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Subsea Chemical Storage and Injection Station - Single Line Batch Re-Supply of Chemicals

Operation Strategies and System Design

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Summary

The offshore industry is facing many challenges when it comes to maintaining operational efficiency. One of the biggest problems are related to flow assurance problems. To avoid such issues, different chemicals are transported through individual lines in an umbilical from topside into a x-mass tree or a manifold. Total has for some years worked on a new concept where they want to replace the traditional umbilical with big tanks that are stored on the seabed, which are refilled every sixth month. However, if it is possible to simplify this, then the capital cost would be reduced even more.

The aim of this thesis was to look at the operational strategy, meaning how we can transport these chemicals from one place top-side to a place subsea. Furthermore, find a solution for the design of system, both regarding chemicals being into separate tanks, and tanks that contain a mixture of two or more of the chemicals, making a so-called chemicals combination.

The approach used to answer the objectives of this thesis involves collecting relevant scientific reports and theory by search in scientific databases as well as books and other relevant sources online. Furthermore, calculations with focus on flow behaviour has been conducted. Illustrations have been used to a large extent to illustrate flow behaviours in pipelines of different diameters, and when the liquid spacer are of different length. In addition flow diagrams have been sketched to illustrate the transportation and the distribution of the chemicals.

Due to the uncertainties on how the chemical will behave when they are sent through the same line, they will be separated by a liquid spacer. Uzu et al. (2000) say that the liquid spacer can vary from 100 meters to 500 meters depending on the size of the pipeline and the length it is going to travel. However, since there are little specific knowledge on how long it should be between different chemicals, the liquid spacer has been seen as a parameter.

Based on the injection rates provided by Total for one field case, it was founded that biocide was injected at a much higher rate than the other production chemicals. It was, therefore, suggested that biocide should be injected every other time.

By sending the chemicals as combinations rather as individuals a tank module based on the chemicals being sent through a 0,5” pipeline was reduced from 16 tanks down to 10 tanks.

Sammendrag

Offshore industrien har mange utfordringer i forhold til å opprettholde effektiv drift. En av de største utfordringene er relatert til flow assurance problemer. For å unngå slike problemer blir forskjellige kjemikalier transportert gjennom individuelle rår i en umbilical fra land til et x-mass tree eller manifold. Selskapet Total har i mange år jobbet med å utvikle et nytt konsept som innebærer å erstatte den tradisjonelle umbilical med store tanker som er lagret på sjøbunnen, og som blir etterfylt hver sjette måned. Hvis dette er mulig så kostnadene ved produksjon reduseres.

Hensikten med denne mastergraden har vært å se på hvordan en kan transportere kjemikalier fra et sted på land til en sted på havbunnen. Videre å finne en låsning for et systemdesign, både når det gjelder kjemikalier i separate tanker, og tanker som inneholder en blanding av to eller flere kjemikalier, en såkalt kjemikaliekombinasjon.

For å få svare på problemstillingene har det vært søkt i vitenskapelige databaser etter relevante vitenskapelige artikler og teori. Videre har det vært søkt etter bøker og artikler i Oria. I tillegg har en funnet annen relevant informasjon på nettet. Videre har beregninger med fokus på flow behavior blitt utført. Illustrasjoner har også i stor grad blitt brukt til å illustrere flow behaviour i rørledninger med forskjellige diametere, og når væskeavstanden har hatt forskjellig lengder. I tillegg er flytdiagrammer blitt laget for åillustrere transport og distribusjon av kjemikaliene.

På grunn av usikkerhetene om hvordan kjemikaliet vil oppføre seg når de sendes gjennom samme linje, vil de bli separert av en viskøs væske. Uzu et al. (2000) sier denne væsken kan variere fra 100 meter til 500 meter, avhengig av diameteren på røret og avstanden den skal bli transportert. Ettersom det er lite spesifikk kunnskap om hvor lenge denne skal være i forholde til det ulike kjemikaliene, har lengden på denne væsken blitt sett på som en parameter.

Basert på injeksjonshastighetene gitt av Total for et gitt felt, ble det på grunnlag av biocide ble injisert med en mye høyere hastighet enn de andre produksjonskemikaliene. Det ble derfor foreslått at biocide skulle injiseres annenhver gang.

Ved å sende kjemikaliene som kombinasjoner, snarere som individer en tankmodul basert på kjemikaliene som sendes gjennom en 0,5 inch rørledning, ble redusert fra 16 tanker ned til 10 tanker.

Acknowledgement

I would like to thank my Supervisor Tor B. Gjersvik for letting me do this thesis and for his guidance and help throughout the process. In addition I will also give a thank to Sigbjørn Sangesland for his advices for furher work.

At the end I would like to thank my fellow classmates at the study hall, that have made the dark days better.

Preface

This master thesis is written at the Department of Geoscience and Petroleum, and ends a 2-year Master degree (MSc) in Subsea Technology at the Norwegian University of Science and Technology.

The thesis continuous the work conducted by Fetsøy and Lundal (2017) and Fjeldsaunet and Lund-Tønnesen (2017) looking at Subsea Chemical Storage and Injection Station (SCS&I-station) concept.

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Abbreviations

CI	-	Corrosion Inhibitor
PI	-	Parfine Inhibitor
AI	-	Asphaltene Inhibitor
AA	-	Anti-Agglomerant
KHI	-	Kinetic Hydrate Inhibitor
SI	-	Scale Inhibitor
H2S Scav	-	Hydrogen Sulfid Scavenger
EB	-	Emulsion Breacker
CMV	-	Chemical Metering Valve
CTV	-	Chemical Injection Throttle Valve
SCS&I	-	Subsea Chemical Storage and Injection
SCC	-	Sulphide Stress Cracking
HIC	-	Hydrogen Induced Cracking
MIC	-	Microbiologically Induced Corrosion
SRB	-	Sulfate Reducing Bacteria
OTS	-	Ocean Team Scandinavia as
CP	-	Centrifugal Pump
PD	-	Positive Displacement pump
ISO	-	International Organization of Standardization
NORSOK	-	"NOrsk SOkkels Konkurransesposisjon"
PIG	-	Pipeline Inspection Gauge
PIV	-	Particle Image Velocimetry
IMU	-	Inertial Measurement Unit
GVF	-	Gas Volume Fraction

CHAPTER 1

INTRODUCTION

1.1 Background

On an offshore facility where the capital costs are high, maintaining an operational efficiency is of importance. Since the subsea infrastructure is vulnerable to ow assurance issues, chemicals are being injected at different rates to prevent accidents that can shut down the production entirely. However, these chemicals come with a high price tag, so finding new solutions that can reduce these costs is of high interest. Total have for some years worked on a concept where they replace the traditional umbilical through which each chemical are transported through individual lines with big tanks that are stored subsea. The concept is that these tanks will be stored, and be replaced and maintained every six months. From these tanks the different chemicals will be injected into the well stream either continuously or in batches depending on what chemical is in use. However, what if it was another solution that could simplify this even more, then the capital cost could be even less. The aim of this thesis is therefore to see if it is possible to send all the chemicals through on single pipeline, where each chemical are separated by a liquid spacer. A simple illustration of this concept has been sketched in Figure 1.1.

1.2 Research Objectives

The objective of this thesis is to continue the work from last years project done by Fjeldsaunet and Lund-Tønnesen (2017). The objective have been split into two sub-objectives.

- Look at the operational strategy, meaning how we can transport these chemicals from one place top-side to a place subsea

- Find a solution for the design of system, both regarding chemicals being injected into separate tanks, and tanks that contain two or more of the respective chemicals, making a so-called chemical combination.

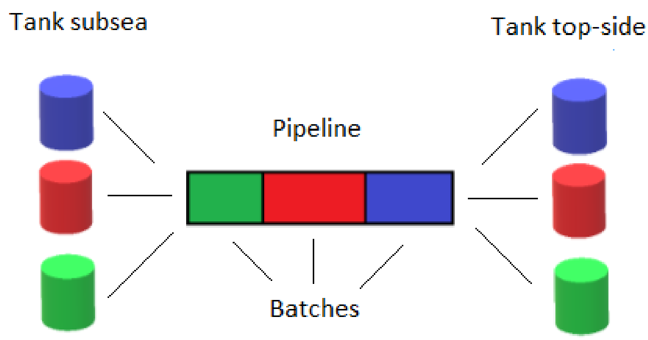

Figure 1.1: Simple illustration of chemical distribution

1.3 Limitations

Subsea engineering is a major area, especially when it comes to operations in extreme environment. There will therefore be a lot of aspects that will not be covered due to time constraints and lack of knowledge. This thesis will therefore not include:

- Any cost estimation
- Any thorough analysis of the liquid spacer

1.4 Structure of the Thesis

In chapter 2 theory that is needed to understand the work later in this thesis is presented. About 30 % of the theory presented in this thesis has been duplicated from last years project done by Fjeldsaunet and Lund-Tønnesen (2017). Some of the theory that is new gives a more deeper description of pigging with focus on a liquid spacer and the operation of pigging itself. Different methods on detecting a pig, both conventional and liquids will also be briefly presented. A new method of chemical cleaning will be introduced, as well as some on chemical compatibilities, where a company named Nalco Champion is working on the possibilities of mixing different chemicals, making so-called chemical combos.

Chapter 3 presents the methods that have been applied to carry out this thesis, and how they have been used.

Chapter 4 present the results of calculations in respect to possible dimensions of a system design. Here will most of the result be presented as will the use of illustrations to get a quick view of how different parameters can affect the flow.

In chapter 5 will a discussion around the concept on a optimal solution for how the chemicals can be transported and distributed. There are been looked at two scenarios; one where the chemicals are transported and stored in individual tanks, and when they are handled as chemical combinations. The transportation can be affected by several of the parameters. What this will mean for a final design will also be discussed.

Chapter 6 presents the main conclusions of the thesis.

CHAPTER 2

THEORY

This chapter starts by presenting different flow assurance problems that can occur when operating offshore. Furthermore factors that affect the choice of different production chemicals and the compatibility between them will be presented. As these chemicals are going to be transported through one single pipeline there are possibilities for chemicals build up along the wall of the pipeline due to pressure and temperature as the chemicals are transported from onshore facility to offshore facility. A new method of chemical cleaning will therefore be presented. At the end a deeper description of pigging with focus on a gel pig, also in this thesis called a liquid spacer, and different ways how to track and locate them.

2.1 Flow Assurance Challenges

The oil and gas industry is facing several challenges regarding formation of blockage and unstable flow along the production pipeline. This section will present a selection of the most common challenges, and how to combat them.

2.1.1 Hydrate

Gas hydrates are ice-like clathrate solids formed from water and small hydrocarbons (methane, ethane, propane, nitrogen, carbon dioxide and hydrogen sulfide) at relatively high pressures and low temperatures. They occur most commonly during drilling and production processes, and they can form anywhere at any time when water, natural gas, low temperatures, and high pressures are present (Kelland, 2014a). Figure 2.1 shows a hydrate plug that has been formed in a subsea pipeline. Hydrates can be prevented by chemical treatment which includes the use of chemical inhibitors, where methanol (MeOH) and monoethylene glycol (MEG) are the most common.

Hydrate formation can also be prevented if enough water can be removed from the production fluids. Thermal insulation aims to maintain the temperature above hydrate formation conditions. Depressurization is applied on both sides of the hydrate plug to avoid it breaking loose and becoming a dangerous projectile, but this is not a good solution for deepwater installation due to high hydrostatic pressures of the water (Kelland, 2014a). There are several methods that can increase the temperature in the pipe. For example, active heating can be applied either with electricity or using a double pipe and circulating hot fluid on the outside of the production line. One can also bury the pipe or put insulating material around it. However, heating is an expensive alternative and is mostly used only in special circumstances (Kelland, 2014a).

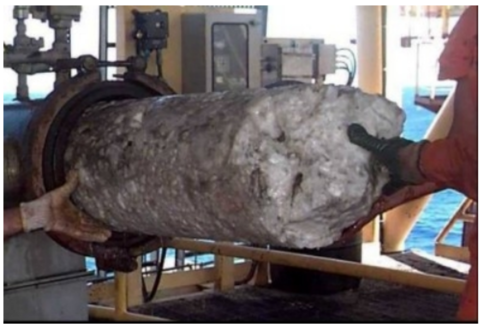

Figure 2.1: A large gas hydrate plug formed in a subsea hydrocarbon pipeline (Heriot-Watt University, 2017)

2.1.2 Corrosion

Bai and Bai (2010a) define corrosion as *the deterioration of a metal due to chemical or electrochemical interactions between the metal and its the environment* (Bai and Bai, 2010a). It can happen both internally and externally, where internal corrosion is caused by the presence of CO2, H2S, water and organic acids in production fluids. The level of corrosion depends on the environment and metal in use. External corrosion of a metal occurs due to general exposure to water or the atmosphere (Bai and Bai, 2010a).

Internal corrosion can be prevented by using internal coatings. These also reduce the friction which improves the flow efficiency. Another way to prevent internal corrosion is by injecting corrosion inhibitors. These are chemicals that reduce the corrosion rate by adsorbing themselves to the metal surface as a film. External corrosion can be reduced by either applying an organic coating or by using cathodic protection. Cathodic protection

Figure 2.2: Scale crystals in pipe (Mackay, 2008)

can work in two ways. It can work either by applying a sacrificial anode to the metal to be protected or by applying an impressed current connection between the anode and the cathode (metal to be protected). The most effective solution is a combination of these two, however, this is not always the most cost-effective solution (Bai and Bai, 2010a).

2.1.3 Scale

Scale is formed when ions in the produced water form salts due to pressure or temperature changes. These salt-crystals may precipitate on the pipe walls. The most common type of scale is formed from calcium carbonate (Bai and Bai, 2010b; Kelland, 2014b). Scale will form along the whole of the circumference of the pipe wall. If it grows sufficiently, it will effectively reduce the diameter of the pipe, and constrict the flow, as can be seen in figure 2.2. This can be identified by an increased pressure drop along the pipe.

Scale is dealt with either proactively with chemical inhibition, or reactively with regular mechanical cleaning. The most common way to deal with scale is the use of scale inhibitors (Bai and Bai, 2010b). Chemical inhibition is done either by injecting scale inhibitors into the production flow, injecting scale inhibitors into the reservoir where the inhibitors adsorb into the reservoir rock, or by depositing solid scale inhibitors in the reservoir. The latter two are called squeeze treatment, and the inhibitor is released as the reservoir is produced (Kelland, 2014b).

Chemical treatment works either by stopping the nucleation process where the scale crystals are formed or by hindering the formed crystal from growing. The latter may be achieved by the chemicals reacting with the crystal structure, or by hindering the crystals in depositing on the pipe walls. Bai and Bai (2010b) list the most common scale inhibitors as inorganic polyphosphates, organic phosphates esters, organic phosphonates, and organic polymers.

2.1.4 Asphaltene

Asphaltenes are black coal-like molecules substances found in crude oil. They tend to be sticky which makes it difficult to remove them from surfaces. Asphaltenes can be found in all oils and their stability is influenced by the pressure, temperature and certain types of completion fluids.

