University of Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program/Specialization: M.Sc. Petroleum Engineering/ Drilling Engineering	Spring semester, 2016 Open
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Thesis title: **Subsea live well intervention using a riserless/open water coiled tubing system – System overview and operational weather limitations**	
Credits (ECTS): 30	
Key words: Open water coiled tubing Riserless coiled tubing Operational weather limitations Applied top tension	Pages: 164 + enclosure: 6 Stavanger, 15.06.2016

Preface

"*The paradox of learning a really new competence is this: that a student cannot at first understand what he needs to learn, can learn it only by educating himself, and can educate himself only by beginning to do what he does not yet understand.* "

- Donald A. Schőn

This thesis concludes my 5th and final year of studying Petroleum Technology at the University of Stavanger. The thesis is written for Statoil ASA, but I had the pleasure of cooperating with both Island Offshore Subsea in Stavanger and 4Subsea in Asker.

Six months ago I started this project with a lot of motivation and determination to succeed. I quickly noticed that my knowledge about well intervention, and especially coiled tubing, was limited. To learn more about the concept of Open Water Coiled Tubing, I had the privilege of cooperating with Island Offshore Subsea. They welcomed me with open arms, and helped me to the best of their ability. The start of the semester can thus be characterized as a long process of obtaining general knowledge.

In late March I started to prepare myself for the visit to 4Subsea in Asker. The goal was to improve my skills in the field of material mechanics and marine hydrodynamics to be able to handle simple terms and concepts. Similar to as when I started the project, knowledge was lacking. Several hours were spent trying to figure out the logic behind my calculations. Considering my background, after studying Petroleum Technology, several concepts were relatively unknown to me.

In mid-April, I ventured off to visit 4Subsea. A whole week was spent aiding Sveinung Eriksrud in the construction of an Open Water Coiled Tubing model in Orcaflex and learning how to navigate in the software. Words cannot express the frustration I felt sitting alone in the hotel room after spending the first days trying to make the puzzle pieces fit together. At this point, the light that was supposed to be the end of the tunnel was instead the light behind me as I entered it. However, the initial struggle was necessary. At the end of the week, with the help from Trond Pytte and

Sveinung Eriksrud, I started to get an overview. I was now ready to go home to Stavanger and work on my own.

Upon arrival in Stavanger, I had seven weeks to finish my thesis. After obtaining the initial results after two weeks, I noticed a few errors in the model. As a consequence, all simulations had to be repeated with the new adjusted model. And as if that wasn't enough, my hard disk failed two weeks prior to the deadline. Since the last safety copy was a couple of weeks old, I had to perform several simulations again for the third time to obtain the results. For this very reason, I was not able to work with the results as much as I wanted to. After all, I am very pleased to have learned so much in such a short time-span, which is the main objective with a master thesis.

Acknowledgments

First and foremost I would like to thank Statoil ASA for the opportunity to work on this interesting project.

My initial contact person in Statoil was Svein Helge Gundersen, team leader for the RLWI department. A warm welcome was given to me when I first arrived at the office in Vestre Svanholmen, Forus. I was quickly introduced to the rest of the team, and I felt honored to be surrounded by so many talented engineers. Svein Helge funded my one-week visit to 4Subsea in Asker. For this he deserves great thanks. That was a week I cannot imagine being without.

The first person I was introduced to was Jarle Østensen Aas, the youngest engineer in the RLWI department. He had written his MSc thesis one year ago, and knew what I was up against in the following period. He willingly shared his experience and advice. My thanks are hereby granted.

My contact person in Island Offshore Subsea was Vidar Haugen. Several pleasant visits at the office strengthened my understanding. He stands responsible for much of the data used in the model in Orcaflex and he supported me and my project throughout the period of which it was written. Great thanks are deserved, both for him and Island Offshore Subsea.

Trond Pytte and Sveinung Eriksrud in 4Subsea surprised me with their genuine willingness to help and support me, both during my stay and for several weeks after I returned to Stavanger. It was a challenging period for me, and their patience and understanding was greatly appreciated. Thank you!

My supervisor in Statoil, advisor and Professor Lorents Reinås deserves my outmost thanks. Numerous meetings with him fueled my motivation, and I wish to thank him for his positive attitude and support. I hope he has seen how much I have learned and hopefully developed during this period. He is an inspiration to me, and I look up to him with respect.

I would also like to thank Scott Kerr and Tore Geir Wernø in Statoil and my supervisor Professor Bernt Sigve Aadnøy at the Department of Petroleum Engineering at UiS for their contributions.

And last, but nowhere near least, I want to express my loving gratitude to my girlfriend Siri for putting up with my sometimes grumpy face. Her support, friendship and love were what encouraged me the most during hard times.

Nikolai Opsanger

Abstract

This thesis gives an introduction both to a conventional CT operation setup and to an open water coiled tubing (OWCT) system and focuses on the main differences. An overview of proposed OWCT concepts is briefly presented.

To assess operating limitations of an OWCT system consisting of several components, it is important to identify the weaker parts of the system. A specific OWCT system was modeled and analyzed using the Finite Element Analysis (FEA) software Orcaflex. Orcaflex provides system response loads which are post-processed for code check analysis. The analysis has been supported and verified by hand calculations. Based on the results from this analysis it is evident that the CT string is the weak link in this specific modeled OWCT system. This is not a general conclusion, but is a general recommendation based on the presented work. A CT string with a larger structural capacity or a subsea stack component with reduced structural capacity could change this conclusion for a different OWCT setup.

Applied top tension plays a significant role for operating limits in an OWCT system. Both excessive and inadequate tension has a negative effect on the CT string. However, no guidelines exist to properly set the value for top tension in the CT string. Based on the present work, the applied top tension during an operation should be as low as possible, but sufficient to ensure positive effective tension in the entire CT string. A general procedure for determination of applied top tension in a tensioned heave configured OWCT system has been established and is presented as a recommendation.

1. Contents

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1.4 Abbreviations

AHC	Active Heave Compensator
CT	Coiled Tubing
DPMV	Dynamically Positioned Monohull Vessel
IOSS	Island Offshore Subsea
LCF	Lower Cursor Frame
LWI	Light Well Intervention
MODU	Mobile Offshore Drilling Unit
NCS	Norwegian Continental Shelf
OWCT	Open Water Coiled Tubing
PHC	Passive Heave Compensator
RAO	Response Amplitude Operator
RICTIS	Riserless Coiled Tubing Intervention System
RLWI	Riserless Light Well Intervention
SIM	Subsea Intervention Module
SSI	Subsea Injector
TSI	Topside Injector
TTRD	Through Tubing Rotary Drilling
UKCS	United Kingdom Continental Shelf
WD	Water Depth
WL	Wireline

1.5 Terms

Subsea stack	All components present on top of the subsea wellhead and x-mas tree
Specified tension in PHC	The specified/applied tension in the passive heave compensator. The topside injector is placed on a lower cursor frame which is suspended in the passive heave compensator. Implemented to avoid confusion when referring to top tension in CT.
CT in water column	The length of the CT between the vessel and the subsea stack
Hotspot	A point/area on a structure that is subject to greater loads compared to other points/areas.
CT at entering point into SSI	The point at where the coiled tubing enters the subsea injector
100m-model	The model of the OWCT system in Orcaflex with a water depth of 100m
300m-model	The model of the OWCT system in Orcaflex with a water depth of 300m

1.6 List of symbols

A_{int}	Internal cross-section area of pipe
A_o	External cross-section area of pipe
D	Water depth + distance from MSL to TSI
D_o	Nominal outer diameter of pipe
E	Young's Modulus
F_d	Design factor
F_y	Yield tension
H_{max}	Wave height
I	Second moment of inertia
ID_{top}	Inner diameter at top of funnel
ID_{bot}	Inner diameter at bottom of funnel
L_{CT}	Length of CT between vessel and subsea stack
L_{funnel}	Length of funnel
M=M_{bm}	Bending moment
M_{dyn}	Dynamic bending moment
M_{max}	Maximum bending moment
M_{mean}	Mean bending moment
M_{pc}	Plastic bending moment capacity of pipe
M_y	Yield bending moment
P_b	Burst pressure of pipe
P_{int}	Internal pressure
P_o	External pressure
r_1	Inner radius at top of funnel
r_2	Inner radius at bottom of funnel
R_{funnel}	Radius of curvature of funnel
R_{min}	Minimum allowable radius of curvature of CT
T_e	Effective tension
t_2	Pipe wall thickness without allowances
T_{pc}	Plastic tension capacity of pipe
T_{PHC}	Specified tension in the passive heave compensator
T_W	True wall tension
u	Utilization
w	Weight per unit length of CT
$W_{CT,dry}$	Dry weight of CT
$W_{CT,wet}$	Submerged weight of CT
W_{TSI}	Dry weight of topside injector
y	Distance to neutral axis
Y	Length of subsea stack stick-up
θ	Offset angle
σ_y	Elastic yield strength
σ_u	Design ultimate yield strength
ΔX	Vessel offset
ΔZ	Set-down

2. Introduction

2.1 Background

The development of subsea technology has, ever since the world's first subsea well was brought into production in 1961, progressed forward to great heights. No less than 5000 subsea wells exist today, and the number is increasing. With the increasing number of wells comes increased need of well maintenance, i.e. well intervention. Well intervention is in general one of the cheapest ways of optimizing production in a well.

However, one of the main disadvantages with subsea wells is the high costs associated with well intervention. A platform provide the means to access a well directly. On the other hand, a subsea well requires connection between a floating vessel and the subsea x-mas tree via intervention equipment. This is a costly approach, and well interventions on subsea wells are therefore performed less frequently than on platform wells. Thus, recovery factors are lower for subsea wells – typically 10 to 30% lower – than for platform-based wells [1].

Well intervention on subsea wells is typically associated with a Mobile Offshore Drilling Unit (MODU), e.g. a semi-submersible rig or drillship, and the utilization of a workover riser system. Due to the long time it takes to position and/or anchor the rig and installing the workover riser system, this approach requires several days of operation before any effective work can be initiated. This is one of the factors that have contributed to operator interest in more cost-effective well intervention methods. The establishment of Riserless Light Well Intervention (RLWI) has, since 2005, been a factor contributing to reduced intervention costs on subsea wells. RLWI is the term used to describe the method for performing inspection and maintenance of subsea wells from a dynamically positioned monohull vessel (DPMV). This is done by lubricating a toolstring suspended in a wireline (WL) into the subsea well under full pressure, but without using a workover riser (WOR).

Figure 1 show intervention cost per well in 2011 for different installations [2]. It can be seen that the smaller and more agile DPMV has considerably lower intervention costs per well compared to a floating rig.

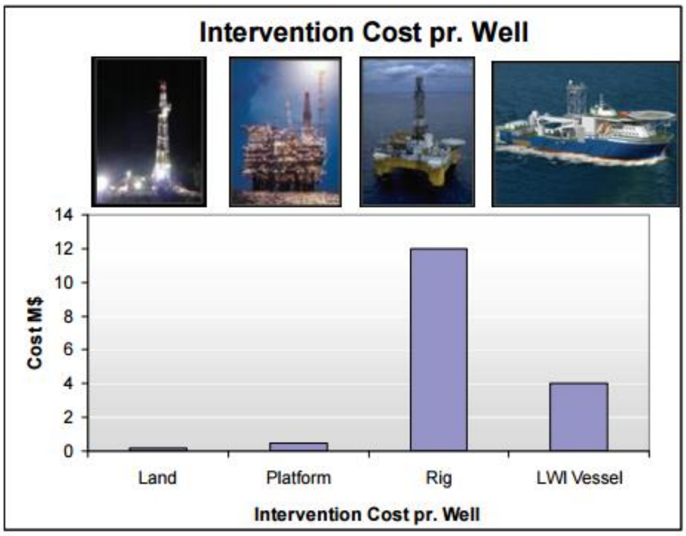


Figure 1 - Intervention Cost per Well in 2011 [2]

However, while WL is convenient for lighter operations such as production logging or running plugs, the heavier operations such as running straddles and performing perforation and stimulation jobs can be said to be more efficiently achieved with coiled tubing (CT), especially in highly inclined or horizontal wells [3]. In addition, operations such as Through Tubing Rotary Drilling (TTRD) and pumping operations requiring deep circulation points are exclusively performed by CT. Today, CT well intervention on subsea wells is performed from MODU's, and has a good track record in Statoil. It exists as a proven method without technology gaps. However, the last operation performed from a MODU in Statoil ASA was done in 2008. A historical overview of subsea CT intervention in Statoil is shown in Figure 2 below [4].

