l/hr*]
Corrosion inhibitor	6	13	20
Scale inhibitor	6	13	20
Demulsifier	6	13	20
Asphaltene inhibitor	6	13	20

Periodically injected chemicals

Chemical	Min case [*l/hr*]	Base case [*l/hr*]	Max case [*l/hr*]	Duration [*hrs/week*]
Methanol	5000	15000	25000	-
LDHI	250	750	1250	-
Biocide	180	-	-	5

Tank modules

Chemical	Min case	Base case	Max case	Periodically min case	Periodically base case	Periodically max case
Corrosion inhibitor	0,88	1,90	2,92	-	-	-
Scale inhibitor	0,88	1,90	2,92	-	-	-
Demulsifier	0,88	1,90	2,92	-	-	-
Asphaltene inhibitor	1,00	2,00	3,00	-	-	-
Biocide	-	-	-	0,78	-	-
Methanol 18 hours/6 months	-	-	-	3	9	15
LDHI 18 hours/6 months	-	-	-	0,15	0,45	0,75

Appendix B

Email Correspondence

This appendix presents the email correspondence held with Erik Femsteinevik from Subsea 7 regarding tank module installation time.

VL

Vegard Lundal
on 10.05, 15:13

Hei!

Jeg og en medstudent er i gang med Masteroppgave innenfor subsea ved NTNU. Vi undersøker om det er økonomisk gunstig å plassere en lagringsstasjon med kjemikalier nært produksjonsfeltet istedenfor å benytte konvensjonell umbilical-løsning. I forbindelse med oppgaven har vi behov for å vite ca installasjonstid av subseautstyr. På stasjonen skal lagringstankene plasseres på moduler, hvor hver modul veier ca 75 tonn. Innstallasjonsfartøy er av MPSV type med 75tonns krankapasitet. Vanndyp er på 500 meter.

Har du noen grove estimater på hvor lang tid det vil ta å innstallere en slik modul?

Hadde satt stor pris på om du hadde hatt anledning til å hjelpe oss. Eventuelt videresende e-posten til korrekt fagperson innad i selskapet.

Med vennlig hilsen,
Vegard Lundal

EF

Erik Femsteinevik <erik.femsteinevik@subsea7.com>
ma 15.05, 10:41
Vegard Lundal

Svar alle

Hei Vegard,
Typisk vil ett slikt løft ta 6 timer, med klargjøring av struktur på dekk, løft over dekk, gjennom plaskesonen og ned til 500m samt frakobling av rigging under vann. Men når det er sagt så er dette helt avhengig av hvordan strukturen ser ut. Er det stort added mass areal på strukturen må den senkes rolig f.eks for å forhindre slakk rigging.

Dersom modulene skal håndteres gjennom Module handling Systems (MHS) på typsisk IMR fartøy (http://www.subsea7.com/content/dam/subsea7/documents/whatwedo/Fleet_2017/Seven%20Viking.pdf) for høyere sjøtilstand og generelt mer robust løsning, så må strukturen slankes ned til 60-70Te max dynamisk last.

Disse IMR båtene er ofte på fast kontrakt med oljeselskapene og går rundt på feltene mer eller mindre kontinuerlig.

Regards,

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