Asphaltene problems occur infrequently offshore but can have a severe impact on project economics. Asphaltene deposition will most likely occur in the tubing when the temperature and pressure of the produced fluids pass the bubble point. To mitigate asphaltene problems the subsea system design generally relies on bottom hole injection of inhibitors. Asphaltene deposits are very difficult to remove once they occur. Bai and Bai (2010c) write "Unlike wax deposits and gas hydrates, asphaltene formation is not reversible", however, Kelland (2014c) states that this is a controversial point, and some studies have shown that asphaltene flocculation might be reversible. Asphaltene deposition can be prevented when the asphaltene inhibitors (AI) are dosed at a very low concentration. In the absence of inhibitors, it is not uncommon with monthly cleanouts of the tubings (Bai and Bai, 2010c).

Figure 2.3: Asphaltene Solvent (SkySpring, Oil and Gas Service, Inc, 2017)

2.1.5 Emulsions

An emulsion is a mixture of two liquids where one is present as droplets suspended in another continuous liquid. Crude oil is normally produced as a water-in-oil emulsion (Kelland, 2014d). Here, water droplets are suspended in the continuous oil phase. To meet standards for selling and reduce corrosion of the pipeline, water must be removed from the oil. Traditionally, demulsifiers are added at the processing facilities, but the stability of an emulsion increases over time, and it may be more difficult to separate the liquids when they reach the separator, even when adding demulsifiers. Therefore, adding demulsifiers at the wellhead, or even downhole, may greatly improve the separation at the processing facilities (Kelland, 2014d).

Kokal (2002) mentions five different factors that affect emulsion stability: Emulsifiers present in crude oil, temperature, solids, droplet size, and pH.

Emulsifiers may exist naturally in crude oil, such as asphaltene or resins, or the emulsifying effect may come from injected chemicals. Emulsifiers are usually molecules consisting of a polar hydrophilic part and a non-polar hydrophobic part. This molecule will orient itself on the interface between the two phases, and form a film between the phases. Film forming corrosion inhibitors are often surfactants and may stabilize the emulsion. Therefore, careful selection of corrosion inhibitor may help reduce the amount of demulsifier needed (Kelland, 2014d).

Demulsification is achieved through a two-step process; flocculation and coalescence (Kokal, 2002). Flocculation is a process where droplets cling together without merging. Coalescence is the process where two or more drops merge into a bigger drop. These bigger drops are less stable and settle faster.

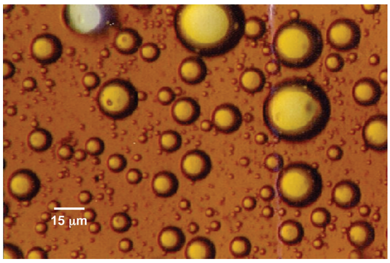

Figure 2.4: Water-in-oil emulsion (Kokal, 2002)

2.1.6 Wax

Wax is typically long-chains of alkane compounds naturally presented in crude oil. Deposition of wax on pipeline walls increases as the fluid temperature decreases. When the temperature gets below the cloud point, crystals will begin to form and accumulate on the pipe walls. Over time this results in flow restriction, or possibly a blockage of the pipeline, and thereby reducing the pipeline efficiency. (Bai and Bai, 2010c) The wax deposition thickness depends on temperature, pressure, composition of oil and velocity of the fluid (The University of Kansas, 2017).

Wax control and management are conducted either by flowline pigging, thermal heating, inhibitor injection or by coiled tubing intervention. If the wax has formed, flowline pigging is mostly used. Chemical inhibitors can also be used, but these are often not effective and they tend to be expensive. In cases where pigging is not practical, the wax deposition is controlled by keeping the temperature over the cloud point for the whole flowline. (Bai and Bai, 2010c)

Figure 2.5: Wax deposition (The University of Kansas, 2017)

2.1.7 Biocides

When practicing corrosion control there are several corrosion mechanisms to consider. One of the mechanisms are microbiologically induced corrosion (MIC), which is estimated to account for 40% of internal corrosion in the oil and gas industry (Turkiewicz et al., 2013). The most common form of MIC is sulfate-reducing bacteria (SRB) (Wen et al., 2006). These are bacteria whose metabolic byproduct is hydrogen sulfide (H_2S), which is highly corrosive, and may also bond to iron ions to make iron sulfide, a form of scale (Dickinson et al., 2005). Kelland (2014e) presents five main mechanisms to minimize reservoir souring by controlling SRB; Add biocide to kill SRB, treat SRB with a biostat, stimulate the formation of nitrate reducing sulfide-oxidizing bacteria (NR-SOB), use unsulfated aquifer or desulfated water in injection wells, and use an H_2S scavenger. Two of these mechanisms require chemical injection; biocides and biostats. Biocides are chemicals that kill the bacteria, and biostats are chemicals that hinder growth of the bacteria. Kelland (2014e) further states that the most effective application of biocides are a mix of one or more biocides, or of biocides and biostats.

There are mainly two classes of biocides Kelland (2014e); oxidizing and non-oxidizing. Oxidizing biocides work by causing oxidation/hydrolysis of protein groups in the bacteria. Non-oxidizing biocides work by disrupting the cell walls of the bacteria. Some SRB may be immune to some non-oxidizing biocides, while oxidizing biocides generally work on all SRBs. However, some oxidizing biocides may be corrosive, whereas non-oxidizing biocides are not corrosive, some may even be corrosion inhibiting. The selection of biocide treatment should therefore be planned for each field to find the optimal solution.

Figure 2.6: Pitting corrosion due to MIC in a carbon steel water pipe (Skovhus et al., 2017)

2.2 Factors That Affect the Choice of Production Chemicals

Kelland (2014) lists a number of factors that affect the choice of production chemicals. These include performance, price, stability, health and safety in handling and storage, environmental restrictions, and compatibility issues. Generally, when an operator chooses a product, they want a product that performs satisfactorily at an affordable price. This means that they may not choose the product with the best performance, but a product with a satisfactory performance to an affordable price.

During transportation and storage before injection, the production chemicals must remain stable. To avoid injection problems when the chemicals are transported through a cold environment prior to injection it is important that the chemicals do not get too viscous or freeze. On the other hand, if the field locations get hot, the products must not degrade too rapidly or undergo phase changes which in the end may affect their performance.

Many chemicals can be toxic, which will be a threat to both the environment and people, depending on the dosage and exposure time. To regulate these issues all countries have their own laws, which the producers must comply with (Kelland, 2014f).

2.3 Compatibility Between Different Production Chemicals

Figure B.1 is a matrix formed by a company called Nalco, which is a global oilfield chemical company. The matrix gives an overview of the possibilities of making a combination of different production chemicals for injecting through one single umbilical. Each combination is marked with a color indicates to what extent it is possible to make a combination of two different chemicals. The green one indicates that it would be relatively easy to make a combination. For example will scale inhibitor and corrosion inhibitor based on Nalco's tests be possible to make. To get the mixture stable and compatible, Nalco has found out that this will take approximately one year. Yellow indicates that it would be possible to make a combination, but it will require significant testing, and it may take over two years. Red on the other hand indicates that it would be difficult, or nearly impossible to make a combination. In the matrix one can see that KHI/AI and KHI/PI makes a red combination. This is because KHI is water-soluble chemistry's, whereas AIs/PIs are oil-soluble chemistry's, and oil and water do not mix too nicely. The grey boxes marked with NA indicates combinations of chemicals that are of the same chemical group. To be more precise, the boxes that are marked with NA is KHI (kinetic hydrate inhibitor) and AA (anti-agglomerant), because they are both LDHI (low dosage hydrate inhibitors).

2.4 Parameters That Effects the Transportation

When injecting chemicals over longer distances there are several factors that need to be taken into consideration. Will the chemicals withstand the applied pressure when the chemicals are transported through one single pipeline separated by a viscous gel pig? If the internal surface of the pipeline have a slightly roughness, how will this affect transport conditions such as the velocity of the fluids? Will some of the chemicals stay in the small gap that may cause minor loss of material since the force are stronger in the middle of the pipeline compared to around the inner surface of the wall? Will a temperature changes along the pipeline affect the properties of the chemicals so they work as expected? Is the chemical compatible with the pipeline material it is going to be transported through? anther issue when transporting chemicals over longer distances is that high viscosity chemicals may cause internal blockage of the pipeline. These are all questions that need to be considered when injecting chemicals into pipelines.

2.5 Chemical Injection Points

All the chemicals that are stored subsea in different tanks will either be injected continuously or batched. From these tanks the chemicals will be injection into different injection points in the well. Brimmer (2006) names two methods of delivery of the chemicals. They can either be injected by using single tubes, or using a manifold. By using the manifold one need to be aware of the different pressure from each well. This can however be solved by using a chemical injection metering valve (CMV) "which is an electrically operated flow regulator used to meter the inhibitor to the deep-set chemical injection mandrels". The CMV helps the valve to maintain a constant flow despite the change in back pressure (Brimmer, 2006). An example where the CMV is installed is illustrated in Figure B.2.

Table 2.1 gives an overview on where these are injected are injected.

Table 2.1: Chemical injection points

Chemicals	Injection points
Corrosion inhibitor	Downhole, X-mass tree, manifold (Gate Energy, 2018)
Scale inhibitor	Downhole, X-mass tree, manifold (Bai and Bai, 2010b)
Demulsifier	Wellhead, Downhole, X-mass tree (Opawale et al., 2011)
Asphaltene inhibitor	Production packer (Brimmer, 2006)
Biocide*	Downhole, X-mass tree

2.6 Chemical Cleaning

When operating offshore there is always a risk at one point that the operation can shutdown entirely. This includes all hydraulic parts like valves and pipes as well as chemical lines. Around 80 percent of all breakdowns in fluid transfer systems are due to contamination of the fluids. The most important components in a fluid system is therefore the fluid itself. The consequences of failure are critical: failure of components like valves and blockage of return lines or umbilical interrupt production, which causing huge costs for the subsea industry. OTC names several sources of dirt:

- Wax, containing many particles
- Particles from the umbilical
- Microbiological growth
- Non-filtrated fluid
- Particles from handling

In figure 2.7 the picture to the left shows a brand new pipe that is very clean. The picture to the right, on the other hand, show how microbiological dirt can grow in a pipeline over time when no cleaning has been performed.

There exist several methods that can reduce the chance of blockage, for example pigging and filtration. However, most of them are not sufficient, especially when it comes to pipelines of small diameter that go over longer distances. A company named "Ocean

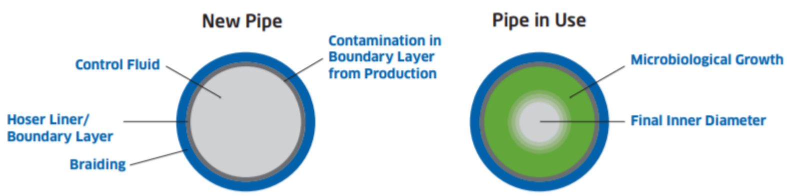

Figure 2.7: Contaminated pipes (Ocean Team Scandinavia as, 2018)

Team Scandinavia as" has therefore developed a new revolutionary technology to clean pipelines. This technique is based on using supercritical carbon dioxide ($SCCO_2$), which is not a solid, liquid or gas, but a middle thing called the supercritical state. In order to transform the liquid into this state the temperature and the pressure must exceed a specific temperature. For CO_2, the temperature must be above 31,1 degree celcius, whereas the pressure must be above 73,8 bar. An illustration of this can be seen in Figure 2.8. It can be used to clean pipes over a distance of 38 km and inner diameter of half an inch.

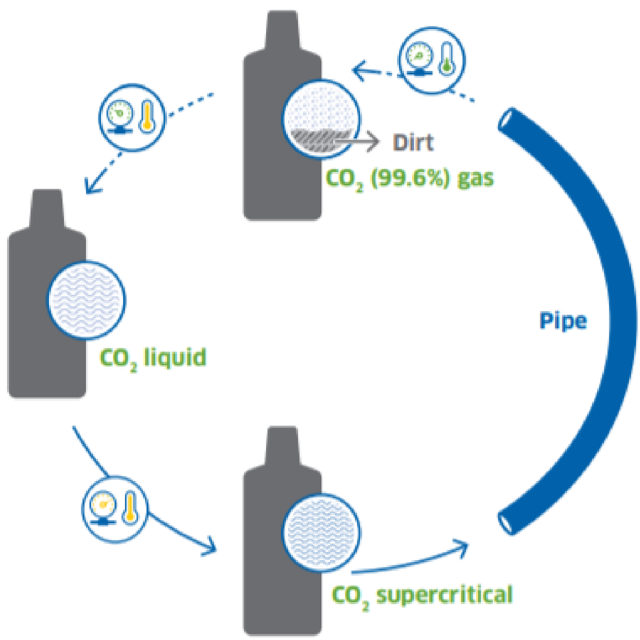

Figure 2.8: A closed loop (Ocean Team Scandinavia as, 2018)

2.7 Transport Parameters

This section will present theory from fluid mechanics which will be used later in the report for calculations relating to dimensioning of the system.

Hydrostatic pressure is the pressure caused by the weight of fluids pushing down due to gravity, and is given as:

$$p = \rho g h \tag{2.1}$$

Where ρ is the density of fluid, g is the gravity constant and h is the height of the fluid column. When calculating pressure loss of flow in a pipe, this equals the change in pressure due to the height difference.

Bernoulli's principle states that for an incompressible fluid, the increase in velocity is proportional to a decrease in pressure or a decrease in potential energy. In equation form, this is expressed as:

$$\frac{v^2}{2} + gz + \frac{p}{\rho} = constant \tag{2.2}$$

Here, v is the mean flow velocity of the fluid and z is the elevation. This principle can be used to find pressure loss along a pipe due to the total head being equal at all points when accounted for losses due to friction and minor losses:

$$gz_0 + \frac{v_0^2}{2} + \frac{p_0}{\rho} = gz_1 + \frac{v_1^2}{2} + \frac{p_1}{\rho} + \Delta p_{friction} + \Delta p_{minorlosses} \tag{2.3}$$

The pressure loss in cylindrical pipe due to friction may be calculated using the Darcy-Weisbach equation:

$$\frac{\Delta p}{L} = f_d \left(\frac{\rho}{2}\right)\left(\frac{v^2}{D}\right) \tag{2.4}$$

Here, f_d is the Darcy friction factor, v is the average fluid velocity which is usually used as volumetric flow rate divided by the wetted area of the pipe, and D is the diameter. This gives us the pressure loss per unit length (L).

The Darcy friction factor is calculated using Reynolds number. Reynolds number is a dimensionless number introduced by George Stokes to classify the flow properties and is given as:

$$Re = \frac{\rho U h}{\mu} \tag{2.5}$$

Here, ρ is density, U is velocity, μ is viscosity, and h is the relevant linear dimension. For a pipe, the relevant linear dimension is the diameter, and it is customary to use d. For a flow with a Reynolds number below 2000, the flow is considered to be laminar. A Reynolds number between 2000 and 4000 is considered unsteady, and at values above 4000 the flow is considered turbulent. For laminar flow, the Darcy friction factor may be approximated as:

$$f_d = \frac{64}{Re} \tag{2.6}$$

Equation 2.6 shows that the friction factor for a laminar flow is only dependent on the Reynolds number, and will therefore not be affected by the roughness of the surface inside the pipe (Çengel and Cimbala, 2006).