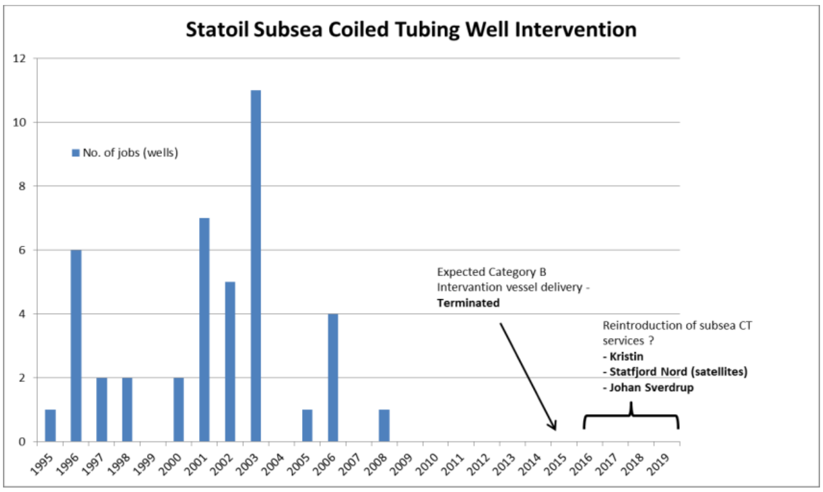


Figure 2 - Historical overview of subsea CT intervention in Statoil [4]

The absence of subsea CT operations since 2008 is believed to be partially due to the expected delivery of a Category B well intervention vessel. This vessel was specifically planned to make subsea CT operations more efficient. However, this contract was terminated in 2013, even before construction of the vessel had commenced. In addition, tractor and stroker technology development has made it possible for WL to perform many of the operations that previously required CT, and can thereof be considered as the main reason to the reduction of CT operations performed in later years.

Statoil ASA is indicating need of subsea CT intervention in the future. More specifically; Statfjord Nord, Kristin and Johan Sverdrup licenses have expressed a possible demand for CT services in the period between 2016 and 2019, and research is still on-going to estimate the need for future CT intervention on subsea wells [4].

The high rig rates and the complexity associated with performing CT with a WOR from a MODU has led to increased interest in performing riserless CT from a DPMV, or commonly called Open Water Coiled Tubing (OWCT). The concept of OWCT is still in the development stages, and an efficient contemplated subsea deployment system for entering a live well is currently not available. However, the OWCT concept is progressing. In 2014, Island Offshore Subsea's OWCT system, integrated with Baker Hughes topside equipment, drilled three wells for the Norwegian Public Road Administration (Statens Vegvesen) using riserless CT from a DPMV. The purpose was to obtain core samples to map the rock located in the tunnel trajectory (E39 Rogfast) [5]. This was considered a ground breaking operation, and caught a lot of attention in the industry. To that effect, Island Offshore performed riserless CT drilling for Centrica on the Butch field only one year later [6]. The purpose of this operation was to drill a pilot hole to search for shallow gas. These two operations has demonstrated operational feasibility for operations not in need of well control equipment and marks the first steps towards riserless coiled tubing live well intervention using a system deployed from a LWI vessel.

Developing an OWCT deployment system to enter live wells is not a new idea, and several other proposals have been made for such a system. [1] Despite the efforts, OWCT systems are still not finding their way into the market. Much of the technology remains untested on an oil well and the projects are often set aside.

[1] ABB Offshore Systems (RICTIS), GoM/Blue Ocean (Open water CT), BJ Service/Exxon mobil (SIM), Statoil/Halliburton (SWIFT) etc.

2.2 System description

A generalized OWCT system's main objective is to enter a live subsea well from a DPMV without the use of a workover riser. Figure 3 displays that similarly to a MODU, a DPMV is subject to dynamic motions behaviour. Since a DPMV is smaller in size, it is natural that the effects of the dynamic response of the vessel are amplified compared to a MODU.

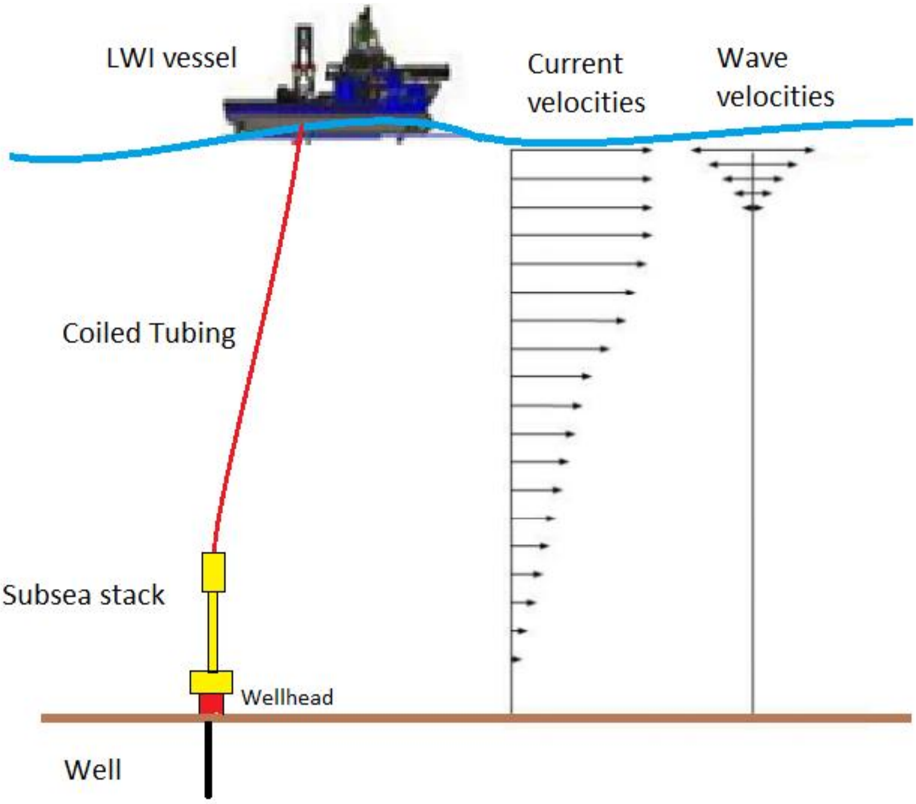


Figure 3 - System Description

Considering a DPMV that is connected to a subsea well via an OWCT system, the system will be in direct contact with the surrounding environment. The DMPV, the CT string and the subsea stack will be exposed to environmental loads, i.e. loads from waves, ocean current and wind. A DPMV uses thrusters to maintain position. The thruster forces will work against the environmental loads, resulting in dynamic motions imposed on the DPMV. The dynamic motions will transfer loads onto the OWCT system components. The operational weather limitations are thus twofold dependant;

1. The OWCT system's ability to compensate for the dynamic motions.
2. The OWCT system's structural capacities

3. Methodology

This thesis consists of two main parts. The first part aims to introduce the reader to the concept of Open water Coiled Tubing, while the other part involves analysis of a model of an OWCT system constructed in the FEA software Orcaflex. The latter part is highly focused.

Two models are created in Orcaflex 9.8b for two water depths. The models were made by Sveinung Eriksrud in 4Subsea, and are based upon Island Offshore Subsea's (IOSS) plans for an OWCT system to be applied on live wells.

The writer of this thesis was responsible for the input data, the assumptions and the boundary conditions used in the models. IOSS's plans are still under development and assumptions are made where information was lacking. It should thus be emphasized that the models are simplified. The simulations and the analysis were also performed solely by the writer of this thesis. Hand calculations were performed to verify the models/simulations. Island Constructor is chosen as the vessel and its Response Amplitude Operators (RAO's) are used in Orcaflex.

All conclusions are drawn from the results obtained from these models. Since an OWCT system has yet to be deployed on a live well, there is no way of comparing the results to empirical data obtained from a real system. The results will therefore only be correct for this specific model and the analysis method used. However, analogues could be drawn to Island Offshore's OWCT drilling operations (Butch/Rogfast) [5, 6].

3.1 Thesis definition

Deployment of a riserless/open water coiled tubing system on a live subsea well is a concept gaining increased interest in the oil industry. The OWCT concept aims to improve subsea well intervention efficiency. The concept incorporates the principles of a RLWI system together with new equipment specifically designed to perform CT operations.

OWCT performed from a DPMV vessel may be qualified as a better alternative to riser-based systems when it comes to efficiency and costs. However, a DPMV is to a much higher degree affected by environmental loads, i.e. loads imposed directly or indirectly by the ocean environment [7]. Waiting on weather (WOW) due to exceeded operational weather limitations is thus a concern. Statistics from the RLWI vessels operating for Statoil's RLWI department (Island Frontier and Island Wellserver) shows that WOW, in the period between 2010 and 2015, was responsible for 45% of the total non-productive time. This has an impact on operator revenue because it results in a reduced total number of operations being performed per year, which again delays the potential oil recovery. One step in the right direction could be to establish an estimate of the availability that a DPMV has for doing riserless CT when only considering the operational weather limitations.

3.1.1 Objectives

The purpose of this thesis is to provide results that could aid in the estimation of the availability and to provide a better understanding of what is governing the operational weather limitations in an OWCT system. The structural responses in the modelled OWCT live well intervention system are investigated in different scenarios, where focus has been given to the effect of first-order loads.

Main objective: Contribute to a better understanding of what is governing the weather limitations in an OWCT system.

- Part I: Provide a general OWCT system overview
  - Compare a conventional CT setup to a an open water CT setup
  - Briefly present different OWCT concepts
- Part II: Analysis of the OWCT models in Orcaflex
  - Determine potential system hotspots
  - Investigate the effect of the modelled funnel/bellmouth on bending moment in the CT string
  - Investigate the effect of varying applied top tension and compare for different water depths (100m and 300m).
  - Propose a procedure to determine the applied top tension.
  - Identify which effect, vessel motion or wave loads, is governing the dynamic loading and compare for different water depths (100m and 300m).
  - Investigate the effect on system loads for downstream and upstream vessel offset conditions.

After obtaining results from the model with a water depth of 100m, time was limited to analyse the model with a 300m water depth. Results obtained are characterized by this.

3.2 Limitations

The work done in this thesis is based upon the results obtained from the modelled OWCT system in Orcaflex. The model is limited to an intervention scenario were the CT is fixed between the topside injector (suspended in the heave compensation system on the vessel) and the subsea injector residing as the uppermost component of the subsea stack, i.e. it is a tensioned heave configuration. The investigated scenarios are constructed such that focus is given to the effect of isolated first-order loads.

The following accidental load condition has been particularly investigated:

1. Loss of vessel position while CT is fixed to both topside injector at surface and subsea injector in subsea end.

Two models have been constructed in Orcaflex, one for each water depth; 100m and 300m. The only difference between the models is the water depth, and hence the length of CT stretching from the vessel down to the subsea stack. The water depths are North Sea relevant. The umbilical/hose is neither modelled nor given attention.

The results obtained are case specific. This implies that different results will be obtained by varying input parameters. The results are hence only valid for the specific case. However, the discovered trends and effects can probably be extracted and applied in other scenarios.

Fatigue/cyclic loading of the CT is neither modelled nor part of the analysis, i.e. material degradation has not been considered in any load estimates. However, from literature there is evidence that CT fatigue need to be further addressed. See section 5.5.

Well barrier philosophy in OWCT system is a huge topic on its own, and will not be addressed in this thesis.

The modelled subsea stack stick-up, including the wellhead, is 46,096m. The CT outer diameter is 2 7/8” with associated wall thickness 0,188”. Other CT dimensions can be used for OWCT applications.