Combining Bernoulli's principle and the Darcy-Weisbach equation, we get:

$$gz_0 + \frac{v_0^2}{2} + \frac{p_0}{\rho} = gz_1 + \frac{v_1^2}{2} + \frac{p_1}{\rho} + f_d\left(\frac{\rho}{2}\right)\left(\frac{v^2}{D}\right)L \tag{2.7}$$

Minor losses are pressure losses due to bends, valves and other irregularities in the pipes. The pressure difference due to minor losses is usually small and is most commonly neglected.

2.7.1 Pump Characteristics

A pump is needed to push the chemicals down the transport line. In this, section different types of pumps, and how they work is presented.

A pump is a mechanical device that adds energy to a fluid so it can be transported and increase the pressure in a pipeline system. When selecting a pump for an intended situation, there are different physical properties that need to be taken into consideration. The most important properties are; suction pressure, viscosity, solid content, lubricity, vapor pressure and specific gravity (Lake and Arnold, 2006).

The power of a pump is defined as a function of the torque times the rotation speed (Volk, 2014) as shown in equation 2.8:

$$P = T \times \omega = p \times Q \tag{2.8}$$

Where P stands for power, T for torque, ω is the rotational velocity, p is pressure and Q is the flow rate. Using equation 2.8 with Q as the required flow rate and p as the required differential pressure, we get the power the pump needs to put into the system. There is, however, some energy lost to friction and heat which leads to a loss of power from input to output. So the pump will use more power than it puts into the system. This is shown in equation 2.9 where η is the efficiency of the pump.

$$P_{required} = \eta P_{pump} \tag{2.9}$$

There are two broad classes of pumps: dynamic pumps, also called centrifugal pumps

(CP), and positive displacement pumps (PD). A positive displacement pump adds energy to the fluid by applying a force on a fixed volume in a confined space, using a piston, plunger or diaphragm. A centrifugal pump delivers a variable amount of liquid under specific flow conditions by using rotary blades to increase the velocity of the liquid, which produces a differential pressure. Each centrifugal pump has a specific speed and impeller diameter, fluid handled and viscosity. As the head increase, the flow rate will reduce. If the viscosity increase the friction loss will increase, hence the power (Forsthoffer, 2005).

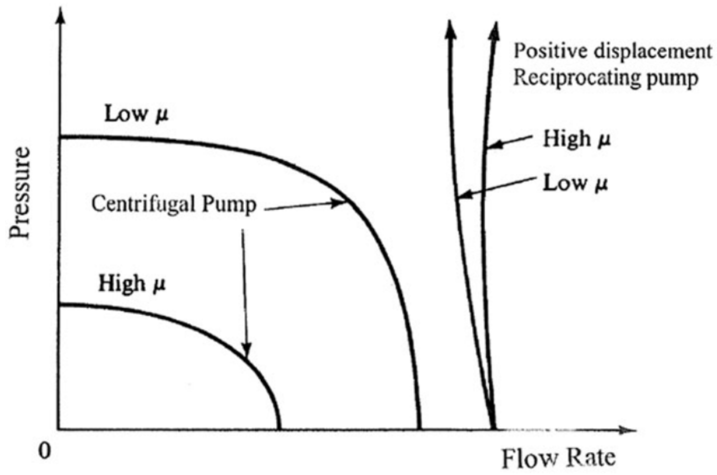

Figure 2.9: Centrifugal pump vs. Positive Displacement pump (Wu, S., 2009)

Figure 2.9 shows the differences between a centrifugal pump and a reciprocating curve positive displacement pump during operation. The PD pump gives nearly a constant flow over a wide range of pressures, while the centrifugal pump gives nearly a constant pressure over a wide range of flow rates before it drops dramatically as the flow rate decreases.

There are two types of PD pumps: reciprocating pumps and rotary pumps. The reciprocating pumps push the fluids in a closed cylinder, using a piston, plunger, or diaphragm. Rotary pumps operate in circulating motion displacing a constant amount of liquid using a rotary displacement element like gears, vanes, screws or lobes (Wahren, 2007).

When choosing a pump for a specific task, there are several parameters that need to be taken into considerations. One need to figure out if the fluid to be handled is corrosive or not, and the hydraulic conditions, like the viscosity, capacity, and head. A positive displacement pump can, for example, handle both high pressures and high viscosities better than a centrifugal pump. Regardless of which kind of PD pump used, the flow rate is not affected by specific gravity, but it is in a CP. Since production chemicals are generally injected continuously and high accuracy is required, a PD pump will be preferred over a CP for chemical injection (Forsthoffer, 2005). When choosing a pump for offshore installations it is important that it can withstand the harsh environment and the high pressures. Due to exposure to a high salinity environment, corrosion can become a threat. A high-pressure pump in a high-degrade material would therefore be preferable.

2.7.2 Pipelines

Traditionally, the term flowline is used for lines carrying unprocessed production fluids and pipeline is a transport line for processed hydrocarbons. In this report, these terms are used interchangeably to mean a pipe carrying a fluid. This project will consider transporting injection chemicals through pipelines, and this section will provide some information on pipelines used in the oil and gas industry.

Some examples of types of pipelines are; flowlines used to transfer product between platforms and subsea equipment, flowlines used for water injection or chemical injection, or multibore pipelines bundles. There are several types of pipelines currently in use, where the most common are rigid-, flexible- and composite pipes (Bai and Bai, 2010d).

Rigid Pipeline

A rigid pipeline is the most common type used in the oil and gas industry due to the low cost of manufacturing, good mechanical properties and their ease of fabrication. They are usually made out of carbon steel or manganese, and typically rigid pipelines can be single steel pipes, pipe-in-pipe, and sandwich pipeline. Depending on the intended use, the pipeline needs to have a right balance between strength, ductility, weldability, and toughness (Subramanian, 2013).

Flexible Pipeline

Flexible pipelines are constructed from concentric layers of metals and polymeric thermoplastic materials (Palmer and King, 2008). The metals provide strength while the polymers are used as sealing components, providing fluid integrity. There are generally two types of flexible pipes in use; bonded and unbonded. In bonded pipelines, the layers of steel, elastomer, and polymers are bonded together through a vulcanization process. They are used for short sections. For the unbonded pipelines, the layers of materials are separate allowing layers to move under external and internal loads. These pipes can be used for long stretches of several hundreds meters (Bai and Bai, 2014).

Each layer is added to provide a specific function, and the layers used depend on whether the pipe is bonded or nonbonded. Submarine pipelines are bonded (Palmer and King, 2008).

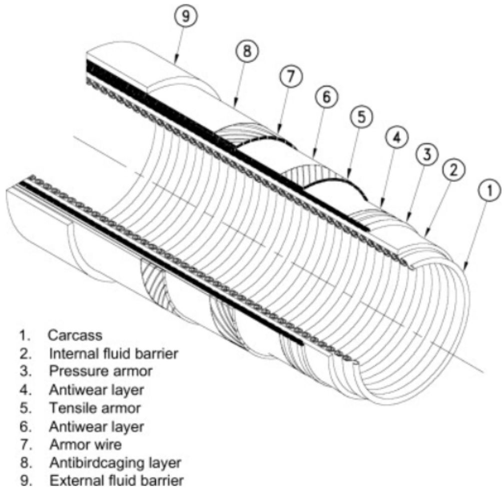

Figure 2.10: Typical cross section of an unbonded flexible pipeline (Bai and Bai, 2014)

According to Braestrup et al. (2005a) can flexible pipelines can be used in production and exportation of hydrocarbon fluids, injection of water, chemicals, and gas into the reservoir, and for service lines to wellheads. Materials used in flexible pipelines consists of; metallic material, polymeric material, epoxy resin and reinforced material.

Flexible pipelines are primarily made out of carbon steel, stainless steel, and duplex stainless steel, due to the mechanical strength, chemical resistance and erosion properties of these materials. An advantage of using a flexible pipe compared to a rigid carbon steel pipeline is that they can work under more extreme dynamic conditions, and they provide better insulation and chemical compatibility properties. They are also cheaper and faster to install, though they are more expensive than conventional pipelines (Braestrup et al., 2005a).

Composite Pipeline

Composite pipes are pipes constructed of two or more materials, for example, epoxy reinforced with fiberglass, carbon steel or silicon nitride. This method increases the strength while lowering the weight, and at the same time eliminating the risk of corrosion (Palmer and King, 2008).

Material Characteristics

Selecting the right material for a pipeline is an important step for having a successful pipeline system, and to meet with the operational requirements, throughout the intended lifetime. According to Offshore standard DNV-OS-F101 (2013), the materials for the pipeline system should be based on factors such as; the transported fluid, the loads the pipeline is subjected to, temperature, and possible failure modes during installation and operation. The compatibility between the different construction materials are also something to be aware of. Offshore standard DNV-OS-F101 (2013) also name some material characteristics that need to be taken into consideration. They are:

- Mechanical properties
- Hardness
- Fracture toughness
- Fatigue resistance
- Weldability
- Corrosion resistance

In addition, the cost of the pipeline will also be a governing factor when choosing the material.

To find the right combination of materials for a pipeline system, different standards should be viewed closely, like DNV Offshore Standard, ISO, NORSOK, and other industrial standards that contain information on how materials will react when in contact with other materials in for example a saline environment.

Internal and external corrosion can cause severe damage to the pipelines. External corrosion can be handled with cathodic protection by using sacrificial anodes, which means applying an anode (a less noble material) at the pipeline surface. Typical materials used as anodes for cathodic protection of steel would be, zinc, aluminum or magnesium. Internal corrosion can be handled by removal of water and application of corrosion inhibitor. Pigging is used for corrosion monitoring and in some cases for corrosion inhibitor application. A coating may also be used as internal protecting, but these are most often used to reduce the friction (Braestrup et al., 2005b).

At offshore installations, the material can be exposed to severe pitting corrosion, Sulphide Stress Cracking (SCC) and Hydrogen Induced Cracking (HIC) (Braestrup et al., 2005a).

2.8 Pigging

Pigging is one technique used to maintain the line efficiency as well as an aid in the control of corrosion. It involves using a device, a so called pig, also called pipeline injection gauge (Kirschstein, 2018) that is forced through the pipeline due to the differential pressure caused by the flowing fluid as illustrated in Figure 2.11. A pig comes in many different configurations, all from metal-bodied to, foam, polyurethane or inflatable (Uzu et al., 2000), and the selection of a pig depends on the type of operation that is going to be conducted (Stewart, 2016a).

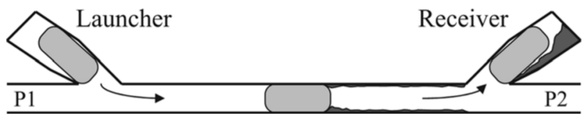

Figure 2.11: Pig driven by pressure difference across it (P1 > P2) (Quarini and Shire, 2006)

According to Quarini and Shire (2006) the four main reasons for using a pig are: "displacement/cleaning purpose, to batch/separate dissimilar products, for surveying/inspection of the line and maintenance of the line" (Quarini and Shire, 2006). Cleaning the pipeline involves removing deposits that can restrict the flow or contaminant product. These restrictions will lead to a decrease of the flow rate and an increase in the pumps energy consumption needed to maintain the same volumetric flow rate. Batching pigs are used in single pipeline where different products are going to be transported. Since two fluids will tend to mix as they flow faster in the center of the pipe than at the pipe wall, batching pigs will help separate them and prevent them from mixing. Inspection and maintenance pigs are used mostly within the hydrocarbon industry. Since some of these devices are highly complex, they may be used for different puposes throughout the whole lifetime of a pipeline (Quarini and Shire, 2006).

Besides the pig itself, a pigging system will require a pig launching-, and receiving system, and a mechanism that can track or locate the pig at all time. This will all make the potential maintenance and cleaning of the pipeline very complex. The most common way to detect a pig is to place detectors that can detect magnetic material along the pipeline. The pigs are therefore specially designed to connect with the magnetic detectors as they pass through the pipeline. To know the location of the pig is also important in controlling of the valves. In that way the valves can get a "message" when to switch to direct the fluid flow or when to catch the pig. Even though there are a lot of advantages of using a pig, there are also some disadvantages especially when it comes to the use of solid body pigs, since they can get stuck or trapped inside the pipeline. This can cause blockage of the flow, and locating, and removing it can be extremely time consuming. Most of these pigs have also limitations in regards to bends, valves, connectors and welded joints they can pass by (Quarini and Shire, 2006).

Since the main focus of this thesis is to look at gel pigs, other methods of pigging will be mentioned briefly. The most conventional form of pigging is to use a mechanical pig. They are normally formed as a spherical or cylindrical body, made out of steel, and they can be equipped with different tools depending on the task that they are going to perform. Plastic or rubber cups can be attached at the front or end, making a perfect seal against the inner wall of the pipe that either separate the fluids or pushes debris.

Gel pigs are quite different from the conventional pigs as they are made of highly viscous liquids. They can be used in pipeline operations during or after commissioning, and they can flow through the same pipe as any other fluids, which make them very versatile. The gel pigs can also flow through pipes with changing diameters, which many other pigs can not. As the gel pig is flowing through the pipe it tends to sweep water or other fluids within the line or separate two different fluids. Due to the differences in the chemical composition, the chemicals can be featuring a different flow profile, making either a laminar flow or a turbulent flow. As the fluids are transported, these differences can start an erosion process of the gel pig, which is the reason why the gel pig is usually very long (Quarini and Shire, 2006). Most of these gel pigs are based out of water, chemical hydrocarbon, or a combination of these two. The water based one is biodegradable and can be injected directly into the sea without making any environmental impact. These gels can be divided into four groups after their purpose. They can be used as sealing and separation, for cleaning and debris pickup, as carrier, or inhibitor and pre-cast (Cordell, 2003). An advantage with the gel pigs are that they can be used for many of the same purposes as the conventional pigs, as well as they have good chemical capabilities. They will also not fail during service and they can be inserted through a 2” pipe (Uzu et al., 2000).

When cleaning the pipeline it is very unlikely for a gel pig to get trapped, even if the pipe contains a large amount of debris. This is because the gel pig does not push the debris forward, the debris gets pushed within the gel. This means that a gel can clean a pipe even if it contains a big amount of debris. These gels are very good for sealing the pipe, but are not very good scourers and they are easily eroded when mixing with the fluid in the front and behind of them. They are therefore often combined with other pigs such as pig mandrel in a so called pig train. In these cases the mandrel pig will scrub the wall while the debris will get suspended in the gel. The gel pigs should therefore according to Quarini and Shire (2006) be very long, around 120 meter to maintain a good flow regime (Quarini and Shire, 2006). Uzu et al. (2000) says as well that the pig should be long, all from 100 to 500 meter depending on the diameter of the pipeline and the distances it is going to travel.

2.9 Pig Signallers, Locators and Tracking Systems

When pigging pipelines, it is important to know when the pig has left the launching trap (station) and when it has arrived at the receiver (station). It would also be of interest to know where the pig is located during pigging operation, so if anything goes wrong, the pig can be located faster to save time (Stewart, 2016b).

Pig signalers

Any pipeline that is going to be pigged should be adapted with a pig signaler at different stages of the pipeline to indicate when the pig has reached a certain point. The pipeline should also be installed both at the launcher and at the receiver to confirm when the pig has started and finished pigging of the pipeline. This will help to signalize when valves are going to be actuated during the launch and receiver procedures. These pigs can either be intrusive or non-intrusive.