Both static and dynamic simulations are performed. Simulations with offset without introducing environmental loads (waves and current) are performed using a quasi-static approach, i.e. the vessel moves slowly enough for the system to be in equilibrium. Simulations with waves will have a wave height of 7m (Airy), with wave periods ranging from 6s to 18s. Regular waves are used in all simulations with waves. All waves will propagate towards the bow of the vessel.

Current profiles are omnidirectional and field-specific for simulation with current. Currents and waves will not be present together in a simulation.

Well conditions and operations are not considered in the analysis. The physical/structural limits in the OWCT system is the main focus. The passive heave compensator stiffness is in reality 11% (in IOSS's OWCT system), but the PHC tension variation vs. stroke is not included in this thesis. Wellhead loads have not been considered.

3.3 Verification

Comparing analytical results to simple hand calculations is a good way of verifying the models in Orcaflex. When the deciding what parameters to start the simulations with, hand calculations were performed. Seeing that these coincided with the models in Orcaflex is a good verification method.

Part I

4. What is Open Water Coiled Tubing?

Open water/riserless coiled tubing is performed from a DPMV by running the CT through the sea and into the well without using a workover riser. Similar to riserless WL, both intervention methods involve a DPMV and the use of a subsea stack for lubrication of the toolstring. Considerable differences between a CT string and a wire are:

- The CT can pump fluid
- The wire can handle compression without being damaged, whereas a CT in compression will tend to buckle, which may damage the string. For an OWCT system with tensioned heave configuration, this means that the entire CT string must be kept in tension in the water column (between vessel and subsea stack).
- The CT can “push” the toolstring in well (to some extent)

It can be beneficial to compare an OWCT system to the different well intervention systems to understand the aspects that must be considered in an OWCT system.

4.1 OWCT compared to other intervention systems

Two types of risers exist for use in conventional marine operations from a MODU;

- a low-pressure drilling/marine riser (hereafter referred to as “marine riser”)
- a high-pressure workover riser (hereafter referred to as “WOR”)

An OWCT system can in many ways be compared to both a riser system and a riserless WL system. Simplistically; all three systems involves pipes/wires run through open water. It is hence beneficial to understand the basic differences. While the CT is a continuous pipe and aims to continue into the well after reaching the subsea stack, a riser is jointed and serves as a conduit for equipment/fluids down to the subsea stack. Figure 4 displays the different well intervention systems with associated vessel category [2].

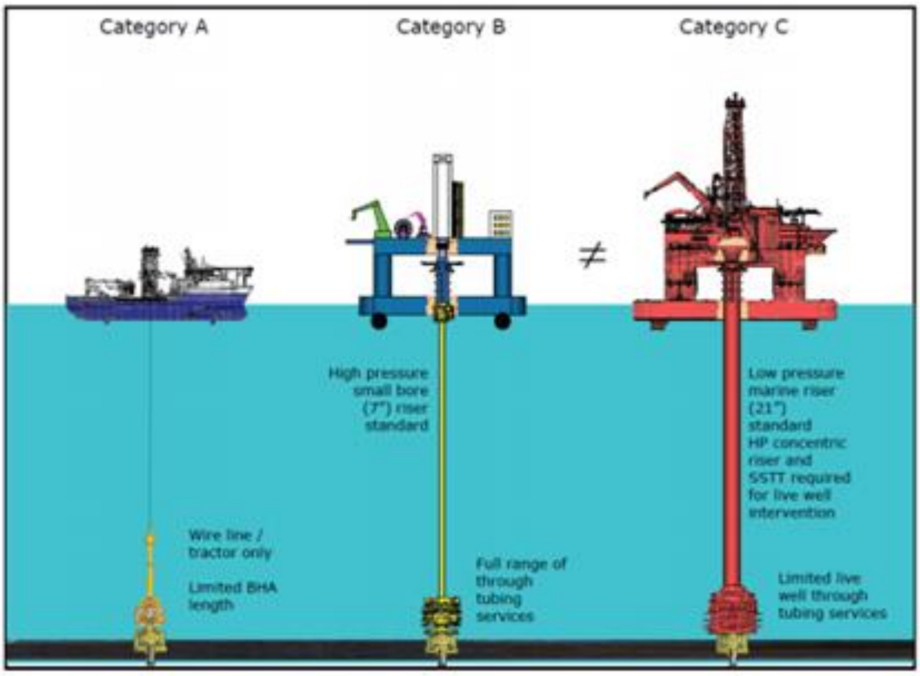


Figure 4 - Vessel categories with associated intervention system

Workover riser:

Coiled tubing well intervention is normally associated with a MODU and the use of a WOR. As opposed to a marine/drilling riser, which only is designed to withstand hydrostatic pressure, a WOR is designed to withstand full well pressure. It is in other words an extension of the well at seabed to the MODU. On a WOR, a lower riser package (for well control) is ran together with an emergency disconnect package and is installed on the XMT. The lower riser package is basically a mini BOP. The WOR serves as a conduit for fluid and equipment, keeping it separated from the sea, and also as the running tool during deployment and removal of equipment at seabed. A WOR typically has an outer diameter of 8-9 inches. A marine riser has in comparison an outer diameter ranging from 21 inches.

Marine riser:

During drilling operations on a subsea well, the BOP is located at seabed. The marine riser is a continuation of the well from the BOP to the MODU. The marine riser serves as a conduit for the drill string, which in turn creates an annulus between the drill string and the marine riser, allowing the drilling mud and cuttings to return to surface. The marine riser is not designed to withstand well pressures, hence the word "low-pressure".

Stress/flex joints:

Flex joints used in a marine riser allows the riser to rotate with the motion of the MODU, and hence reduces the moments transferred to the structure. However, stress joints are used in a WOR as a consequence of allowing well pressures to enter the riser bore. Stress joints are installed as the lowermost riser joints to reduce local bending stresses. To account for the well pressures, the stress joints are consequently more rigid than the flex joints [8]. The stress joints provide fixed support at the structure, and hence a larger bending moment is transferred to the structure. A workover system is depicted below in Figure 5.

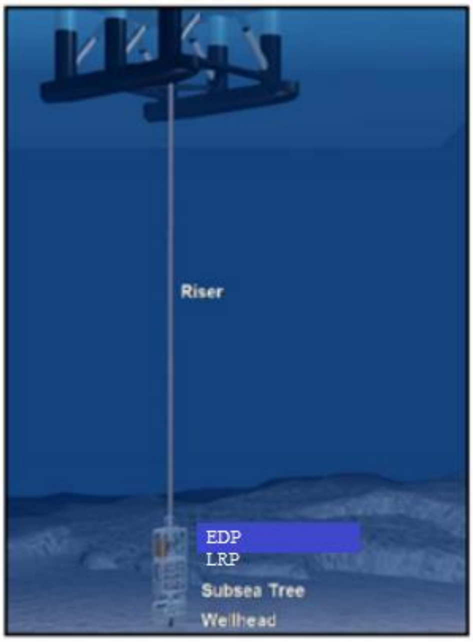


Figure 5 - Conventional workover system

OWCT system vs. riser system:

A WOR deployed from a MODU is a conduit for the CT during intervention. Considering a CT string run through open water and into the well via a subsea stack, one must remember that the CT itself is now acting as a riser, i.e. it is a now a well barrier element and is a part of a barrier envelope, which is subjected to environmental loads. In opposition to riser-based systems, a CT run through open water will naturally continue into the well after it reaches the subsea stack. The points on the CT that experience the highest loads (local hotspots) will hence vary. While a riser uses a stress/flex joint to strengthen the riser at the end points, the CT must be able to handle the loads at the local hotspots on its own. During e.g. a vessel offset, the CT will be subjected to bending, particularly at the end points. A funnel/bellmouth can contribute to reduce the bending moment at local hotspots. Bend straighteners located between e.g. the reel and the gooseneck may also contribute to reduced cycling loading.

Compared to a WOR system, the lubrication of the toolstring in an OWCT system is now moved subsea. Hydrocarbon leaks and other risks associated with lubrication topside are now mitigated. Also, in case of failure in the compensation system, the effective tension in the CT will be far less than for a riser, such that the energy released in a potential recoil will be reduced.

Another difference between an OWCT system and a riser-based system is the ability to handle returns. A WOR is capable of transporting fluids/returns back to surface via the annulus. Fluid pumped through a CT in open water on the other hand, must have separate return lines connected back to the vessel. This may require external subsea pumps, particularly in deeper waters. Another alternative; live wells will most likely be connected to a subsea production system and can be flowed back to installation while running OWCT.

Common OWCT technical problems [9]:

- Synchronization of CT payout at surface and at entering point into subsea stack
- Collapse of CT in deep water, both in water column and in well.
- Maintaining tension in CT in water column
- High utilization of structural capacity of CT in harsh weathers (water depth dependent)

4.2 OWCT drilling vs. well intervention

Even if the purpose of an OWCT system is to perform top-hole drilling or to intervene in a live well, the basic principle is the same: run CT through open water without the use of a WOR. The challenges encountered to enter the hole however, are very different.

When performing OWCT top-hole drilling, there is no need for pressure control equipment at seabed and the returns are dumped directly onto the seabed itself. The low pressures encountered at these depths pose little or no threat to environment, equipment or personnel safety and are considered as reasonably acceptable risks. In opposition, to enter a live well, the toolstring must be lubricated (pressure equalized) to continue its path into the well. Advanced equipment is required to be able to do this. However, by doing so, there is a risk of releasing well pressures out of the well in case of e.g. equipment failure. Subsea well control equipment is thereof needed as a part of a safety barrier envelope to prevent potential pressures to escape from the well.

4.3 Why do we need OWCT from LWI vessels?

Riserless WL performed from a DPMV is already a proven technology for entering live wells. In opposition, a riserless CT system, i.e. an OWCT system, has never been deployed on a live well. So why would it be purposeful to implement OWCT as another alternative?

Compared to WL, it is known that CT has a broader scope of operations. Subsea wells requiring clean-outs/stimulation are of particular interest. The ability to pump fluid, i.e. circulate fluid at desired depth in the well, is the main benefit over WL. Operations performed exclusively by CT (compared to WL):

- Clean-outs
- Stimulation jobs
- Through Tubing Rotary Drilling (TTRD)
- Heavier lifting operations

In addition, a new market for OWCT top-hole drilling may now be on the rise thanks to IOSS's riserless CT drilling operations for The Norwegian Public Road Administration and Centrica. It is now proven that OWCT drilling can be performed. If the concept of OWCT live well intervention were to be realized, the scope for P&A operations could also be extended compared to WL [10].

Figure 6 below displays the current service gap between different vessel categories. A DPMV (Cat A) may currently only perform WL operations, while a CT operation requires a Cat B (or higher) vessel [11].

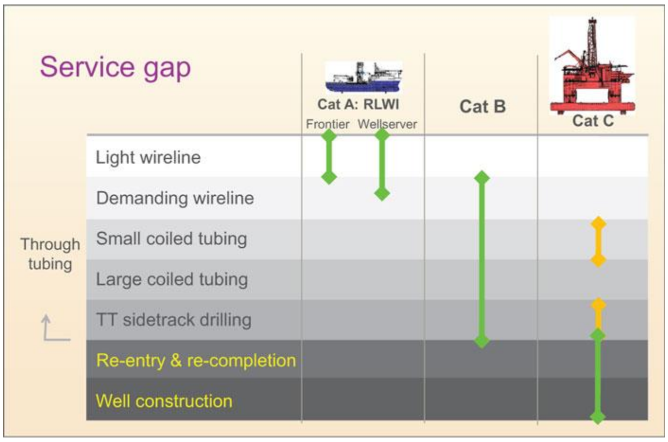


Figure 6 - Service gap [11]

Looking at Figure 7 below displaying operation costs for different vessel categories; if the concept of OWCT well intervention were to be realized, a Cat A vessel would be able to perform the same CT operations as a Cat B vessel, i.e. higher rig rates are avoided.

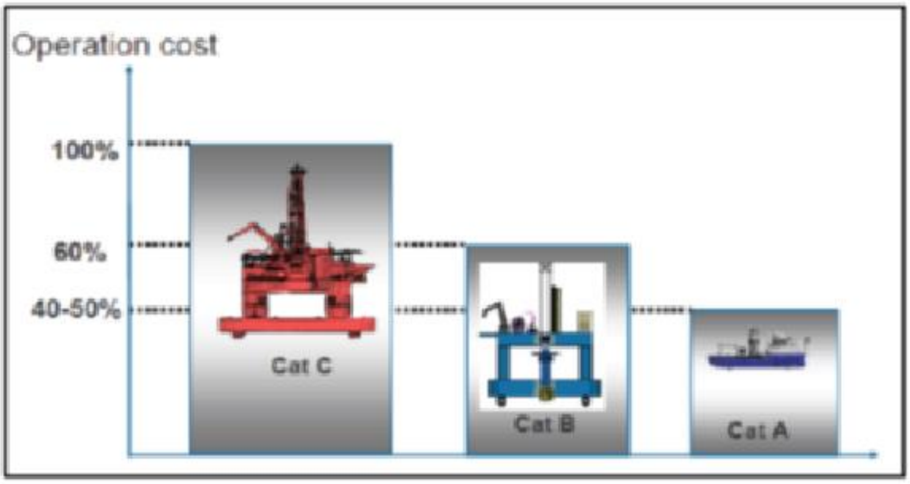


Figure 7 - Operation cost comparison [2]

CT operations performed from a MODU using a WOR is an effective and reliable way of intervening a subsea well. It is a proven method with no technology gaps. However, costs are always a challenge. Mobilization costs have led to fewer interventions on subsea wells compared to fixed installations. CT operations using a

MODU need high value well objectives to be justified. Operators tend to use contracted drilling rigs for drilling or completion rather than for intervention because the outcome is more uncertain. On the contrary; a DPMV is associated with less mobilization time and cost. The deployment system is already installed on the vessel, which means that more time can be spent on the operation itself, rather than on preparations. Hence, it would be more cost effective to use a DPMV than a MODU provided that they can both perform the same operation safely.

The oil and gas industry is constantly exploring to find more oil and gas. By implementing OWCT on Cat A vessels, the number of subsea wells being intervened is believed to increase. This will lead to increased recovery from existing fields.

OWCT is a highly debated subject in the industry. In light of the market situation today (2016), the development of OWCT may be delayed somewhat. The latest rig contracts made on the NCS shows that the rig-rates were at a completely different level than they are today [12]. E.g. Odfjell Drilling's semi-submersible rig Deepsea Atlantic is having a daily income of 566.000 USD from their existing contract with Statoil. In their new contract for the Johan Sverdrup field, starting February 2016, the rig-rate is 300.000 USD [13], which is almost half the rate compared to their existing contract.

Several other rigs will be available within the next years. The competition is currently high and it may be reasonable to believe that the rates will be lower. The rigs are today mainly used for drilling and completion services. Maybe a coiled tubing campaign using a rig could be justified considering the market situation today (2016)? It must however be considered that even though the rig rates are reduced, the oil price is also reduced.

Rates for rigs are, in other words, closing in on the rates for LWI vessels. However, it is also necessary to be aware of the additional costs associated with "service" of the rig/vessel, which comes on top of the day rate. Taking the size of the rig/vessel and the number of personnel on board into account, these costs are typically a lot higher for rigs than for LWI vessels. The following Table 1 represent a comparison of costs between LWI vessels and rigs for well interventions. Numbers represent mean values from previous operations. The table is modified from a presentation made by Øyvin Jensen in Statoil in 2016 [14]. Since the information was internally classified in Statoil, it was decided to compare the costs for the rigs as a percentage of LWI costs. The costs are based on the same operation being performed. The two rigs have different day rates.

Table 1 - Comparison of well intervention costs - LWI vs. rig

	Day rate [%]	Service cost/day [%]	Total cost/day [%]	Anchoring costs [%]	Days of operation [%]	Total cost [%]	Total cost [%]
LWI	100	100	100	100	100	100	100
Rig1	208	113	172	1260	121	258	263
Rig2	92	113	100	1260	121	171	173

From this comparison it is easily that LWI vessels are more cost-effective than rigs. However, the availability of both LWI vessels and rigs are key factors in this instance.

Comment: Multi-purpose vessels could also be implemented as an alternative. RLWI and OWCT from the same vessel could improve well intervention efficiency further.

4.4 History of OWCT

The idea of OWCT is not new to the industry. Many companies have developed a system. Apart from IOSS' OWCT system and ABB Offshore System's RICTIS, it should be mentioned that the following concepts has not been thoroughly investigated but is included to inform the reader that these exist.

- ABB Offshore Systems (GE-Vetco) – RICTIS
  - An introduction to this system can be found in section 9.1
  - Lubricator section located above the subsea injector

- Statoil/Halliburton – SWIFT
  - Coil in coil: does not need subsea injector. The outer coil works as a riser, providing a conduit for the inner coil. Topside injector is sufficient to feed coil. Configuration shown in Figure 8.

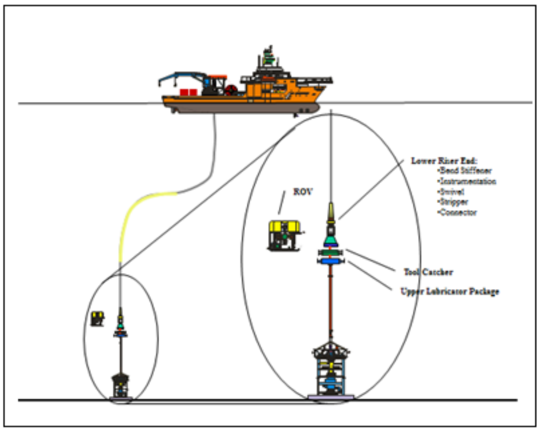


Figure 8 - SWIFT configuration

- GoM/Blue Ocean – OWCT
  - See Figure 9

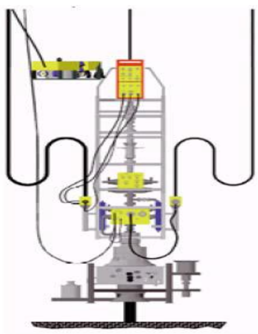


Figure 9 – Blue Ocean - OWCT

- BJ services/Exxon Mobil – SIM
    - See Figure 10

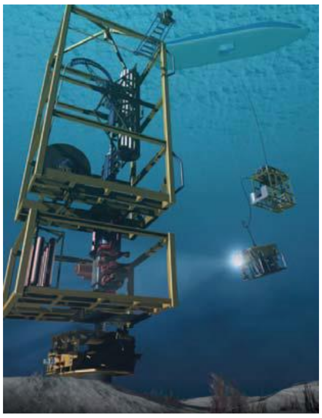


Figure 10 - SIM configuration

Table 2 below presents an overview of the different concepts and associated challenges. The table is a modified version taken from [10].

Table 2 - Overview of riserless CT concepts

Company	Name of the project	Description	Challenges
GoM/Blue Ocean	Open water CT	Coiled Tubing in open water.	To heavy and expensive
BJ services/Exxon Mobil	SIM (Subsea Intervention Module)	SIM was a subsea installed Coiled Tubing system. Reel as well.	To heavy and expensive
GE-Vetco	RICTIS	Open sea	Subsea injector. Fatigue of coil in well
Statoil/Halliburton	SWIFT	Coil in coil	Lock up of coil inside outer coil

CT in riser – performed from LWI vessels (taken from a presentation obtained through Scott Kerr in Statoil [15])

- **Seawell monohull (mid/late 1990's)**
    - Stena-Coflex UK
    - Top tensioned slim HP riser
    - Custom CT injector tension frame
    - Those involved swore they would never do it again
- **AKOFS Seafarer (previously Skandi Aker)**
    - Full-bore HP riser.
    - Conventional riser tensioning under vessel.
    - Operations in Angola failed to mature due to too many technical problems.
- **Helix – Well Enhancer (2010 -)**

- Top tensioned HP riser – fullbore
- Trialed once with mixed success - UKCS
- New attempts being planned – UKCS

4.5 Coiled Tubing Applications

When performing pumping operations, CT is often chosen over conventional drill pipe because the drill pipes must be screwed together. In addition, a workover rig is not required for CT.

CT can be applied to do different operations. These can be separated in to pumping and mechanical applications [16].

Pumping applications:

- Cleanout after drilling
- Formation fracturing/acidizing
- Well displacement/unloading (e.g. nitrogen)
- Fluid cutting of tubulars
- Pumping cement plugs
- Zonal isolation (flow profile control)
- Hydraulic scale removal
- HC, wax and hydrate plug removal
- Gravel packing

Mechanical applications:

- Running plugs, packers or straddles
- Heavier fishing jobs
- Perforation
- Well logging
- Mechanical scale removal
- Mechanical cutting of tubulars
- Sliding sleeve operations
- Running tubing/completion
- CT drilling (e.g. TTRD)

4.6 New definition of risk

The Norwegian Petroleum Safety Authority (PSA) implemented a new definition of risk this year (01.01.2016) [17]. Risk is now defined as "consequences of activities with associated uncertainties". Uncertainty involves lack of information, lack of understanding or lack of knowledge.This basically means that the risk will be less for known and proven solutions, since there is less uncertainty. However, it also means that new and unknown solutions may have increased risk, which may for example imply that additional safety margins are implemented. The new definition of risk ensures that knowledge is given a "value" in order to more accurately determine the risk.

Considering the above, an OWCT well intervention system may now be associated with larger risks than before. The uncertainty, i.e. the lack of experience, with such a system means that previously assumed risk levels now may be higher.

5. Coiled tubing equipment

This chapter serves to provide a general coiled tubing equipment overview. Fundamental system principles and components will briefly be presented.

The fundamental CT topside/surface equipment to handle the CT in an OWCT system will be more or less the same as for conventional platform-based CT operations. However, the pressure control components are now stacked on top of the XMT and wellhead at seabed.

5.1 Conventional Coiled Tubing Equipment

Conventional CT operations performed from a platform will have all the necessary equipment located at surface since the wellhead is located on the platform. This section provides a description of the system components.

A typical offshore CT rig-up, as illustrated in Figure 11, consists of a reel with the CT, a tubing guide (gooseneck) mounted to an injector head, a control cabin, a power pack and a well control stack. A jacking frame, not shown in the figure, provides the require height to stack the equipment.

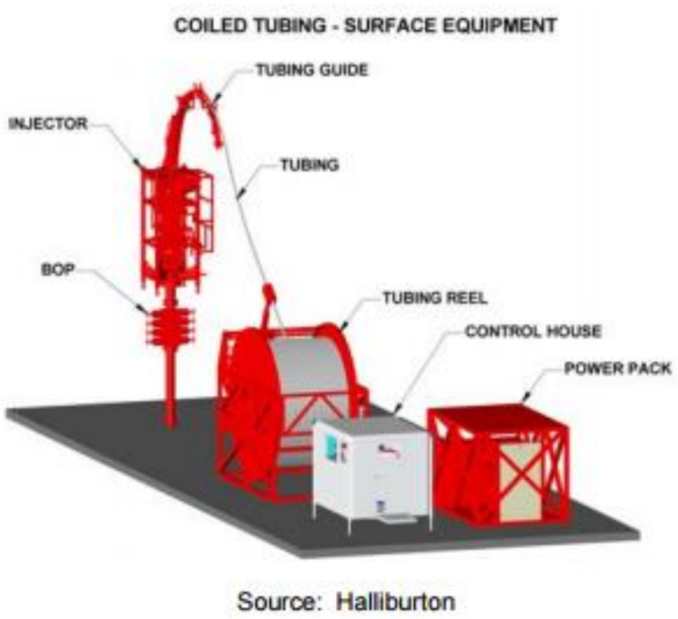


Figure 11 - CT surface equipment [18]

5.1.1 Coiled tubing string

CT is a continuous piece of welded steel tubing without connections that is spooled on to a reel. The continuous process of bending and straightening events of the CT makes it prone to fatigue. The CT string is thus regarded as a consumable product with limited service life. Analyzing and managing the factors contributing to increased fatigue are key elements to ensure safe and effective operations.