Intrusive pig signalers are mounted permanently outside the pipe, and are actuated when the pig trigger a mechanism inside the pipe causing a shaft to turn giving either a visual indication, and/or an electrical signal.

Nonintrusive pig signallers are extensively used for subsea installation and do not require any physical contact with the pig, meaning they can either be mounted on, or near the pipeline. As they are mounted externally a signal will emit and trigger the pig, emitted/generated either be a magnetic field, radio transmitters and radioactive isotopes. Most systems will require a magnet to be installed inside the pig, so by utilizing a magnetometer a change in the magnetic field can be detected as the pig pass by. Another way would be to install a radioactive source and radiation detector outside the pipeline that sense a density change as a pig passes by. An advantage of using these signalers are that they can be installed on an operating pipeline without any requirement of welding and penetration. They are also portable which mean that they can be moved from one place to another when needed (Stewart, 2016b).

Pig Tracking and Locating

Pig tracking and locating are basically two different procedures. When tracking a pig, it means to follow the path of the pig. This can either be done continuously, or more likely at series of predetermined points. This is accomplished through mass balance via computer calculations, transmitter/receiver systems and acoustics.

According to Stewart (2016b) the four most commonly devices used for locating and tracking pigs are:

- Transmitters (used mainly on land lines)
- Pingers (used on subsea lines)
- Acoustic Transponders (used on subsea lines)

- Radioisotopes (used in both land and subsea situations)

Transmitter: Transmitters are electrochemical systems that transmit information from a medium to a receiver by radio waves.

Pingers: Pingers have for many years been used within the marine industry as subsea markers. The liquid inside the pipeline works as the carrier from the pinger to the pipe wall which again go to the pipe wall on the outside. A "ping" will be emitted at regular intervals an intercepted by a receiver located on a boat or a ship nearby.

Acoustic transponders: An acoustic transponder is a device used for underwater navigation, which operates by sending out a set of frequencies to a vessel after receiving a recognized interrogation pulse. These transponders are normally mounted on the pig, and each of them releases a unique signal which make it easier to locate the pig. In general, a pig that is moving at a high velocity will require a high frequency in order to ensure that the pig is detected as it passes a detection unit. Each transponder have a unique reply frequency, which enable them to collect information from several pigs at the same time. This make them perfect when tracking a pig train in long subsea pipelines (Stewart, 2016b)

Radioisotropes: Tracking the pig with the use of radioisotopes, involves before launching, placing a small radioactive source on the pig. As the pig is moving along the pipeline sensitive radioactive detectors placed on the outside of the pipeline will track and locate the pig. Radioisotopes are suitable for gas and liquid lines, and they are very unaffected by most external loads. Since the radioactive source is small, they can track pigs in pipelines of very small diameters. This is a technique that is very good to detect leaks in subsea pipelines (Stewart, 2016b). Radioisotopes send out different radiation: alpha particles, beta particles, gamma rays and neutrons, and type of radiation depends on the isotopes. Since the alpha-, and beta particles can penetrate through short distances they are not suitable for use in industrial application. Gamma-scanning is a non-intrusive technology very suitable for industrial applications, and have been successfully applied to determine changes of the density within the pipeline. The gamma ray works by absorbing the surrounding materials (von Olearius, 2009).

For many years pipeline inspection gauges (pig) have been used to perform various maintenance work in oil and gas pipelines. Parameters of different characteristics can be inspected during the pigs journey through the pipeline. Despite pigs using many sensors to detect many of these parameters, matching the data with the corresponding location has been seen as a very important factor (Sahli and El-Sheimy, 2016).

2.9.1 Particle Image Velocimetry (PIV)

Particle Image Velocimetry is a non-intrusive flow technique used for diagnostic investigations of a complex flow field. It illuminates a particle-seeded flow using a laser sheet mapping several of the images of particles as they flow through the flow. By tracking the movement of the particles, the laser can by illuminating them find the accurate velocity at any point in the flow. This technique is also frequently used to study both laminar and turbulent flows (Petrosky et al., 2015). The PIV system consists of PIV camera, a double headed laser unit and a programmable timing unit, which are used to monitor the timing of the camera and lasers (El-Gendy et al., 2011). A frequently seed particle used for PIV measurement is Polystyrene Latex (PSL) microspheres. These have the advantage that they perfectly follow the flow, due to their small size and low density. In addition their high index of refraction will also make them more visible on images (Petrosky et al., 2015).

Particle Dynamics and Particle Response Time

Choosing the right tracer particles for PIV is of importance as the accuracy of the velocity depends on the particles ability to follow the motion of the flow. It is therefore necessary to find the right particle size (size/diameter, density). Should one reduce the particle size to improve the flow tracking or increase it to improve the light scattering (Melling, 1997). By choosing the proper types of particles it can help improve the overall image conditions and mitigate experimental challenges (low laser energy density and high background noise) (Smith and Neal, 2016)

Since PIV depends on the particles to follow the motion of the flow, assuming the flow to be "naturally bouyant" is determinant for using PIV. This implies that difference between the density of the particle ρ_p, and the density of the fluid ρ_f are as minimal as possible. Stokes' drag law consider that the gravitational force Ug of a particle with a diameter dp will increase due to the applied acceleration (in this case given by the gravity g). This assumes a viscous fluid containing spherical particles, which is characterized by dynamic viscosity μ_f at low Reynolds number. This can be expressed using Stokes' theorem.

$$U_g = \frac{d_p^2(\rho_p - \rho_f)}{18\mu_f} g \tag{2.10}$$

To use Stokes theorem, it requires that the density of the particle is approximately equal to the density of the surrounding. Since the density of the particle will be slightly different from the surrounding, choosing a smaller diameter could be an optimal choice for the particle to follow the flow. On the other hand, the diameter should not be too small (in the case of Mie scattering), as small particle weakens the image intensity.

How well the particles follow the flow, can be characterized by the slip velocity, which is defined as the difference between the velocity of the particles and the velocity of the surrounding.

$$U_s = U_{sp} - Uf = \frac{d_p^2(\rho_p - \rho_f)}{18\mu_f} g \frac{du_p}{dt} \tag{2.11}$$

How well the particles are flowing, can be quantified by the relaxation time, which is defined as how fast the particle may change its fluid velocity.

$$\tau_p = \frac{d_p^2(\rho_p - \rho_f)}{18\mu_f} g \tag{2.12}$$

Smaller relaxation time means that the particle is more reliable in following the flow. The turbulent flow is commonly identified as having strong velocity gradient and regions of shear. The choice of particles seen in relation to the Stokes number, which is given by the relaxation time and the characteristic timescale of the flow.

$$S_k = \frac{\tau_p}{\tau_{flow}} \tag{2.13}$$

Smith and Neal (2016) name three different tracer particles used for PIV seeding: mie-scattering, solid, and fluorescent (Smith and Neal, 2016). The selection of particles depends on its ability to flow the flow, and intensity of the light scattered (Ibarra et al., 2017)

Fluorescent Particles

By using fluorescent particles one will be able to shift the wavelength of the incident light to a higher wavelength. This make them perfect for flows where there is a high amount of scattered light from solid surface i.e near the wall of the pipe. By combining the fluorescent particles with a camera implemented with a optical filter, it will be possible to prevent dispersed light under a specific wavelength. The particles are available as aqueous suspension, or as dry, but these are normally only available at larger diameters $d_p > 7\mu_m$.

Material	Type	ρ_p (kg/m^3)	d_p (μm)	Reference
Hollow glass spheres	Solid	1005	10	Raffel et al. (2007)
Polyamide	Solid	1003	20–100	Adrian and Westerweel (2011)
PMMA	Solid	1190	1–100	Adrian and Westerweel (2011)

Figure 2.12: Summary of Commonly Used Particles for PIV in Liquids (Smith and Neal, 2016)

2.9.2 PIG Position Estimation Using Inertial Measurement Unit, Odometer, and a Set of Reference Stations

To improve the accuracy of the PIG localization it is important to have a good understanding of the frictional force between the PIG and the pipeline.

When a failure occurs, or an inspection needs to be done it is important to know the exact location of the points of interest so the correct action can get started as quickly as possible. The problem with trying to locate PIGs in many of these pipelines are that many of them are made of thick metallic walls, which makes it impossible to obtain the position by using GPS receivers. It is therefore necessary to find other methods. Abdel-Hafez and Chowshury (2016) mention a technique that involves using inertial measurement unit (IMU), a speedometer and a set of reference stations. By finding the initial position at where the PIG is injected into the pipeline, the IMU are used to obtain the trajectory of the pipeline, and it uses the acceleration and angular rates to propagate the position and the angular orientation of the PIG. The downside is that the propagated position will very quickly drift away from the true position due to the inherent bias and high magnitude noise associated with the IMU measurement. These errors can be solved by using the position and velocity measurement from the GPS (Abdel-Hafez and Chowshury, 2016).

To get a more precise system for a seaborn application, the installation of remotely operated vehicles (ROVs) and unmanned underwater vehicles (UVVs) would be a solution. These vehicles can go deep into the water where GPS signals are not available, and where accurate navigation is critical. To solve this it has been proposed to fuse the data from the INS and precision low-noise DSVL system with a sophisticated 32-state Kalman filter algorithm. This navigation is performed by using GPS for surface alignment and DSVL for underwater velocity reference. This has resulted in a system that can be used to navigate for over 24 hours, and at sea depths below 5000 meters.

Another method for obtaining an accurate position of the PIG as Abdel-Hafez and Chowshury (2016) points out, is to construct a pipeline plan by using the information about the distance and the slope angles of the pipeline. This was achieved with the use of four odometers placed perpendicular along the pipeline. For data correction, reference stations where placed every five to six kilometres along the pipeline. So when the PIG pass by a reference station it sends the GPS latitude and longitude of the station.

Abdel-Hafez and Chowshury (2016) also present an autonomous system that determines the position, curvature, ovality, deformation, and orientation of operating operational pipelines. It uses sensors to determine the position and orientation as well as a strapdown INS. The downside by using the INS is that they are only accurate for a short period of time and needs to be updated over longer periods. The use of an odometer can therefore help measuring the direct distances traveled and what velocity it has traveled with by deriving these time-tagged distances.

2.10 Subsea Components

When working subsea we are always looking to find subsea equipment that can withstand the envirnoment it so going to be exposed to. The goal is therefore to marinize already onshore operated equipment. The second step will also be to get these devices to operate fully electrically.

2.10.1 Pump

When it comes to subsea pumps, the first step in selecting one, would be to base it on the function requirements, where and what it is going to be used for. Meaning, one needs to look at the subsea field architecture, which subsea process system is going to be implemented, and where the pump is going to be placed in the field. Another thing that need to be evaluated is what the flow rate are going to be for the entire field. The selection should also be based on the differential pressure from the field and the tie-back distance. This will depend on the type of flow that are going through the pipeline, if it is single phase or multiphase flow. Evaluation of the fluid properties must also be considered to ensure the right selection of pump. Many of these considerations are often stated in codes and standards that give a broad range of system criteria (Anwar, 2017). These standards can be found in NORSOK. There exist two types of pumps: centrifugal pumps (CP) and positive displacement pump (PD). Two types of a PD pumps are piston pump and screw pump. A difference between them are that a piston pump is shear sensitive, whereas a screw pump has excellent resistant against wear.

Based on available design the subsea pump selection can be divided into broadly two categories: rotodynamic pumps and positive displacment pump (Anwar, 2017). Figure 2.13 illustrates this.

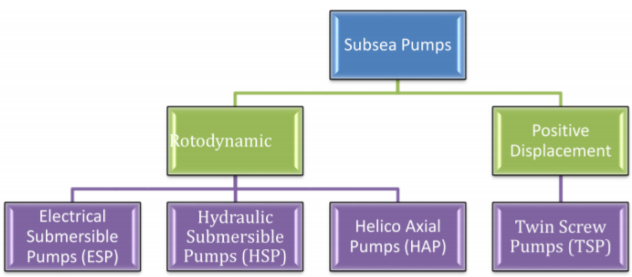

Figure 2.13: Available design (Anwar, 2017)

A helico-axial pump is a combination of a centrifugal pump and an axial compressor (Anwar, 2017). It converts speed into pressure by adding energy to the fluid as it flows through the impeller and diffusers (Carbone et al., 2013). The pump is hydraulically very flexible, and can therefore be used for many applications. It can handle a gas volume fraction (GVF) that ranges from 0 to 100, which means it can handle all from 100% liquids to 100% gas. It can also handle systems that contain sand, and a differential pressure up to 200 bar (Anwar, 2017).

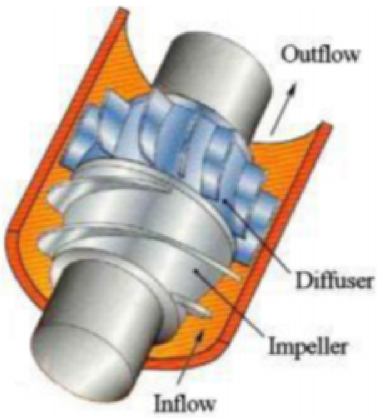

Figure 2.14: HAP bundle (Anwar, 2017)

The twin screw pump is a rotary PD pump that displaces the fluid from suction to discharge. This pump is able to handle a broad range of viscous fluids. By selecting material that can be used for wetted parts, it can also be used in systems that contain sand and other solid particles. Figure 2.15 show a cross section of a screw pump.

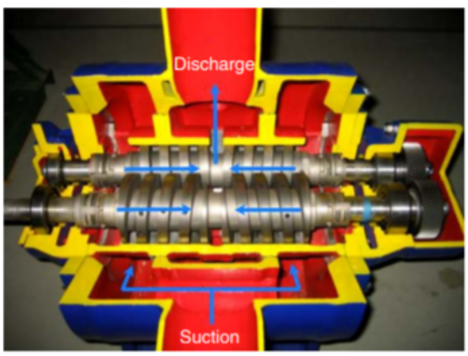

Figure 2.15: Twin screw pump cross section (Patil and Morrison, 2018)

2.10.2 Valve

Valves are mechanical devices specifically designed to direct, start, stop, mix, or regulate the flow, pressure, or temperature of a process fluid (Skousen, 1998). They can be designed to handle either gas or liquids. In subsea applications the valves will normally be placed inside the pipeline.

Within the subsea architecture there are several of chemicals valves that are in use, which can be seen from Figure B.2. One of them is the chemical injection valves (CIVs) also called chemical-injection throttle valves (CTV)

CHAPTER 3

METHOD

This chapter describes the approach used to answer the objectives of this thesis. To get a quick overview of the approach for this thesis Figure 3.1 has been sketched to illustrate stepwise how it has been conducted, from problem formulation to conclusion.