5.1.2 The Reel

The reel is used for storage and transportation of the CT. The CT is spooled off the reel while running into hole, and spooled onto the reel when pulling out of hole.

5.1.3 Injector Head

The injector head is the main engine when performing CT operations. The injector head model may vary with CT size. The three main functions are as follows: [19]

- Supply enough thrust to snub the CT into the well. Well surface pressure and friction forces must be accounted for.
- Control the rate when running into hole (RIH) or pulling out of hole (POOH)
- Hold the weight of the entire CT string in well. Acceleration when POOH must be accounted for.

The next subchapters provide an overview of primary components of a typical injector.

5.1.3.1 Gooseneck

The gooseneck, as shown in Figure 12, is mounted on the injector and guides the coil from the reel into a vertical alignment with the injector and the well. The radius of the gooseneck is designed to be as large as practicable to minimize fatigue on the CT string (minimum arc radius must at least be equal to the core diameter of the reel).

Figure 12 - Gooseneck mounted on an IH (modified version from [20])

5.1.3.2 Chain tensioning system

Figure 13 below illustrates the chain drive system as a part of a Hydra-Rig 240/260 injector head. This is a typical example of a skate chain tensioner system. Explanation follows Grindheim [21]. The chain is driven through the top sprocket (1) by means of hydraulic motors. The skates, functioning as the inside tensioner (2), are linked in pairs with hydraulic cylinders providing the force required for the chains to clamp on to the CT. The “slack” created on the chain outside is controlled and removed by the sprocket (3). It is important to maintain tension in each chain to ensure a smooth operation and to prevent damage on the CT. Improper chain tension may offset the chain links causing the grippers to “scratch” the CT surface or worse, cause a CT “runaway”. A CT “run-away” is an uncontrolled run-in of CT into the wellbore.

Comment: Correct chain tension may be especially important for an OWCT system, where waves and currents can cause additional motion. Since the CT will have direct contact with the ocean environment, it is inherent to an OWCT system that failure of the CT in open water will cause spillage of the content.

Comment to Figure 13: One side of the injector is removed for illustrative purposes. The injector is symmetrically shaped, i.e. the opposite side is a mirror copy of the revealed side.

Drive sprocket (1)

Inside tensioners (skates) (2)

Outside tensioners (sprocket) (3)

Lower idling sprocket (4)

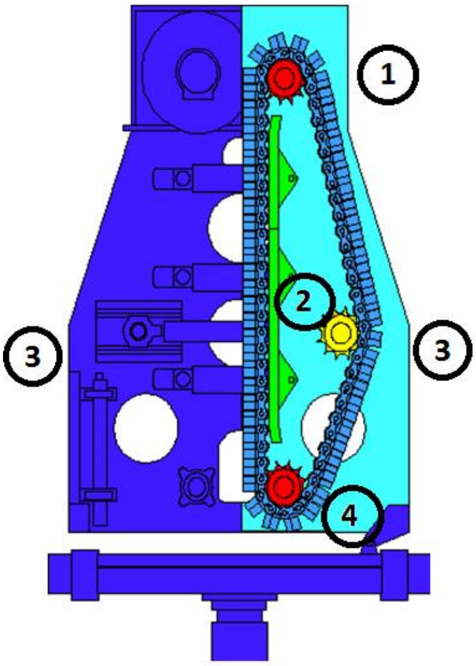


Figure 13 - Sketch of tensioner system (modified version from [21])

5.1.3.3 Injector head chains and grippers

Inside the injector there are two opposing rotating chains with associated gripper blocks connected to each chain link as illustrated in Figure 14 below.

Comment to Figure 14: The pictures shown are not practicably connected to each other in any way, except for illustrative purposes.

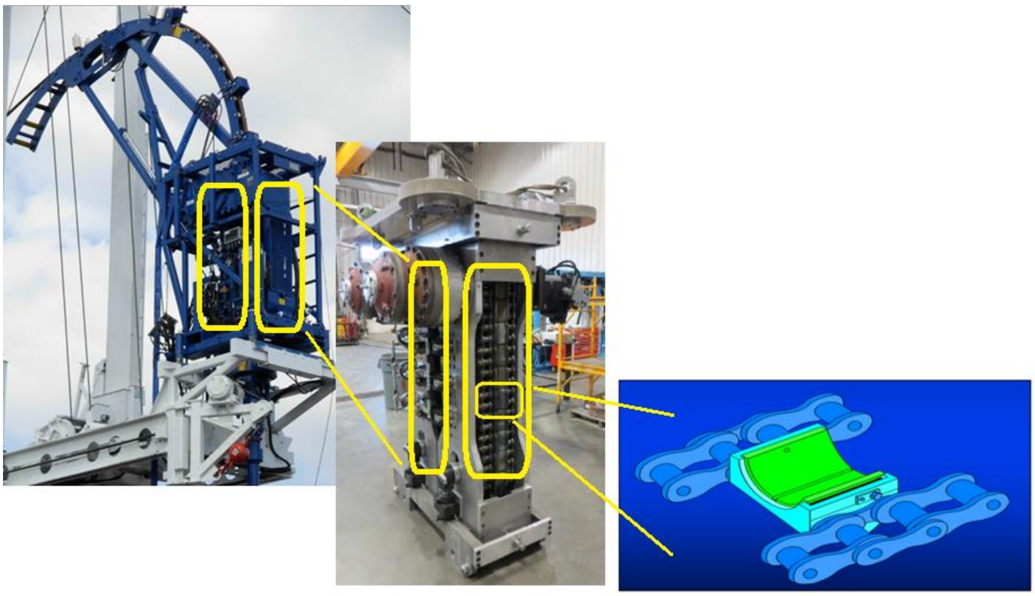


Figure 14 - Zoomed in: IH chain link and gripper block

The gripper blocks are pressed against the CT by means of hydraulic cylinders, providing the friction required to grip the CT while running in or pulling out of hole. The numbers (1 & 2) in Figure 15 represent the lateral forces acting on the CT when the gripper blocks are "pushed" against it.

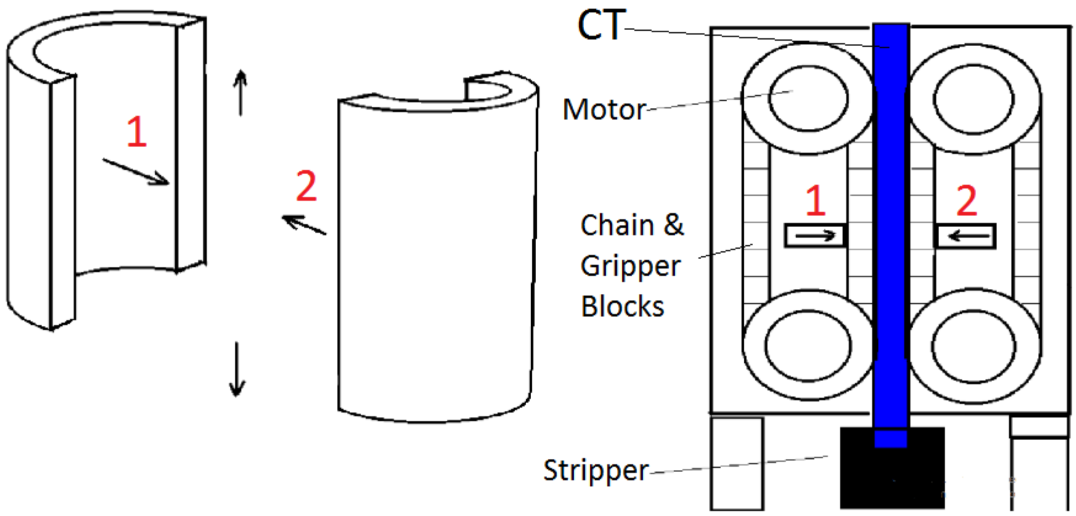


Figure 15 - Illustration of gripper block function (modified version from [20])

5.1.3.4 Motors and brakes

The injector head chains are usually driven by two or four hydraulic motors, which are synchronized via a gear system. The torque is transferred to the sprockets by means of drive shafts. The speed of the motors can be adjusted by a valve on the power pack. The brakes are hydraulically controlled, i.e. hydraulic pressure is needed to release the brakes (fail-safe).

5.1.3.5 Weight indicator

It is critical that the injector is equipped with a weight indicator that measures the tensile load in the CT above the stripper, with the weight measurement displayed to the equipment operator during well intervention or drilling operations. There should also be a weight indicator that measures the compressive force in the tubing below the injector when CT is being thrust into the well. [19]

Comment: In an OWCT intervention scenario, tension/compression should be monitored at two places; just below the vessel (the part of CT in water) and below the subsea stack (the part of CT in well).

5.1.4 Control Cabin

The control cabin is the primary control center for the CT operation. Here, the operator is allowed to control and monitor all circuits and parameters from a single station. The applications involve:

- Control of CT
- Control of BOP
- Monitoring equipment

The control cabin is also equipped with a coiled tubing sensor interface (CTSI), which has the purpose of recording and monitoring of all sensors. The CTSI is connected to a laptop computer providing real-time operational data for the operator [21].

5.1.5 Power Supply Unit

A power supply unit, usually called a “power pack”, is the power generator for a CT operation. It is driven by either a diesel or an electric engine, providing power to hydraulic pumps to further power individual systems. This includes the accumulators for the BOP. [21]

5.1.6 Pressure Control Surface Stack

The well control stack, shown in Figure 16, contains the pressure control equipment required for entering a live well from a platform. Typical stacks (from top to bottom) consist of a stripper, a coiled tubing blowout preventer (CT BOP) and most operator companies, including Statoil ASA, has in addition a requirement involving a safety head between the CT BOP and the XMT.

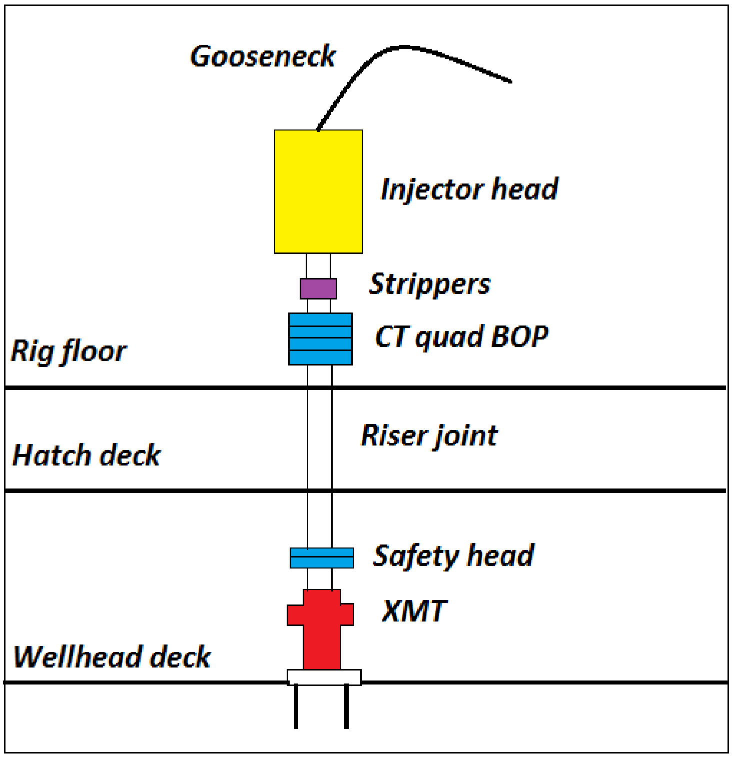


Figure 16 - Pressure Control Surface Stack

5.1.6.1 Stripper

The stripper, containing rubber elements, is located directly below the injector, and serves as the primary barrier against well pressures by sealing around the CT. Two strippers are conventionally used in a CT operation, where the upper stripper is the active barrier element, while the lower stripper is redundant in case of failure or repair is needed for the upper stripper.