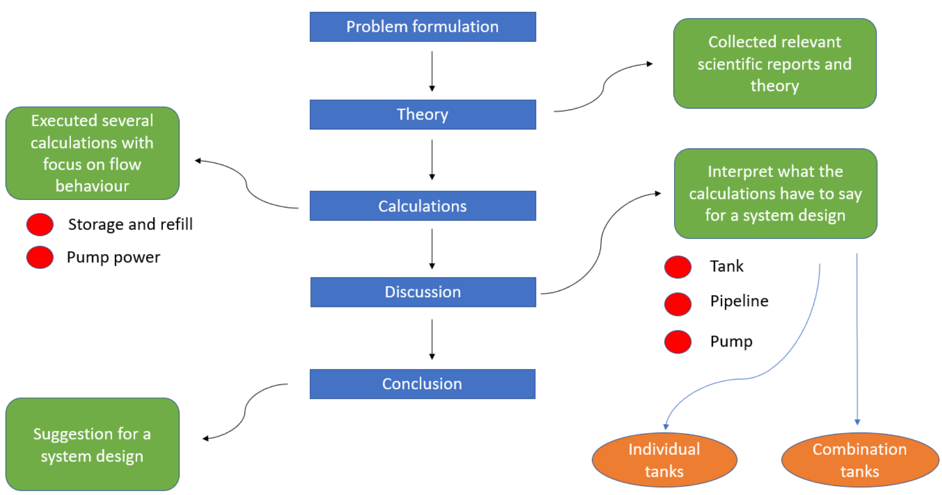

Figure 3.1: A sketch for the approach of this thesis

As Figure 3.1 indicates, the thesis started with a problem formulation in collaboration with supervisor. Scientific reports and theory relevant for this thesis is presented in the theory chapter. It has been produced by extensive search in scientific databases like OnePetro and Engineering Village. Search has also been done in Oria and Gooogle Scholar. Where articles have come to short, a deeper description has been provided by books and brochures. Then thorough calculations with focus on flow behaviour has been conducted. Results from these calculations have further been used to design a proposal to a solution for a transportation and distribution system for sending all the chemicals through one single pipeline.

Excel has been used to a large extent to make calculations for the subsea transportation and storage, with focus on flow behaviour. The calculations have been based on flow rates for one field case provided by a company named Total. Since each chemical is being separated with a liquid spacer, this needs to be taken into consideration when doing the calculations as the liquid spacer as well affects the flow behaviour. The properties used are provided by my friend and classmate Kjell H. Fjeldsaunet who has found these by conducting experiments as part of his thesis this semester.

The calculations have further been used in deciding how the chemicals can be transported and distributed through the pipeline and into different tanks subsea, with the aim to make the system as small as possible. The size dimensions for two different system have been considered; one where the chemicals are stored in individual tanks and one where they are stored as chemical combinations. To illustrate the size dimensions of a system, digital programs have been used. AutoCAD has been used to illustrate size dimensions both for a system where the chemicals are being stored in individual tanks and when the chemicals are stored as combinations. To illustrate how the chemicals could be transported and distributed Scheme Editor 6 has been used.

Due to several parameters involved when calculating on flow behaviors of such systems, there will always be some uncertainties. It will therefore be necessary to evaluate their validity. One of the uncertainties in this thesis involves the behavior of the liquid spacer. Due to the lack of knowledge on how long the liquid spacer should be so the chemicals do not mix, the liquid spacer has been considered as a parameter. The calculations have therefore taken this into consideration by calculating how the flow will behave with different lengths of the liquid spacer. The results of these calculations can therefore in the end give an indication of how the final system should look like to have a continuous operation.

CHAPTER 4 RESULTS

This chapter will contain the different storage requirements each chemical will need to operate at different time intervals. It will also illustrate how long time it takes to transport the chemicals through one single pipeline out to the subsea facility with the use of a liquid spacer of different lengths in different pipelines. To transport the chemicals all the way out to the subsea facility, they will need to be applied a pump power. A complete overview of the calculations used throughout this chapter is found in Appendix A.

4.1 Subsea Storage Requirements

Total presents in their report, requirements for a subsea chemical injection pump to operate underwater for one field case. These chemicals can be injected either continuously or batched, and based on their specification it has been suggested different pumps that could work within an oil and gas field. At the oilfield all the different production chemicals are injected with different rates, where all have different chemical properties. They have therefore come up with three different pumps. The first one is for corrosion-, scale-, asphaltene inhibitors and demulsifiers, which are being injected continuously 24 hours/day. For the second one, biocide is being injected in batches 5 hours/day, whereas the last pump is for the hydrate inhibitors, where low dosage hydrate inhibitor (LDHI) and monoethylene glycol (MEG), which are only batched on demand, meaning during start-up and shutdown. The injection rates of these are much higher, with rates of 22 l/min (0,00036 m^3/s or 31,1 m^3/h) for LDHI and 416 l/min (0,00693 $m^3)/s$, or 598,72 $m^3)/h$) for MEG. Due to the high rates for MEG injection compared to the other chemicals, it would be preferable to handle MEG separately from the other chemicals (Total rapport).

Table 4.1: Chemical Injection Rates

Chemicals	**Injection rate (l/min)**	**Injection rate (m^3/s)**
Corrosion inhibitor	0,19	3,16667E-06
Scale inhibitor	0,075	0,00000125
Demulsifier	0,07	1,16667E-06
Asphaltene inhibitor	0,17	2,83333E-06
Biocide*	3,51	0,0000585

For the gas field, the corrosion and scale inhibitors are injected continuously with the same rates as for the pump used for oil field, but with slightly different chemical properties. As for the methanol and MEG they are injected in batches on demand with the same rates and same chemical properties as for the pump suggested for the oil field.

To refill the subsea storage tanks, there are two different ways to handle it, either refilling intermittently or continuously.

4.1.1 Intermittent Refill

In this scenario, the tanks are filled up at regular intervals depending on the needs of production chemicals. The calculations are based upon the amount needed to operate for a series of time. Based on the tank module proposed by Total (Beaudonnet et al., 2012) the amount of modules needed to operate without refill after a half-year is max two for corrosion inhibitors and asphaltene inhibitor, six for biocide, and the other chemicals can stand for half a year without refill as you can see from Figure 4.1. Due to the size of the tanks and the refill duration, a reduction of tank module would be a major cost-saving solution from a design aspect.

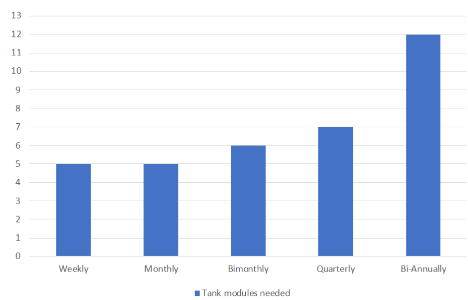

Figure 4.1: Total amount of tank that contain 30 m^3 needed to operate over different time durations

4.1.2 Continuously Refill

For a scenario where we have a continuous refill, the pump placed topside will be supplying the chemicals constantly into the buffer tanks placed subsea. The chemicals will further be pumped to their respective injection sites by subsea injection pumps.

Determining the installation these tanks should be considered thoroughly. In a case of an accident during transportation, or maintenance has to be conducted on one of the tanks, the tank should contain enough chemical for the operation to still continue without needing to shut down the production.

Based on information provided by Total, the total amount of chemicals used to operate continuously for a whole week is 12461 liter (L), which means a combined tank size of 12,46 m^3 for all the chemicals will minimum be required. The refill duration will depend on the amount needed to operate over a given time period. By injecting continuously, we can then decide the amount of each chemical that is going to be transported based on their need during operation and when to inject it. The amount should be a least enough to maintain a buffer at all time in case of an accident.

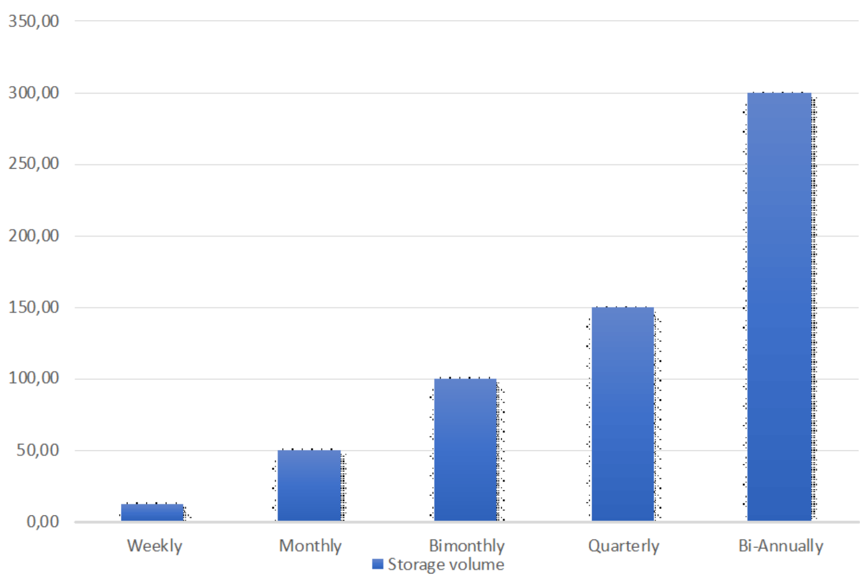

Figure 4.2: Total amount of chemicals in m^3 needed to operate for different with refill

4.1.3 Flow Calculation

All the chemicals are injected with different rates, but since the difference is very small there will be of interest to find a standard tank size that suits every chemical. Since the chemicals are going to be sent through the same pipeline, it would also be of interest to find a similar pump. Because MEG is injected with bigger rates and only injected during startup and shutdown it will not be taken into considerations in these calculations.

Storage and Refill

Based on the injection rates provided by Total (total brosjyre), biocide is the most frequently injected chemical. It will need 1,05 m^3 a day, and if we use tanks with a standard tank size of 1 m^3, biocide will need just over one of these tanks to operate on a daily basis. The rest of the chemicals can cope with just one, and this for a longer period of time without being refilled. By using a 1 m^3 tank, the corrosion inhibitor can hold for around 3,5 days, scale inhibitor for 9,25 days, demulsifier for 9,9 days, and asphaltene inhibitor 4 days.

How long time it takes before a tank has been refilled depends on the time it takes to transport the chemicals out to the subsea facility, which is dependent upon the flow rate. A factor that can have a great impact on the refill duration is the the liquid spacer. The more liquid spacer that is used the short will it take to transport the chemicals. There are no exact recommendation as to how long the liquid spacer should be, but Uzu et al. (2000) say that a gel pig can range from 100 meters to 500 meters depending on the diameter of the pipeline and the length it is going to be sent. The total amount of gel pig that is used will also be decided by the amount of chemicals the are injected at a time. Meaning injecting chemicals more frequently will require that the liquid spacer as well has to be injected more frequently. On the other hand, by sending chemicals in smaller "dosage" does not necessarily mean that the liquid spacer should be of greater length when sending them in bigger "dosage". What we can expect is that some of the chemicals will mix with the spacer, but we do not know to what extent. Some of the chemicals may also need to be separated by a longer spacer than others. This is something that needs to be further investigated. However, this is out of the scope of this thesis and will not be covered in detail. There will therefore be made assumptions of the length of the spacer.

Since the amount of chemicals are fixed, the transportation time will be dependent on the amount of liquid spacer that is used. The more used, the higher flow rate, which again will give a higher velocity. The calculations have therefore focused on pipelines with a diameter of 0,01 meter, 0,5 inch, 0,75 inch and 1 inch as bigger ones will give a very long transportation time. One liquid spacer is ranging to from 100 meter to 700 meter, where the total amount needs to operate on a daily basis that are transported is being divided into 14 "dosages" meaning a total length of the liquid spacer used is ranging from 1400 meter at the minimum to 9800 meter as maximum. A spacer fluid with a length of 140 (10 meters * 14 "dosage") is also being pointed out, just as a comparison. These differences are illustrated in Figure 4.3. What these differences have to say for the whole transportation process will be addressed later in this chapter.

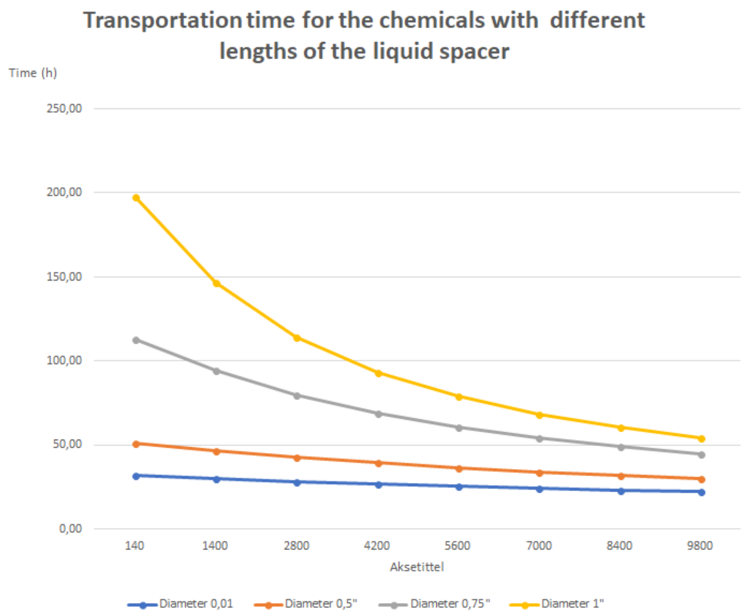

Figure 4.3: Time it takes for transporting the chemicals from ashore to subsea at different diameter

When the chemicals have arrived at the distribution station, it would be of interest to know how long time it will take to refill a tank. Figure 4.4 illustrates how long time it will take to refill a tank of 1 m^3 with the use of different pipeline diameters. By knowing this it will be easier to decide in what order and how these chemicals should be distributed in order to fill up the tanks to have a continuous operation without any disturbance. How often chemicals are being injected would clearly be based on the amount needed for operation on a daily basis, and with a buffer available in mind. The refilling duration of the tanks should, therefore, be of higher rate than chemicals injected into the production until the buffer tanks have been filled up. Thereafter we will have a steady state, where Q_{in}=Q_{out}.

Pump Power

In order for the chemicals to flow through the pipeline, the pump will need to overcome the hydrostatic pressure at the seabed and the pressure drop along the pipeline. These

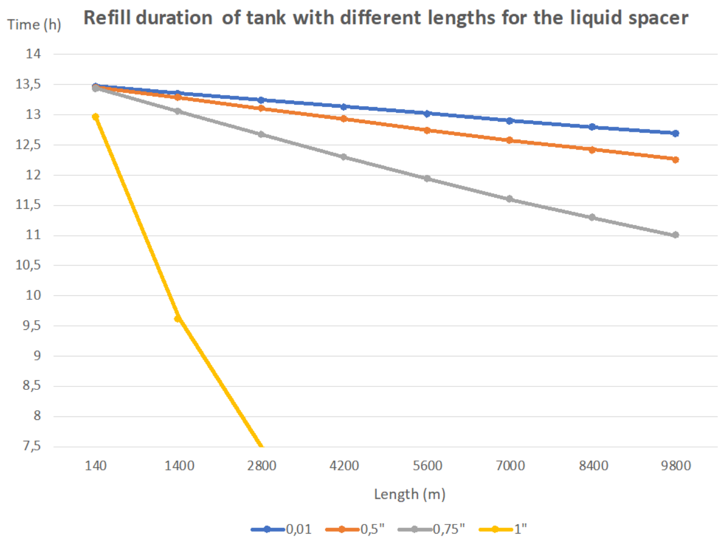

Figure 4.4: Time it takes to refill a tank of 1 m^3 with different length of liquid spacer in different pipelines

mean the pressure produced by the fluid inside the pipe, pressure on the outside of the pipe, meaning the seawater, and the pressure loss due to friction in the pipeline.