5.1.6.2 Coiled Tubing BOP

Below the stripper is the BOP, which acts as the secondary barrier (Figure 17). The main function of the BOP is to seal the well in case of an emergency and is a part of the secondary well barrier envelope. A typical CT BOP has the following abilities with associated rams:

- Seal the well when CT is not present across the BOP (blind ram)
- Cut the CT (shear ram)
- Hold the CT in place and support the CT weight hanging below (slip ram)
- Seal the space around the CT (pipe ram)

Figure 17 – CT BOP

5.1.6.3 Safety Head

A safety head containing a shear seal ram is to be located as close to the XMT as possible. It is usually placed directly on the XMT with only one connection in between. This minimizes the number of leakage points. The requirement connected to a tertiary pressure control device (safety head) is a result of earlier experiences. The reason for the implementation of the safety head is in cases where the CT toolstring is so long that the top of it will block the shear-blind ram in the CT BOP before the bottom of the string has passed the XMT. The shear seal ram in the safety head is more powerful than a regular shear blind, and is designed to be able to cut up to three parallel CT strings and at the same time seal off pressures from below. [22]

5.2 Conventional tool deployment

The injector together with the strippers is skidded aside prior to tool deployment. The bottom hole assembly (BHA) is then lowered past the CT BOP and into the riser joint, i.e. the lubricator pipe, residing between the CT BOP and the safety head. The surface XMT is the primary barrier against the well pressures now, while the DHSV acts as the secondary barrier. When the BHA is placed, the injector and the strippers are skidded back and are then put on top of the CT BOP. Before the pressure can be equalized the riser joint must be pressure tested. This is usually done with seawater or brine. The swab valve on the XMT can be opened when the pressure is equalized, and the BHA can continue its path into the well.

5.3 OWCT system description

When moving a CT system from a platform to a DPMV, figuratively speaking, several changes must be implemented to the system to handle the new challenges. Remember that all pressure control equipment (the subsea stack) is now attached to the well at seabed, as it is with RLWI. One difference is the amplified vessel motion response due to environmental loads. Another is that the CT is now run directly through the sea. This implies that new system components must be introduced to ensure a comfortable risk- and safety level throughout the operation. An illustrative comparison figure is shown below in Figure 18. Note that the distance between platform and MSL is not included. Description follows in the next sections.

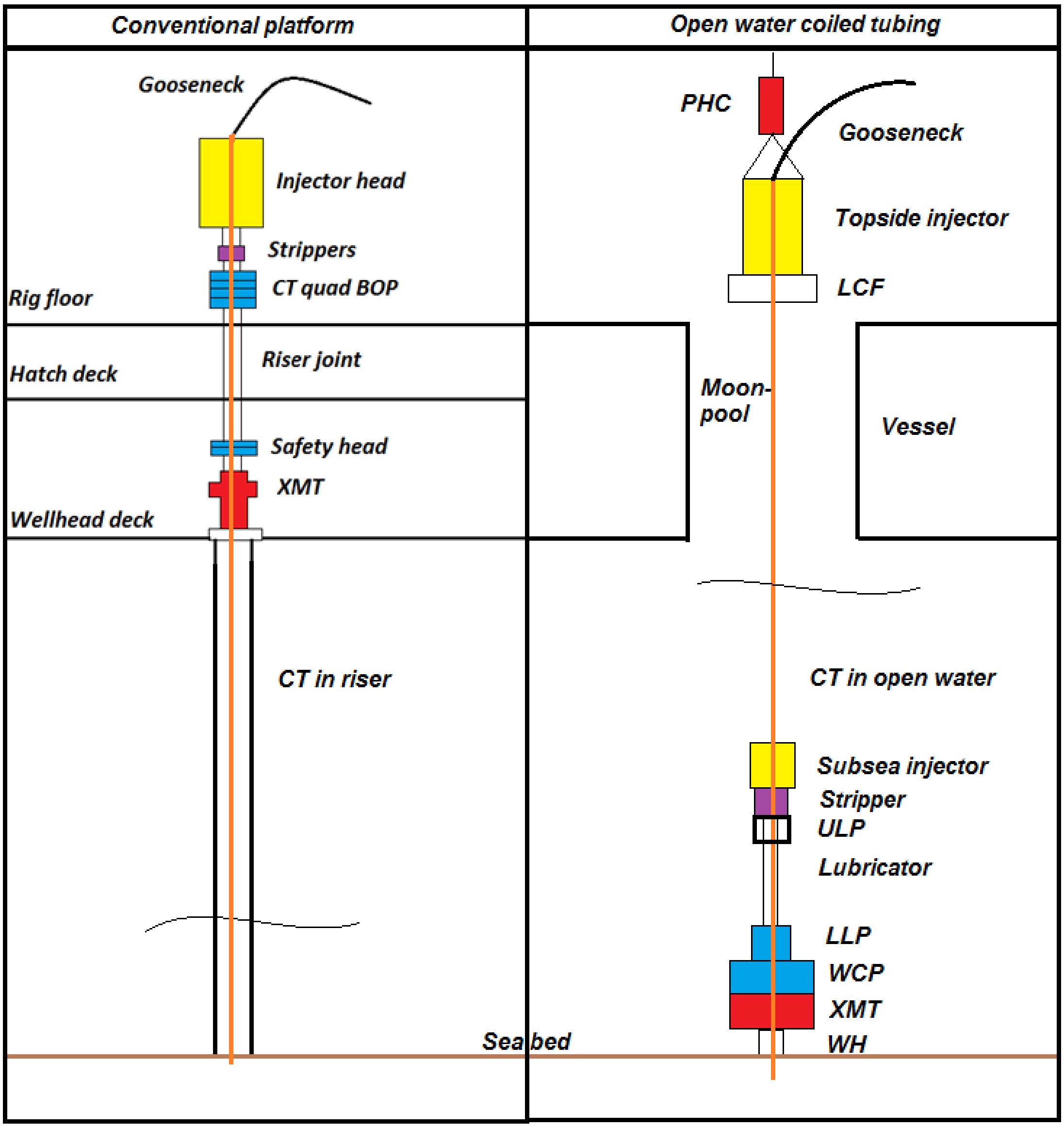


Figure 18 - Conventional vs. open water CT

The description of the OWCT system components is generalized based partly on IOSS's drilling operations on Butch, and partly on their future plans for the OWCT well intervention concept. All figures are provided by IOSS.

OWCT drilling will not be given attention, since focus in this thesis is directed towards an OWCT live well intervention system. A common feature, though, is the equipment located on the vessel. In Figure 19 below is a sketch of the OWCT well intervention system.

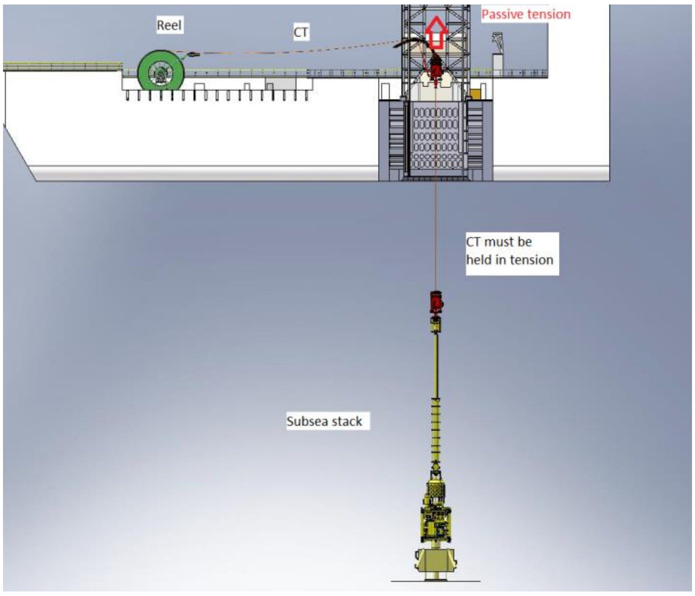


Figure 19 - OWCT well intervention system

Since OWCT systems still are in the concept phase, developers should try to exploit already existing equipment and technology. In addition to reduce costs involved with testing and verification of new technology, using existing technology can provide empirical information, i.e. experience. E.g. IOSS used a modified surface injector as a subsea injector in their CT drilling campaign for The Norwegian Public Road Administration [23].

5.2.1 Topside Equipment

General equipment such as the reel and the topside injector (TSI) are the same as used for conventional CT operations from a platform or MODU. Referring to Figure 20 below, a difference is that, during operations, the TSI is now placed on a Lower Cursor Frame (LCF) which is connected to the intervention tower. The connection between the LCF and the intervention tower is such that the LCF is allowed to slide up and down along the tower as the vessel heaves. The LCF is further wired to the Passive Heave Compensator (PHC). The applied top tension in the CT string is determined by the PHC tension setting. The PHC attempts to keep the LCF and the TSI stationary in vertical direction relative to the well. The PHC is further attached to a hook (not seen in the figure) controlled by the main winch, i.e. the Active heave compensator (AHC).

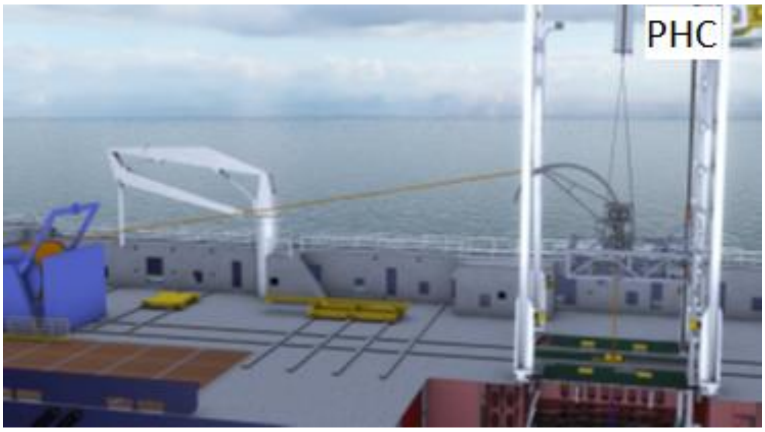


Figure 20 - OWCT topside equipment

Comment: Note that the CT reel is placed a considerable distance away from the gooseneck. This is done to minimize reel rotation as the injector heaves.

5.2.2 Subsea equipment

The subsea stack in Figure 21 below is based on IOSS' ongoing development together with FMC Technologies. It should be specified that the properties, the dimensions and choice of components to include in the subsea stack is still an ongoing project for IOSS. The Orcaflex model of the OWCT system described later in this thesis includes more components than specified here. A CT BOP between the stripper and the ULP (upper lubricator package) and a safety head between the WCP (well control package) and the XMT will be present. Many of the components are described in Section 5.1, and will not be described here. However, the components are now subjected to the ocean environment, and must be tested and verified to handle such conditions. Appearance and design may differ from conventional equipment, but the functionality is the same.

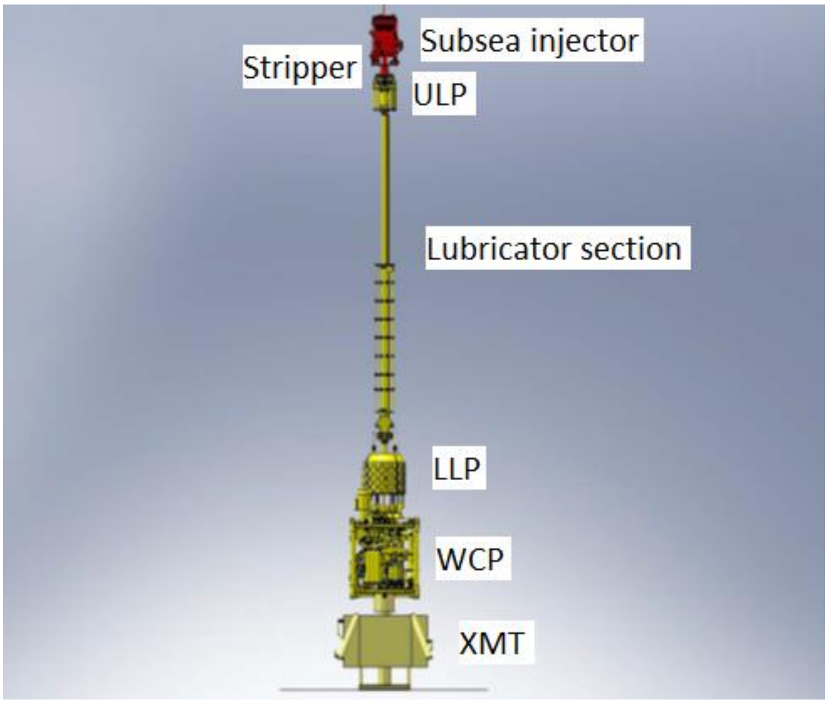


Figure 21 - CT subsea stack

Subsea Injector:

The subsea injector (SSI) is the uppermost component in the subsea stack. The subsea stack used in the Butch operations [23], was a modified topside injector. The SSI is critical when the applied tension in CT is concerned. Without the SSI, there would be no way of establishing positive effective tension in the entire CT string between vessel and well. A heavy toolstring can however ensure positive effective tension in CT in the water column, but upon entering the well, the well pressures can cause the CT to go into compression. A device such as the SSI close to the well is therefore necessary to maintain a tensioned heave configuration during the entire operation. The weight of the CT in the well is held by the SSI, while the weight of CT in water (plus the applied top tension) is held by the TSI which in turn is held by the heave compensation system.