The pump power that is needed to deliver the chemicals from the onshore facility to the subsea facility is equal to the differential pressure over the pipeline multiplied by the flow rate through it 2.8. Since each chemical has different viscosities and densities, and is going to be sent through one single pipeline as a "train", the pump will need to overcome the combined power that each of all the chemical used.

The pump will, therefore, be dependent on the amount of chemicals that are going to be transported through the pipeline, as the diameter of the pipeline will affect the length of the "dosage". With a smaller diameter, the longer will the "dosage" in the pipeline be, which again affects the pressure loss due to friction. There are therefore of great interest to know the amount of each chemical that is going to be sent in one train batch, meaning the amount that is needed on a daily basis. As for the chemicals, the liquid spacer also needs to be taken into consideration as it as well creates a pressure drop due to friction.

For the liquid spacer, the values used in the calculations are values provided by my friend and classmate Kjell Håvard Fjeldsaunet, which in this semester have done experiments on finding these under different conditions. Since the liquid spacer is pseudo-plastic the viscosity changes with shear rate, and the shear rate changes with velocity and diameter. This is presented in Table 4.2 and is used in further calculations when needed.

The calculations, which can be seen in Appendix A illustrates how much power that is

Table 4.2: Chemical properties the liquid spacer at different diameters

Properties	**0,01m**	**0,5"**	**0,75"**	**1"**
Density kg/m^3	980	980	980	980
Viscosity cP	75	100	400	400

Table 4.3: Chemical properties for the different production chemicals

Chemicals	**Viscosity (cP)**	**Density (kg/m^3)**
Corrosion inhibitor	0,1	1030
Demulsifier	0,106	906
Scale inhibitor	0,102	1160
Asphaltene inhibitor	0,025	940
Biocide*	0,082	1103

needed to be applied for a daily dosage of the different chemicals to flow through different pipeline sizes. For the chemicals to be transported safely the liquid spacer need to be long enough so the chemicals do not mix. Since the amount of chemicals needed for a daily operation is fixed, there is only the amount of the spacer that may vary. Due to the difference in diameter, the length of the liquid spacer may vary depending on how it will react in contact with the respective chemicals. Therefore will more extensive research be conducted. However, transporting less amount of chemicals, but more frequently more liquid spacer will be used. Using more liquid spacer, meaning a liquid spacer of bigger length will give a very high differential pressure. However, since the spacer has been viewed as a constant length and not as a specific volume in different pipelines, the differential pressure will be of higher grad in pipelines of smaller diameters.

As mentioned earlier I have put the total length of the liquid spacer to be 140 meter, 1400 meter, 2800 meter, 4200 meter, 5600 meter, 7000 meter, 8400 meter, 9800 meter.

To get the real pump power one need to find the combined length for all the chemicals that are needed for a daily operation in a 30km long pipeline. An illustration of the power needed in different pipelines is indicated in Figure: 4.5.

In order for the pump to be able to push the fluid through the pipeline it will need to overcome a differential pressure as mentioned earlier. There is not given that a pump can be used for every pipeline in the environment it is going to be placed in. Figure 4.6 illustrates the differential pressure for a daily dosage with the use of liquid spacer of different lengths.

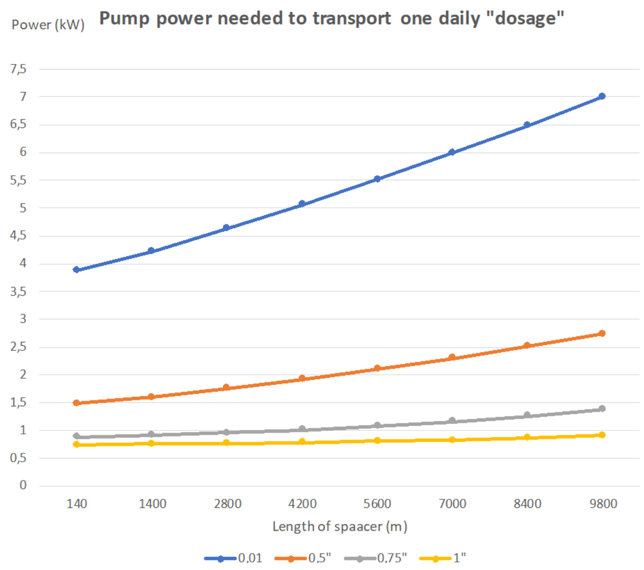

Figure 4.5: Pump power that are required with liquid spacer of different lengths

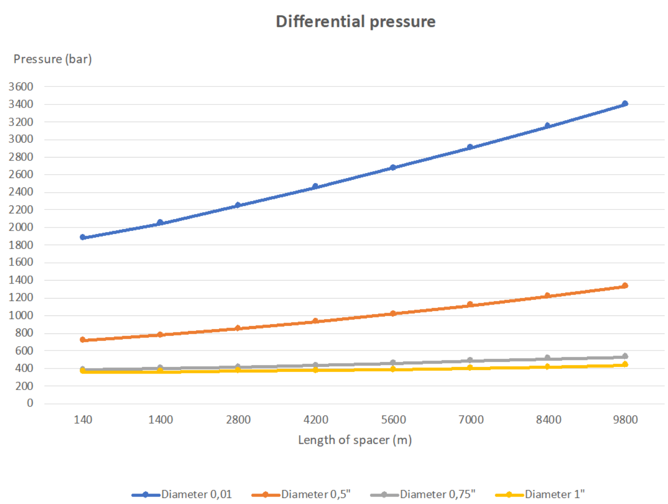

Figure 4.6: Differential pressure over the pipeline with liquid spacer of different lengths

CHAPTER 5 DISCUSSION

In this chapter I will discuss how the chemicals can be transported and distributed from the onshore to the subsea facility, based on the calculations made in Chapter 4, and the injection rates provided by Total. Further will considerations regarding the transportation and system design be looked. Continuing with the size dimensions for two different systems will be presented; one where the chemicals are stored in individual tanks and one where they are stored as chemical combinations.

5.1 Operational Strategy

The idea behind the design is to come up with a solution on how the chemicals can be sent through one single pipeline from an onshore facility to a subsea facility. From these tanks the chemicals will be further injected into their respective injection points into the well stream. Due to the uncertainties on how the chemical will behave when they get in contact with each other, each chemical will be separated by a liquid spacer. Onshore, the respective chemicals will be stored in individual tanks before they are transported, as well as a tank with the spacer fluid. Each tank has its own pump, and a supply line out of the tank. To be able to send the chemicals through the same line they need to be gathered at one point, like through a manifold. The manifold can be supported by chemical injection throttle valves (CTV) that can help regulate the flow of the chemicals. These valves are supported by an electrically operated actuator. From the manifold, the chemicals can thereafter be transported every other time, meaning first a "dose" of one chemical, continuing with a "dose" of the liquid spacer, followed by another chemical and so forth as illustrated in Figure 5.1. When the chemical "train" gets closer to the subsea facility, they can again flow through a manifold and be distributed into their respective tanks as illustrated in Figure 5.3. From the tanks stored subsea the chemicals will further be injected either continuously or batched into the respective injection point into the well.

Figure 5.1: An example on how the chemicals can be transported

5.2 System Considerations

Since biocide is injected more frequently than the other chemicals, a solution for transporting these chemicals from an onshore to a subsea facility could be to inject biocide every second time as illustrated in Figure 5.2. How much of each chemical that is going to be transported at a time should be decided upon in relation to the amount needed to have a continuous operation. If an accident occur, there should be enough chemicals in the buffer tanks for the operation to still continue until a potential failure has been repaired. However by injecting less chemicals, but more frequently, means that the liquid spacer will need to be injected more frequently. Since the amount of the chemicals are fixed, it is the amount of liquid spacer that will have the greatest impact on the flow behaviour and the final system design. The longer the spacer is, the higher will the flow rate be, which again will give a shorter transportation- and refill time. By using the lengths for the spacer used in the calculations of this thesis, the flow will be laminar with a low velocity. On the other hand, a longer spacer will also give a high pressure loss due to friction, depending on the size of the pipeline, which again will affect the applied pump power. All these aspects need to be taken into consideration when deciding on a final system design.

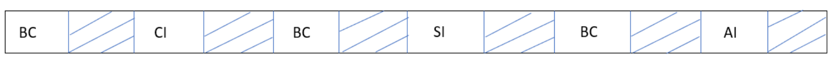

Figure 5.2: An example on how the chemicals can be transported, when biocide is injected every other time

When the chemicals arrive at the subsea facility there is another issue that needs to be addressed. What should one do with the liquid spacer? A solution could be to flush it into the sea, but due to strict environmental regulation, this might be a problem. The risk by doing this could be that some of the chemicals mix with the liquid spacer, which may be toxic for the environment. Another alternative that would be less harmful to the environment, would be to make a loop on the pipeline and send the the liquid back onshore. This would require installation of more pipelines and raise the cost, which would be undesirable. The easiest and most preferred way would be if it was possible to inject the liquid spacer directly into the well. Due to the uncertainties of the placement of the storage facility in relation to the well, the liquid spacer could as well be injected into a tank subsea and from there be injected in the same way as the other chemicals into the well.

Transporting chemicals over such long distances do not come without problems. One big problem is the viscosity of the fluid. Due to high pressure and temperature at the seabed, these changes may cause blockage of the pipeline (Brimmer, 2006), which again can lead to production shutdown. This count especially for asphaltene inhibitors which act as ketchup (Ocean Team Scandinavia as, 2018). According to Brimmer (2006) on can solve this problem if the suppliers are able to modify the fluid to hold a lower viscosity. As the chemicals can create thin fouling deposits inside an operational system, a decrease in operational efficiency may occur. Only thorough cleaning can reduce the contaminations, which may require maintenance at regular intervals. This can be done either by filtration, chemical or mechanical cleaning. Pigging is a common solution, but there are also a new invention on marked that is said to be much more efficient. Ocean Team Scandinavia as (OTC), which provides services worldwide has come up with a solution, where they use CO2 to clean the pipe, as was described in Chapter 2.5.

The high pressure and temperature subsea may cause deformation of the pipeline, creating small gaps inside the pipe. This can lead to chemicals getting stuck in gaps along the pipeline, which means that some of chemicals will get lost. This may also cause chemicals to mix with the other chemicals in the flow. However, the amount would most likely be rather small so it would probably not affect the chemical compositions too much.

5.3 System Design

The subsea equipment should be designed in order to function in the environment it is going to be installed in. The tanks should be pressure-balanced, as the pressure at the seabed will act as a part of the injection pressure. This provides a lower differential pressure for the subsea injection pumps that are installed (Beaudonnet et al., 2013). As well as the environment, the materials of the pipeline should be decided on dependent on the fluids that are going to be handled, and the expected lifetime of the installation. Most of the material used in the maritime environment are either stainless steel, aluminum bronze or nickel-based alloys (Anwar, 2017). The materials must be compatible in order to avoid corrosion. Some of the materials are also offering more mechanical strength and have good corrosion resistance. The most common material that can fulfill these criteria very well is stainless steel. It comes in different grades like duplex (DSS) and super duplex

(SDSS). These have good resistance against sulphide stress cracking (SSC) and stress corrosion cracking (SCC). To which extent these materials protect against corrosion industrial standards should be looked in to.

A PIG or a pipeline inspection gauge is a device used to clean, inspect, and separate different fluids in the pipelines. Since the chemicals or going to be transported through one single pipeline separated by a liquid spacer, it could be of interest of knowing where the liquid spacer are located given times, in order for knowing if it is flow through the pipeline as tended. In case of an accident it will also be easier and quicker to detect it, which in the end can save time and money. A method to track the liquid spacer could be to implement seeded particles in the liquid spacer. Particle Image Velocimetry is a non-intrusive flow technique that can be used to track the movement of a particle by mapping several of images as they flow through the flow. They find a very accurate velocity a any point in the flow. By installing a such device along the pipeline one would be able to see if the velocity is changing. If so, then you have may have some problem.

A pig signaler could also be of interest installing has the can emit a signal when a objective has past by. This can be very helpful when signaling to a valve when to open or close. For subsea installations are non-intrusive pig signallers extensively used. Using a radioactive source and installing a radiation detector, a density change may be detected as the pig pass by.

There are a lot of vendors that offer different pumps for different purposes. When choosing a pump one has to consider different conditions like, flow rate, viscosity, temperature and pressure the pump must handle. The pump power that needs to be applied will differ for different pipelines with different lengths of the liquid spacer. Another important factor is that the pump needs to overcome the differential pressure, which vary for the different pipeline, as illustrated in Figure 4.6. As can be seen from Figure 4.6 can the pump power varies from 3,89 and up to 7,01 kilowatts. However, due to inefficiency in real pumps, a more powerful pump should be selected. In the case of an 7,01 kW pump, where the it is using 85 % efficiency, then would the real pump needed to be $P = 7,01kW/0.85 = 8,24kW$.

5.4 Storage and Refill

There are today some companies that try to find solutions to whether there are possible to mix different chemicals or not, making so-called chemical combos. If this is possible without the chemicals loosing their treatment properties, then a distribution system for chemical injection could be significantly simpler to operate. A company that works with these options is Nalco Company as briefly introduced in Chapter 2.3. They have elaborated a simple matrix that indicates to which extent different chemicals will mix. There is therefore of interest to see how a tank solution where the chemicals are stored as combinations versus where they are stored individually could be developed.

5.4.1 Individual Tank Solution

The individual tank solution is based on the risk that chemicals can lose their ability to work as tended if they mix. Figure 5.3 illustrates a simple sketch of the idea on how the chemical can be transported and distributed into individual tanks, as mentioned in Chapter 5.1.

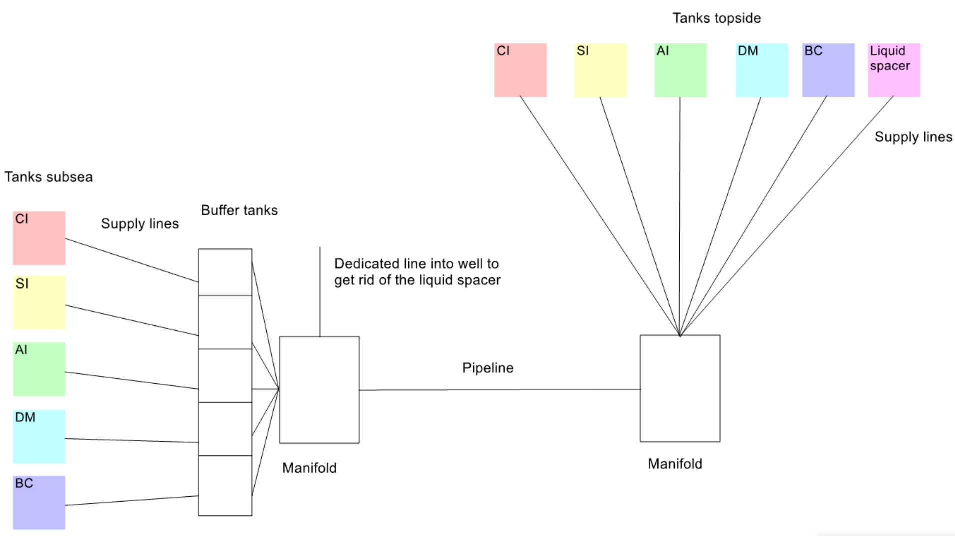

Figure 5.3: A simple sketch on the concept of the transportation from topside to subsea

Figure 5.4 illustrates how long each chemical will expand in different pipelines to be able to operate on a daily basis. Due to the flow rate and how fast these tanks are being refilled, one needs to find an optimal solution for how these chemicals should be transported in order for the operation to go continuously. As mentioned earlier, it will require a significant amount of biocide compared to the other chemicals, which mean it will have to be injected more frequently. By using a pipeline with the diameter of 0,01m, the total length will be about 23 km long. For a pipeline with a diameter of 0.5" it will be about 14 km long, 6,2 km long with a diameter of 0.75", and 3,5 km long with a diameter of 1". However, for a daily dosage one should expect it to be a little longer due to the amount of liquid spacer that is used between the chemicals. It is hard to put an exact value on the liquid spacer as it varies with the diameter and the length it is going to be transported through. There has, therefore, been made assumption of the flow behavior when the liquid spacer is of different length as described in Chapter 4. Figure 4.3 on the other hand illustrates only how long time it will take a daily amount to be transported when the liquid spacer is of different length.

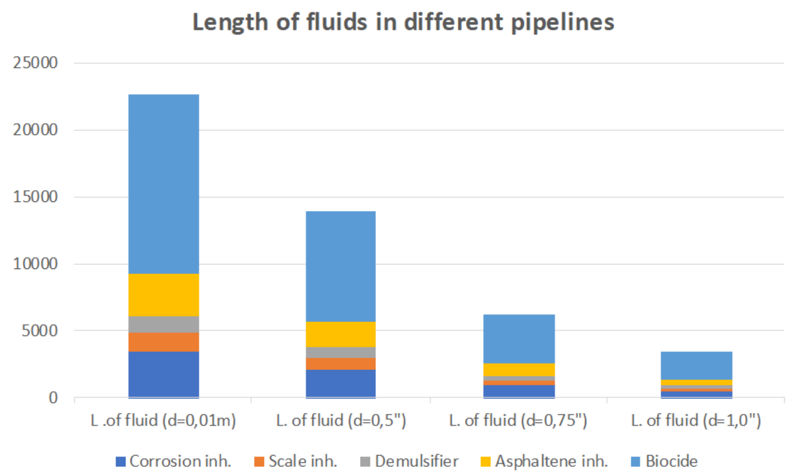

Figure 5.4: Overview of the lengths of fluids in different pipelines

Due to the wish of standardization, by designing a system where each chemical are stored in individual tanks a solution could be to install a tank module containing tanks with the same sizes. By using the injection rates provided for the field case (Total) in this thesis, a possible solution could be to use a tank size of 1 m^3. In order for maintaining the reliability and availability of the system, redundancy should be implemented. This means that if a failure should occur on one or more of the tanks or the pipeline, a buffer tank should be available for each chemical in order for the operation to still continue. The amount of chemicals stored subsea should be based on the time it takes to transport these chemicals, which again are dependent on the size of the pipeline, and the time that is expected to fix the potential failure. Meaning if it takes one day to fix the problem, there should be at least one daily amount for each chemical, plus the time it takes to transport a new "dosage" from the onshore to the subsea facility tanks. However, when something wrong happens with the pipeline, the problem will most likely be major, and the entire production would most likely shut down. On the other hand, just to get an overview on how a design would look like by taking one day of repair into consideration, a tank solution will be proposed. How the chemicals can be distributed will also be presented in form of an illustration later in this chapter.

By setting a maximum day to repair at one day, it will be needed a combined amount of buffer that can varies from 4,14 m^3 to 16,45 m^3 depending on the liquid spacer and pipeline diameter that are used. This is illustrated in Figure 5.6. With the use of a pipeline of 0,01 m, the buffer will last at a little more than two days, where for a 0,5" pipeline the buffer will just above three days. Using a 0,75" pipeline the buffer needed can range from nearly three days up to six, whereas for a 1" pipeline it can range from two and up to eight days.

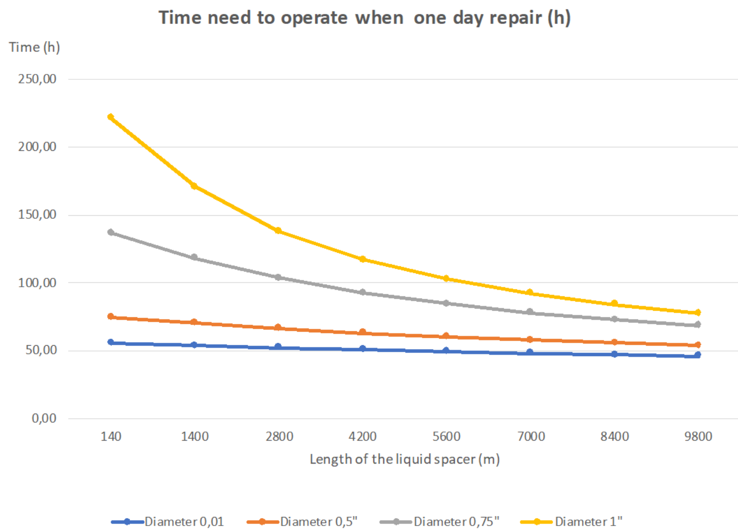

Figure 5.5: Time needed to still operate when operational failure for one day

Designing a transportation and distribution system based on a maximum reparation period of one day and using a pipeline diameter of 0,5", then biocide would need one tank for a daily operation and about four tanks as buffers. Corrosion, asphaltene, scale and demulsifier would all be needing one tank for daily operation and one tank as buffer. Each chemical should also be implemented with a tank in redundancy in case of malfunction. This will give a combined amount of tanks at 16 as illustrated in Figure 5.7. By increasing the pipeline to 0,75", the amount of buffer tanks would increase. This can however vary depending on the length of the liquid spacer.

However, due to potential failures, the availability of easy access to an error to carry out maintenance when needed is important. A more detailed design has been sketched, which can be seen in Figure 5.8.

Figure 5.8 illustrates how four of the production chemicals can be distributed after they have arrived at the manifold and into the operational tanks. From the manifold the respective chemicals will be distributed in dedicated lines through a buffer tank and further into an operational tank. In case such a tank should fail to operate, a redundancy tank should be installed in order for the operation to still continue without needing to shut down

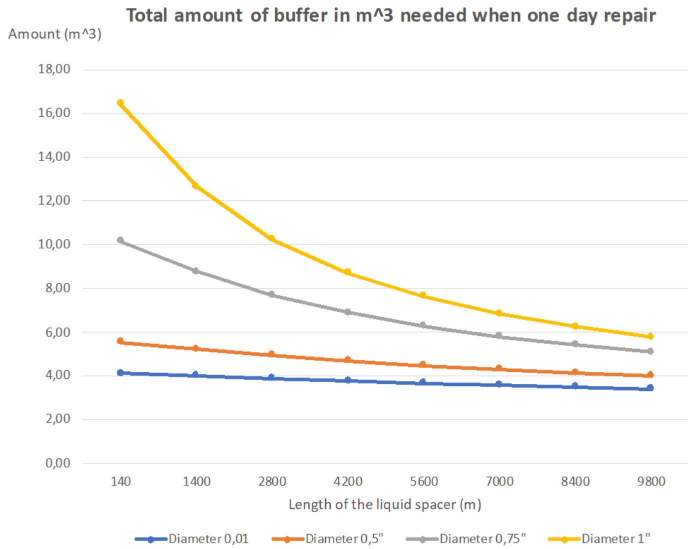

Figure 5.6: Buffer needed to still operate when operational failure for one day

the operation. After the chemicals have been injected into their respective operational tanks, they will be further be injected into their different injection points along the well.

Figure 5.9 illustrates the same concept, where the chemicals are been being separated into dedicated lines after the manifold as in Figure 5.8. However, in this design the redundancy tank has been replaced with a spare line in the case of a malfunction of the operational tank. On the other hand, this may not be a preferable solution as the there are no guarantee where the placement of the subsea station will be in relation to the wells.

5.4.2 Combination Tank Solution

By designing a system where the chemicals could be mixed and stored in the same tank, the distribution system would be much simpler, as illustrated in Figure 5.10. A safe solution would be to use the chemicals that make a green combination from the matrix provided by Nalco as these according to their test should be easy to mix. As you see from the matrix, corrosion inhibitor (CI) and scale inhibitor (SI) make a green combination, as well as asphaltene inhibitor (AI) and emulsion breaker (EB). A tank solution could therefore be to have a tank that contain the mixture of corrosion- and scale inhibitor, and another tank that contain the mixture of asphaltene inhibitor and emulsion breaker.

Since the injection rates provided by Total is based on the chemicals being injected continuously, the assumption of the chemicals making a perfect mixture need to be made. Meaning for a CI and SI mixture the Q = 0,19 l/min + 0,075 l/min = 0,265 l/min (0,0000044

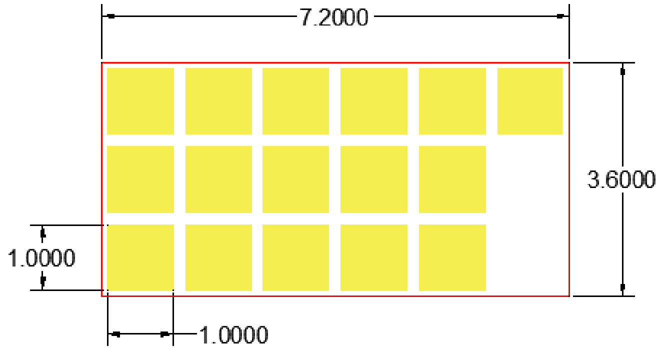

Figure 5.7: Tank module for a individual tank solution when one day break down using a pipeline of 0,5" to transport

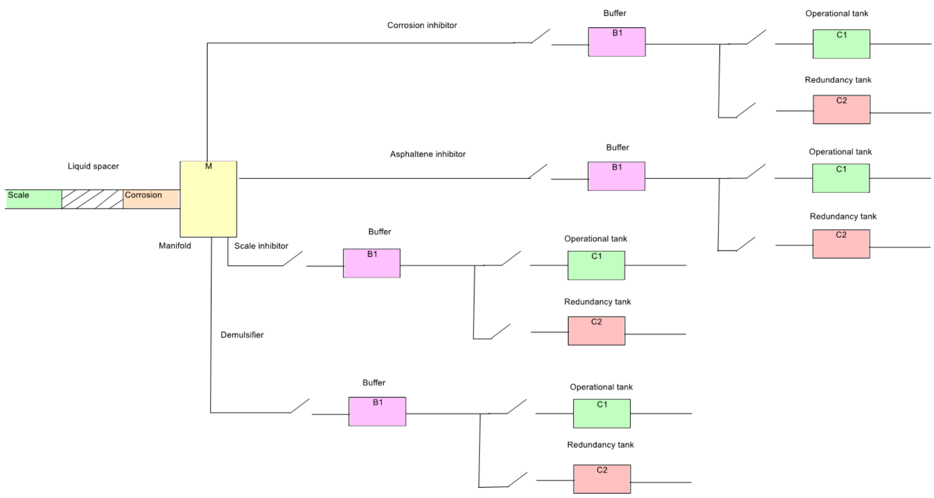

Figure 5.8: Flow diagram for distribution of four of the different production chemicals with redundancy

m^3/s), where as for a AI and EB mixture the Q = 0,07 l/min + 0,17 l/min = 0,24 l/min (0,000004 m^3/s). Since biocide is injected in batches 5 hours/day it could be of interest to have it in an own tank. With a tank size of 1 m^3, it will take 2,6 days to empty a tank of CI + SI combo, whereas for a AI + EB it will take 2,9 days to empty a 1 m^3. It will still take right under one day to empty a 1 m^3 for biocide.

Compared to a solution where the chemicals are being stored topside in separate tanks, the amount of tanks stored as combination have been reduced from six tanks down to four,

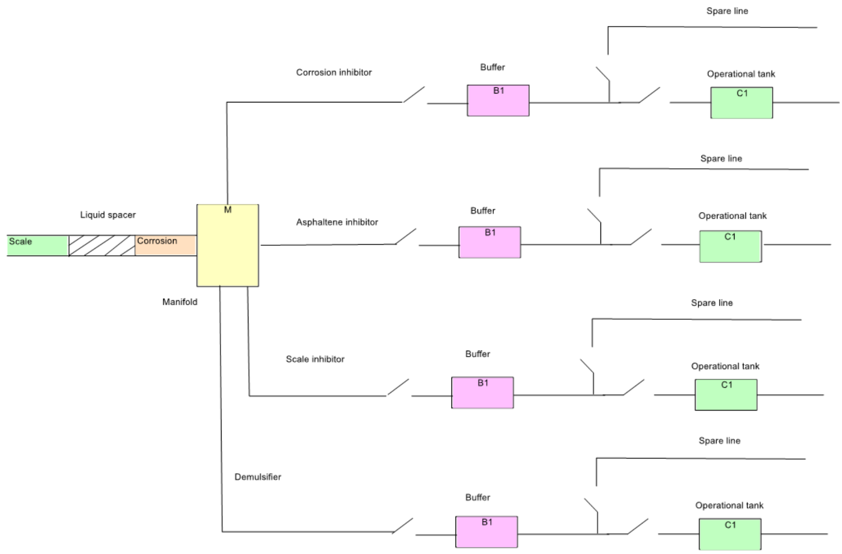

Figure 5.9: Flow diagram for distribution of two different chemicals with spare lines

including a tank for the liquid spacer. For the subsea station has the tank module has also been reduced by six tanks, for the same scenario as in Figure 5.7.

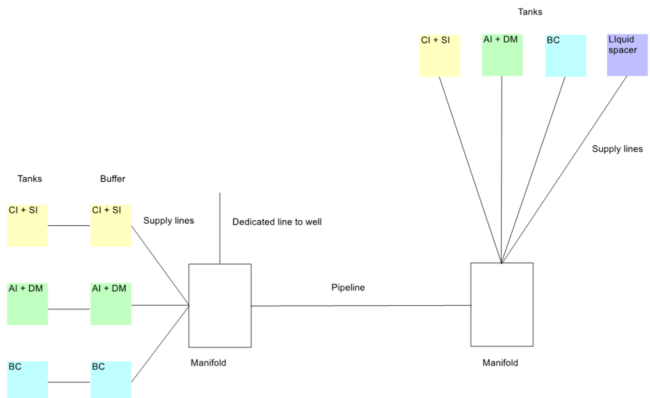

Figure 5.10: A simple sketch on the concept of the transportation from topside to subsea sent as chemical combinations

For the operation to continue as normal, the chemicals will need to be injected either continuously or in batches into the process without any disturbance. Since the chemicals are injected at specific point into the well, problems might occur when mixing some of the

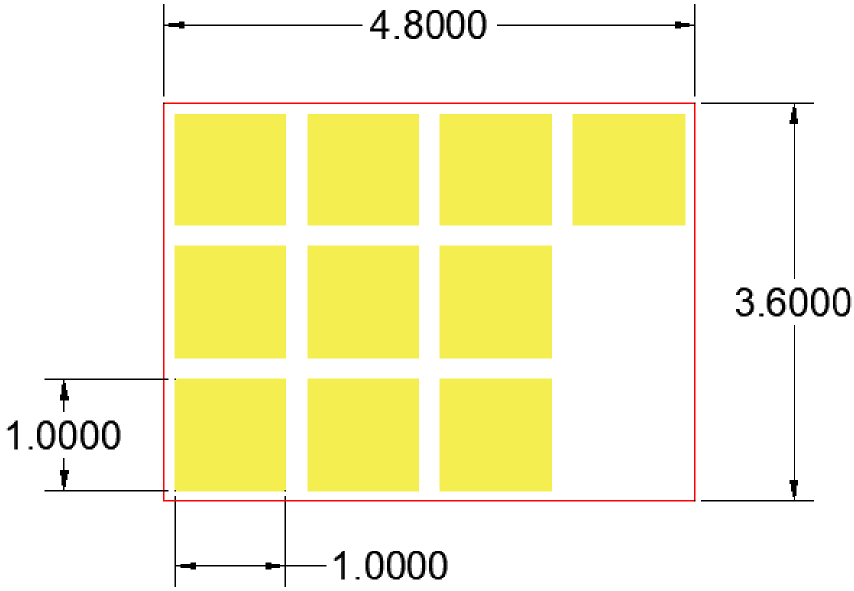

Figure 5.11: Tank module for a combination tank solution

them. As all the chemicals are injected downhole, the asphaltene inhibitor is injected into the production packer. A mixture of AI + EB may therefore be a problem, as indicated in Figure 2.5. This is something that needs to be further addressed.