Stripper: Function explained in section 5.1.6.1.

Upper lubricator package:

The ULP acts as a barrier element during intervention. It is installed with a subsea lubricator valve with cutting capacity.

Lubricator section:

The lubricator is equipped with valves to bleed off pressures, allowing safe connection/disconnection of the toolstring from the well. A lubricator can be looked at as a chamber required for hosting the entire toolstring. It must also be able to hold the well pressures after equalizing. The toolstring must never be longer than the lubricator section, as valves are then unable close. A leak in the lubricator during pressure equalization would result in well pressures entering, in this case, the ocean.

The lubricator is placed above the LLP and the WCP. The integrity of the main barrier elements are thus preserved if the lubricator should fail.

Lower lubricator package:

The LLP is a safety joint, designed to bend if the stack experiences excessive forces. Contains control modules for all functions on the lubricator section.

Well control package:

The WCP is the main safety barrier in the stack. It contains a shear/seal ram which is able to cut CT. It enables flushing of hydrocarbons back into the well. It provides hydraulic pressure and communication to XMT functions.

5.4 OWCT tool deployment

The subsea injector (SSI) and strippers, initially located on surface, is lowered down in open water together with the CT and toolstring using two guide wires. The SSI and strippers is then attached to the top of the ULP by aid of an ROV, while the CT toolstring is lowered into the lubricator. The topside and subsea injector are both operated manually. The SSI is currently run via hotstabbing through an ROV.

Having the SSI placed as the uppermost component of the subsea stack has both advantages and disadvantages. Upon retrieval of the toolstring, the SSI and the strippers must also be pulled to surface. Like any other injector, the gripper blocks in the SSI (along with the strippers) are designed to handle a constant outer diameter of the CT. This is obviously more time-consuming relative to a design that would enable pulling of the toolstring alone. However, an advantage with pulling the SSI and strippers together with the toolstring is the possibility to inspect them at surface between runs. The OWCT drilling operations carried out by IOSS for Centrica and the Norwegian Public Road Administration (Statens Vegvesen) was done successfully using this method [23].

It is important to note that these drilling operations were done without using subsea pressure control equipment, and returns were dumped directly onto seabed. However, the method of pulling the SSI and strippers together with the toolstring is the same.

5.5 Coiled tubing fatigue

Addressing CT fatigue is of importance. The work of this thesis is not targeting coiled tubing fatigue in specific, but addresses it as a challenge that must be considered in the design of an OWCT system. The following section will provide an introduction to coiled tubing fatigue.

Fatigue – the process of progressive localized permanent structural change occurring in a material subjected to conditions that produce fluctuating stresses and strains at some point or points and that may culminate in cracks or complete fracture after a sufficient number of fluctuations. [24]

There are generally five conditions affecting the working life of the CT [25]:

- Bend-cycle fatigue
- Internal pressure loading
- Applied axial loading (tension/compression)
- Corrosion
- Mechanical damage

Reinås [26] describes mechanical fatigue as "*a time dependent failure mechanism, or more precisely, number of load cycles dependent*". The repeated deployment and retrieval of the CT causes it to be subject to continuous bending and straightening events, which often is referred to as "bend-cycles" or "bend-events" [25].

When the CT is subjected to these bending cycles, the material of the CT will plastically deform as a result of bending beyond the elastic limit of the material, which leads to a gradually weakening of the CT. Figure 22 below illustrates the bending events during deployment (bending event 1 to 3) and retrieval (bending event 4 to 6) of the CT from a fixed installation. The sequence is explained in [25] and is as follows:

- *The tubing is pulled off the service reel by the injector. The hydraulic motor on the reel provides resistance to the pull of the injector, placing the tubing in tension. The tension applied is typically limited to the amount needed to bend* *the tubing over the tubing guide arch and maintain control of the tube during deployment. Therefore, the tubing is straightened out somewhat, constituting the first bend event.*

- *Once the CT reaches the tubing guide arch, the tubing is bent over the prescribed radius. This event constitutes the second bend event experienced during deployment.*
- *As the tubing travels over the tubing guide arch, the tubing is returned to the straightened orientation before entering the gripper blocks in the injector (third bending event).*

These three bending and straightening events are repeated in reverse as the tubing is extracted from the well, resulting in a total of six bending events commonly described as a "trip".

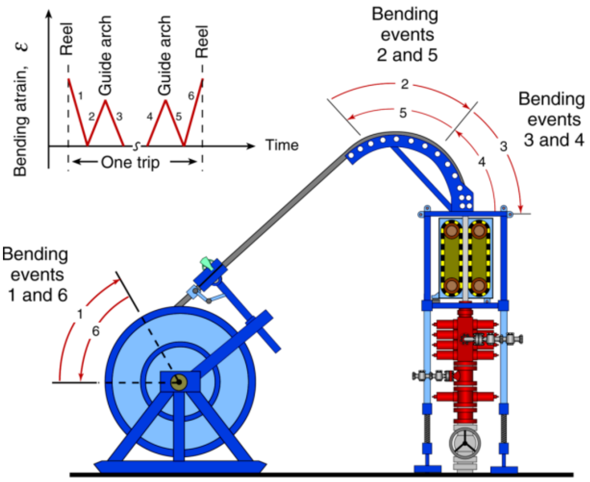


Figure 22 - Bending Cycles [25]

Comment: The ability of an OWCT system to reduce the cycling loading on the CT itself due to vessel motions is critical to ensure a long working life [27]. A CT string run through open water and fixed to both vessel and well must be kept in tension to avoid buckling of the string as the vessel heaves. If the deployment of the CT is paused when the heave compensation system is compensating for the vessel motions, the CT string is constantly being reeled on and off the reel to keep the CT at the same depth. This causes the CT to be subjected to additional bending cycles on the same section, i.e. increased number of "trips". The CT working life will hence be severally reduced on that section of CT.

6. Positioning systems & motion

6.1 Dynamic positioning systems and anchors

A platform is rooted solidly to the seabed, and does not experience motion due to e.g. waves and currents. The only operational weather limitations (unless the platform must be evacuated due to extreme wave heights) are the wind speed and the wind direction. In opposition, a semi-submersible rig is either anchored to the seabed or/and has a dynamic positioning (DP) system to avoid larger offsets from the rigs desired position. In other words: the ability to withstand the lateral forces induced by weather (wind, waves, and currents). Figure 23 displays the eight anchors (black circles) holding Bideford Dolphin in place above the Vigdis G template. In addition to the anchors, Bideford Dolphin has two thrusters to aid in positioning. These are however not powerful enough to function as a DP system on their own (without anchors). The straight lines in pink color represent the steel chain/carbon fiber cables connected to the anchors. Anchor deployment is dependent on water depth. The anchors are, in this case, placed up to approximately four kilometers away from the rig itself.

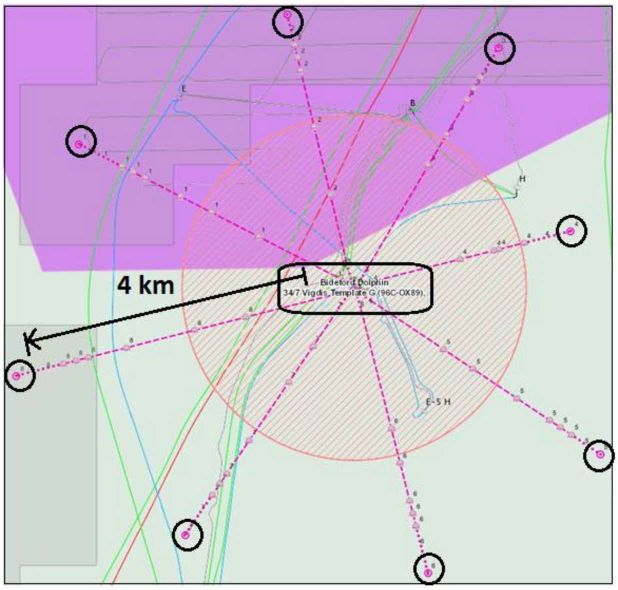


Figure 23 - Bideford Dolphin anchors, 17.02.2016

Even though operability with regard to weather limitations is dependent on thruster power on a DP system to maintain position, using anchors may be more robust against harsh weather. However, anchoring up a rig require mobile vessels (boats) to pre-transport the anchors to the drop-off location. This is a time- and cost consumer, possibly making a DP system the preferred option for shorter operational durations on the same location. However, the water depth must also be considered. The inclination angle of the riser increases faster due to loss of position in shallow waters. A DP system may then not be the preferred option.

In opposition, a DPMV’s ability to maintain its position is solely based on the thrusters ability to counter-act the external loads. The DP system on a DPMV should therefore have redundancy, i.e. class 2 or 3.

For vessels that only avails a DP system, a loss of position (offset) is either caused by a drift-off or a drive-off. A drift-off is an uncontrolled loss of position caused by external forces (wind, waves and currents), and is usually a result of either a failed DP system or a system power loss (loss of mooring lines for rig). Both intervention equipment and subsea structures may suffer great consequences as a result of an uncontrolled drive-off. Example of potential scenario: the heave compensation system can only compensate for waves provided it has sufficient stroke capacity. As the vessel is displaced horizontally, the heave compensating system will attempt to keep a constant effective tension in the CT (the bending moments at end points will however increase). As soon as the stroke capacity is reached, the heave induced by waves will not be compensated for, and the CT/riser will experience great loads. This is an accidental scenario.

A drive-off is a loss of position as a consequence of a malfunctioning DP system. The vessel now changes position due to the thruster force, and not the external loads. A drift-off is considered to be more critical than a drive-off because it give the crew less time to respond, i.e. initiate counter-measures.

6.2 Motion and heave

The conventional CT equipment elaborated on in the previous chapters is the basic equipment needed to perform a CT operation. Extra equipment is required depending on what type of installation the operation is performed from.

During operations on a semi-submersible rig or a DPMV, where surface equipment is attached to equipment down-hole or at seabed, the surface equipment must be heave compensated. A riser or CT string can experience large load variations due to wave-induced movement of the vessel. The main functions of a heave compensation system are to:

- Reduce the CT motions
- Keep constant tension

A heave compensation systems function is to reduce the vertical movement induced by waves on the load being compensated (cancelling out effect of waves). On a vessel or a floating rig, a heave compensation system can be seen on as a necessity for performing safe and effective operations.

6.2.1 Passive and Active Heave Compensation

There are in general two types of heave compensation systems: [28]

(1) Passive Heave Compensation (PHC)

(2) Active Heave Compensation (AHC)

Shock absorbers, drill string compensators, and WL tensioners are all examples of simple PHC systems. The fundamental principle of a PHC system is to accumulate the energy from external forces (in this context: waves) and reapply it later on. A PHC device acts as a soft spring that allows relative motion while suspending the load (compensates for load variations). PHC differs from AHC by not requiring power supply. Figure 24 below illustrates a simple PHC system installed to a wire spooled off a winch. The hydraulic cylinder is attached to the top sheave. The load is now shared between them. The cylinder is connected to an accumulator and two gas bottles containing high pressure gas. The gas bottles are required depending on the stiffness of the system. The pressure acting upon the piston is dependent on the piston position. When the piston moves down, the total gas volume is reduced. This increases the pressure acting on the piston.