5.5 Uncertainties

There are some uncertainties that needs to be addressed in this thesis:

Since there are several parameters involved in the calculations, there may occur deviations. One of them are addressed to the liquid spacer. Due to lack of knowledge on how long the spacer should be between the different chemicals, some assumptions had to be made. However, Uzu et al. (2000) mentions in their paper that a liquid spacer can range from 100 to 500 meter depending on the diameter of the pipeline and the distances it is going to travel. The liquid spacer has therefore been considered as a parameter in the calculations throughout the thesis, where calculations have been done, considering the length of the liquid spacer to be 10 meters, 100 meters, 200 meters, 300 meters, 400 meters and 500 meters. As the chemicals are going to be transported continuously over a longer distance, the total amount of liquid spacer will be considerably larger. Due to the amount of chemicals needed for a daily operation, I found it at one point reasonable to divide the daily amount of chemical into 14 portions, giving a total amount of liquid spacer being 1400 (14x100) to 9800 (14x500).

Another uncertainty could be addressed to the design of the modules and the flow diagrams. The purpose of Figure 5.7 and Figure 5.11 was to give an illustration of the total dimensions for a subsea station where the chemicals are stored in separate tanks, and where some of them are stored as chemical combinations. Due to the uncertainties of how possible maintenance could be conducted in such a module, a flow diagram was sketched. This gives an overview how a potential system could look like if each chemical were separated from the other tanks with good clearance. However, by making a little wider space between the tanks in the module as presented in the Figure 5.11 and Figure 5.7, a possible system replacement if need in a worst case scenario would be easier done.

CHAPTER 6

CONCLUSION

Due to high operational costs of oil and gas production, the industry try to find new innovative solutions that can reduce these cost, especially when it comes to cost due to flow assurance issues. The aim of this thesis has therefore been to come up with an operational strategy on how the production chemicals can be transported from an onshore facility to a subsea facility through the same pipeline.

Based on the injection rates provided by Total for one field case, it was found that biocide was injected at a much higher rate than the other production chemicals. It was, therefore, suggested that biocide should be injected every other time.

The injection rates have also been used in extensive calculations to illustrate flow behaviours due to changes in the length of the liquid spacer in different pipelines.

Nalco Champion is a chemical company that works on finding solutions to whether it is possible to mix different chemicals or not. They have developed a matrix that illustrates to what extent these different chemicals can mix. It was found that corrosion inhibitor and scale inhibitor would be relatively easy to mix, as well as for asphaltene inhibitor and emulsion breaker. As biocide was in injected in batches into the well it was preferable to keep it as a separate chemical.

By sending the chemicals as combinations rather as individuals, a tank module based on the chemicals being sent through a 0,5" pipeline was reduced from 16 tanks down to 10 tanks.

6.1 Recommendations for Future Work

As the research towards a possible SCS&I-station is at an early stage, there more areas that need to be investigated before the concept can be ready. Some of them are:

- Look at the cost of installation for a tank solution where the chemicals are stored in individual tanks versus where they are stored as chemical combinations.
- Try to find a more realistic length of liquid spacer length in order to close in on final system components.

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Appendices

APPENDIX A

TABLES

Refill frequency	CI	SI	DM	AI	BC	Sum
Weekly	1.92	0.76	0.71	1.71	7.37	12.46
Monthly	7.66	3.02	2.82	6.85	29.48	49.85
Bi-monthly	15.32	6.05	5.64	13.71	58.97	99.69
Qaurterly	22.98	9.07	8.47	20.56	88.45	149.54
Half-yearly	45.97	18.14	16.93	41.13	176.90	299.07

Table A.1: Required storage volume for different refill frequencies with chemicals in individual tanks

Refill Frequency	CI	SI	DM	AI	BC	Sum
Weekly	1	1	1	1	1	5
Monthly	1	1	1	1	1	5
Bi-monthly	1	1	1	1	2	6
Qaurterly	1	1	1	1	3	7
Half-yearly	2	1	1	2	6	12

Table A.2: Required number of tank modules for different refill frequencies with tank size of 30 m^3

Chemicals	Injection rate (l/min)	Injection rate (m^3/s)	Distance	Tank size (m^3)	Time to empty (s)	Time to empty (days)
Corrosion inhibitor	0,19	3,16667E-06	30300	1	315789,47	3,65
Scal inhibitor	0,075	0,00000125	30300	1	800000,00	9,26
Demulsifier	0,07	1,16667E-06	30300	1	857142,86	9,92
Asphaltene	0,17	2,83333E-06	30300	1	352941,18	4,08
Biocide	3,51	0,0000585	30300	1	17094,02	0,95

Table A.5: Time each chemical take to empty a tank of $1m^3$

Refill Frequency	CI	SI	DM	AI	BC	Sum
Daily	1	1	1	1	2	6
Weekly	2	1	1	2	8	14
Monthly	8	4	3	7	30	52
Bi-monthly	16	7	6	14	59	102
Qaurterly	23	10	9	21	89	152
Half-yearly	46	19	17	42	177	301

Table A.3: Required number of tank modules for different refill frequencies with tank size of 1 m^3

Refill Frequency	CI+SI	AI+DM	BC	Sum
Daily	0.38	0.35	1.05	1.78
Weekly	2.67	2.42	7.37	12.46
Monthly	10.68	9.68	29.48	49.85
Bi-monthly	21.37	19.35	58.97	99.97
Qaurterly	32.05	29.03	88.45	149.54
Half-yearly	64.11	58.06	176.90	299.07

Table A.4: Required storage volume for different refill frequencies with combo

Chemicals	Injection rate (l/min)	Injection rate (m^3/s)	Distance	Tank size, m^3	Time to empty (s)	Time to empty (days)
CI + SI	0,265	4,41667E-06	30300	1	226415,0943	2,620545073
AI + EB	0,24	0,000004	30300	1	250000	2,893518519
Biocide	3,51	0,0000585	30300	1	17094,02	0,95

Table A.6: Time each chemical take to empty a tank of 1 m^3 combo

Chemicals	Volume req. pr. day, m^3	Refill amount, m^3	L .of fluid (d=0,01m)	L. of fluid (d=0,5")	L. of fluid (d=0,75")	L. of fluid (d=1,0")
Corrosion inhibitor	0,2736	1	3483,583394	2151,347814	956,1545842	537,8369536
Scal inhibitor	0,11	1	1375,098708	849,2162425	377,4294411	212,3040606
Demulsifier	0,10	1	1283,425461	792,6018264	352,2674784	198,1504566
Asphaltene	0,2448	1	3116,890406	1924,89015	855,5067332	481,2225374
Biocide	1,053	1	13407,21241	8279,858365	3679,937051	2069,964591
Sum			**22666,21038**	**13997,9144**	**6221,295288**	**3499,478599**

Table A.7: Length of fluid if refill 1 m^3 a day

Transportation time (h)				
Length (m)	Diameter			
	0,01	0,5"	0,75"	1"
140	31,89	50,93	113,18	197,83
1400	30,22	46,76	94,47	146,95
2800	28,56	42,86	79,81	114,30
4200	27,07	39,56	69,09	93,51
5600	25,73	36,74	60,91	79,13
7000	24,51	34,29	54,46	68,57
8400	23,41	32,15	49,24	60,51
9800	22,40	30,25	44,94	54,14

Table A.8: Transportation time (hours) in different pipelines with different amount of spacer used

Refill duration (h/m^3)				
Length (m)	Diameter			
	0,01	0,5"	0,75"	1"
140	13,40	13,35	13,18	12,96
1400	12,70	12,26	11,01	9,63
2800	12,00	11,23	9,30	7,49
4200	11,37	10,37	8,05	6,13
5600	10,81	9,63	7,10	5,18
7000	10,30	8,99	6,34	4,49
8400	9,84	8,43	5,74	3,96
9800	9,41	7,93	5,24	3,55

Table A.9: Time to refill a 1 m^3tank with different length of liquid spacer

Power (kW)				
Length (m)	Diameter			
	0,01	0,5"	0,75"	1"
140	3,89	1,49	0,89	0,75
1400	4,23	1,61	0,92	0,76
2800	4,64	1,76	0,96	0,77
4200	5,07	1,93	1,02	0,79
5600	5,52	2,11	1,09	0,81
7000	6,00	2,31	1,17	0,83
8400	6,49	2,52	1,27	0,87
9800	7,01	2,75	1,38	0,91

Table A.10: Pump power that are need to be applied to push the fluids through the pipeline

Differential pressure (bar)				
Length (m)	Diameter			
	0,01	0,5"	0,75"	1"
140	1885,77	721,47	392,43	366,05
1400	2054,28	780,85	403,29	369,48
2800	2251,87	853,98	418,41	374,94
4200	2460,34	934,78	437,11	382,51
5600	2679,71	1023,38	459,71	392,52
7000	2909,86	1119,89	486,23	405,23
8400	3151,10	1224,40	517,57	420,85
9800	3403,13	1336,98	533,22	439,55

Table A.11: Differential pressure throughout the pipeline

Time need to operate with when failure based on one day repair (h)				
Length (m)	Diameter			
	0,01	0,5"	0,75"	1"
140	55,89	74,93	137,18	221,83
1400	54,22	70,76	118,47	170,95
2800	52,56	66,86	103,81	138,30
4200	51,07	63,56	93,09	117,51
5600	49,73	60,74	84,91	103,13
7000	48,51	58,29	78,46	92,57
8400	47,41	56,15	73,24	84,51
9800	46,40	54,25	68,94	78,14

Total amount of buffer in m^3 needed when one day repair				
Length (m)	Diameter			
	0,01	0,5"	0,75"	1"
140	4,14	5,56	10,17	16,45
1400	4,02	5,25	8,79	12,68
2800	3,90	4,96	7,70	10,26
4200	3,79	4,71	6,90	8,72
5600	3,69	4,50	6,30	7,65
7000	3,60	4,32	5,82	6,87
8400	3,52	4,16	5,43	6,27
9800	3,44	4,02	5,11	5,80

Table A.12: Buffer needed when operational failure for one day

APPENDIX B

FIGURES

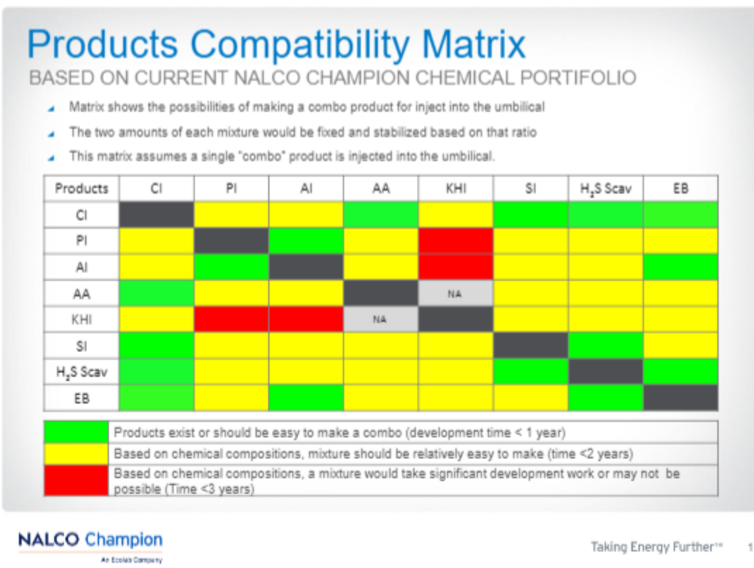

Figure B.1: Compatibility Matrix (Nalco)

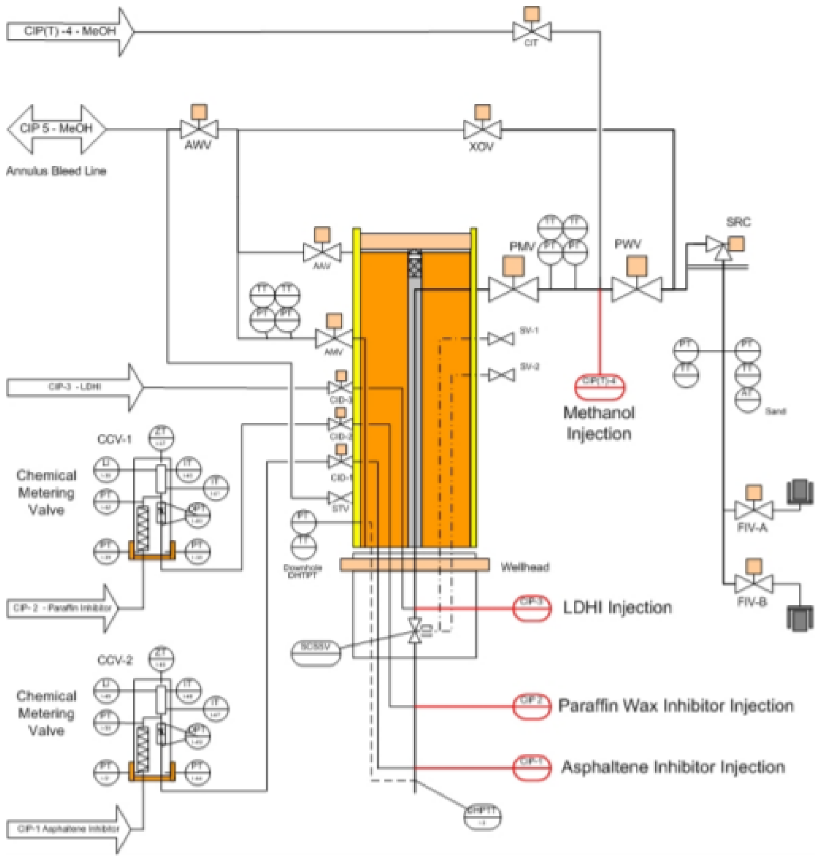

Figure B.2: Tree PI&D (Brimmer, 2006)