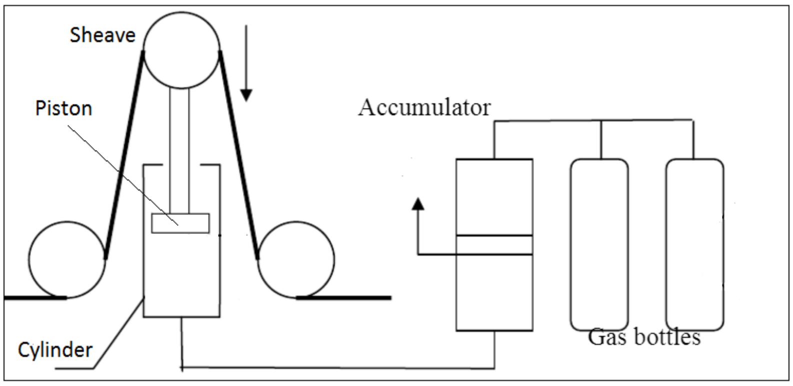


Figure 24 - PHC system principle (modified version from [28])

AHC has the same function as PHC, but differs by using a powered control system to compensate. Another difference is that PHC uses a spring concept, while AHC uses a motion reference unit (a sensor) that monitors the vertical acceleration, velocity and heave of the rig or vessel. The control system then calculates the required action that is to be executed by the active parts of the system to compensate for the motion. Further explanation of AHC will not be weighted in this thesis.

The heave compensation system in IOSS's OWCT concept consists of both a PHC and an AHC as seen in Figure 25 below. The PHC has a stroke capacity of 7m while the AHC (the main winch) has a stroke capacity of 5m, which in total is a capacity of 12m (double amplitude). Stroke capacity is limited by a number of factors, which is explained in the next section.

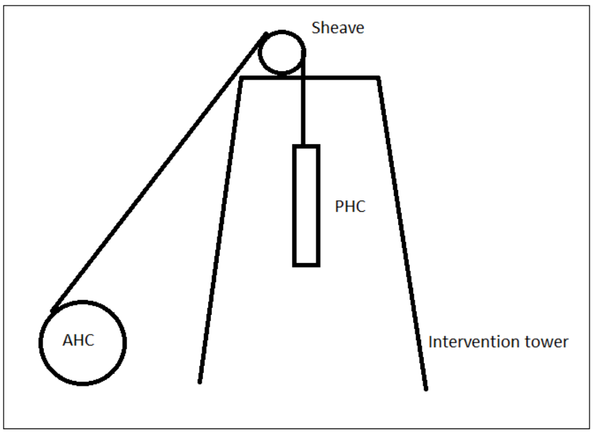


Figure 25 - OWCT heave compensating system

6.2.2 Heave Compensation Limits

A heave compensation system has limitations. When utilizing a PHC in an OWCT the stroke is an important factor to consider.

Riser stroke is the relative vertical motion between the vessel and riser [7].

If the available heave compensator stroke capacity is used to compensate for riser set-down, there is no capacity left for vessel heave motion. Conversely, if the vessel heave range is close to or equal to the compensator stroke range, there is no surplus length to provide for riser set-down. The ultimate consequence is stroke-out, which will usually cause a large increase in riser tension. The stroke-out may result in parting of the riser or damage to subsea well. Shallow water and high vessel offset are usually the most critical conditions [7].

More information about heave compensation limits can be found in Appendix A. This is directly copied from API standard 17G [7].

7. OWCT – Design and functional requirements

The overall requirement for an OWCT system is to develop a riserless CT intervention system that can be used from a DPMV. The system objective, in addition to have reduced deck load and area requirement, is to be more time and cost efficient compared to riser based systems.

An OWCT system should be evaluated based on the relevant water depth of the area it is meant to be deployed. Feasibility studies on systems meant to be deployed on the NCS should concentrate on depths from 100m to 500m. The OWCT system must also be applicable to enter and perform CT operations on both vertical and horizontal XMT's.

The following sections provide an overview of the design considerations and functional requirements based on ABB Offshore's feasibility study regarding the RICTIS system [29].

7.1 Well Control Requirements

Maintaining well control throughout a well intervention operation relies on:

- The barrier envelope comprising the barrier elements
- The degree of reliability and redundancy tied to the barrier elements
- Alternative backup solutions to replace lost functions

The principal objective should be to design a system that, independent of the circumstances, makes it possible to leave the well in a safe mode. No single equipment or operational failure should cause an uncontrolled event that can pose a threat to equipment, people and environment.

7.2 Coiled Tubing Requirements

In an OWCT system the CT shall be run in open water between the vessel and the well without the use of a workover riser. Regarding CT characteristics, the system must be able to handle/operate:

- varying CT dimensions
    - RICTIS: 2" to 3.5"
    - IOSS OWCT: most likely 2 3/8" to 3 ½" (2 7/8" is base case)
- a specified total length of the CT

7.3 Vessel Requirements

The vessel required to operate an OWCT system must meet certain general requirements:

- Capable of storing the OWCT system components and, depending on type of campaign, additional systems such as WL.
- Specification of DP class (RICTIS: class 3) and redundancy, or an anchor system.
- Handling system for handling of equipment at surface and in and out of the sea.
- A compensation system is an absolute necessity for:
  - Equipment compensation during running and retrieval of subsea units
  - Compensation of CT while running in and out of well
- The vessel must have pumping equipment with a specified capacity to perform the planned pumping operations, and in addition, capacity to kill the well.
- The vessel must be able to store and deploy Remotely Operated Vehicles (ROV).
- The vessel must contain a moonpool (size of area must be specified).
- Crane capacity must be high enough to lift the required equipment.
- The vessel must provide accommodation for the crew
- Sufficient deck area to host the system equipment
- The vessel must be capable of hosting a rig system over the moonpool, accommodating potential guiding and hoisting facilities.

7.4 Subsea Stack - Requirements

A common element in an OWCT system is the subsea lubricator section. The lubricator pipe itself is a high-pressure pipe designed to accommodate the CT tool string, commonly called bottom-hole assembly (BHA), and lubricate (pressure equalize) this into a live well. The lubricator section must at any time keep the barrier envelope between well and environment intact. Several requirements must be fulfilled by the lubricator section. These are summarized below:

- Sufficient tool length to host the BHA for all the planned operations.
- Installation and retrieval must be possible to do with CT.

- Must be capable of forming the primary well barrier element during lubrication.
- Must contain equipment to keep the CT from collapsing (bending restriction).
- Must be able to handle the bending load if “slack” occurs in the CT (CT hanging in free water).
- Bending moment on subsea stack (RICTIS’ weak link in the subsea stack: the lubricator package)

7.5 Control System Requirements

A control system is necessary to control and monitor the components in an OWCT system.

8. OWCT - Operational Weather Limitations

One of the main hindrances for utilizing an OWCT system in the North Sea is the weather conditions. What is the point of using such a system if weather conditions are exceeding the operational limits most of the time? And how much productive time is necessary to make an OWCT system profitable? These are key questions that need specific answering.

Establishing estimates for the operational weather limitations requires several conditions to be evaluated:

- The vessel position offset limit (drift off) must be evaluated for various water depths.
- Operating circles (green, yellow and red zone) and timeframe for safe disconnect are key elements that must be established.
- Handling of equipment on deck and inside tower during harsh weather (wind, waves)
- Simulation of disconnect scenarios (CT, umbilical) and stress/load calculations during these.
- Loads and stresses on WH and subsea stack
- Critical contact point – shearing between vessel system and subsea system
- Fatigue (high cycle, low cycle), coil life
- Vessel motion limits (e.g. pitch, heave)

9. Riserless Coiled Tubing Projects

The idea of OWCT is not new to the industry. Many companies have tried to develop a system. The RICTIS project is further elaborated in the next section.

9.1 ABB Offshore Systems - RICTIS

ABB Offshore Systems (now GE Vetco) published in 2001 their RICTIS project. RICTIS – "Riserless Coiled Tubing Intervention System" – was evaluated by Statoil, but the project was abandoned. Description is based on [3].

According to ABB Offshore Systems [3], the novel steps in the RICTIS project were the lubricator system and the use of a tensioned CT configuration. The lubricator is located <u>on top</u> of the subsea injector, and an additional injector is located at surface. A heave compensation system at surface, together with the two injectors, provides the ability to control the tension between vessel and well.

In addition to the conventional CT equipment (e.g. reel and power pack), the surface system comprises the equipment to maintain a tensioned CT configuration, i.e. the heave compensation system. A derrick is necessary to handle the subsea equipment and the bottom-hole assembly (BHA). The subsea equipment packages located on deck are transported to and from the derrick via a skidding track. The equipment is installed by utilizing a heave compensated main winch. A cursor frame is also incorporated in the derrick, shown in Figure 26, to aid in controlling the equipment through the "splash zone".

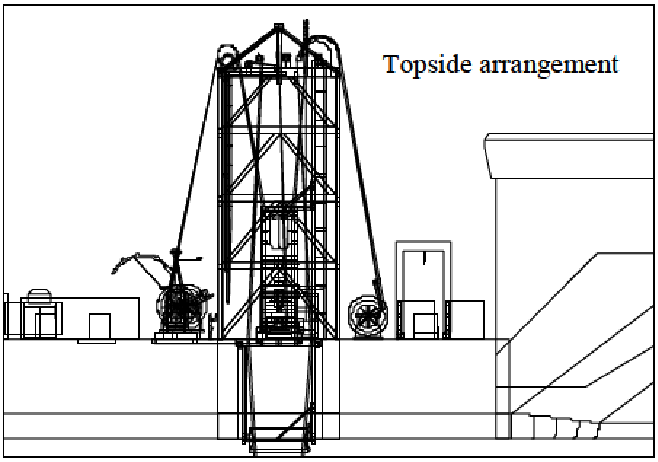


Figure 26 - RICTIS surface system [3]

The “splash zone” is the transition from water to air when lowering the equipment through the moonpool. Lowering equipment through the “splash zone” is a critical phase of the deployment. The equipment is prone to impacts from the vessel itself due to waves, and can lead to loss of equipment. If the vessel is located above a subsea structure, this can have disastrous consequences. After the subsea equipment is deployed, the BHA suspended in the moonpool and attached to the skid plates [3]. The gooseneck and the subsea injector are then placed on the cursor frame, prior to attaching the BHA to the CT. During the deployment/retrieval of the BHA in the lubricator, the cursor frame is using an active heave compensation system.

RICTIS’ subsea stack, shown in Figure 27, consists of a lubricator section, a subsea injector and well barrier packages. The subsea injector and the well control packages are run simultaneously, while the lubricator section is lowered in another run. When deploying the BHA, the lubricator top section is run together with the BHA. The top section includes a fixed stripper, a moveable stripper and a shear seal ram.

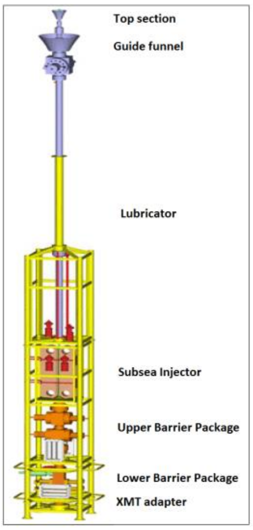


Figure 27 - RICTIS subsea stack [3]

At a first glance when looking at the RICTIS’ subsea stack in Figure 27 above, it appears as if the lubricator is fixed on top of the subsea injector. However, looking at the operational sequence shown in Figure 28 below, it is apparent that the lubricator actually goes through the subsea injector and connects to the upper barrier package during deployment of the BHA. The lubricator is able to go through the subsea injector by using extended retracts on the injector belts. This creates enough room for the lubricator to be lowered between the injector belts. After the BHA is deployed / lubricated into the well, the lubricator is moved to its upper position (on top of the subsea injector) and the belt retraction is reversed. The belts can now be engaged onto the CT string and running into hole can be initiated.

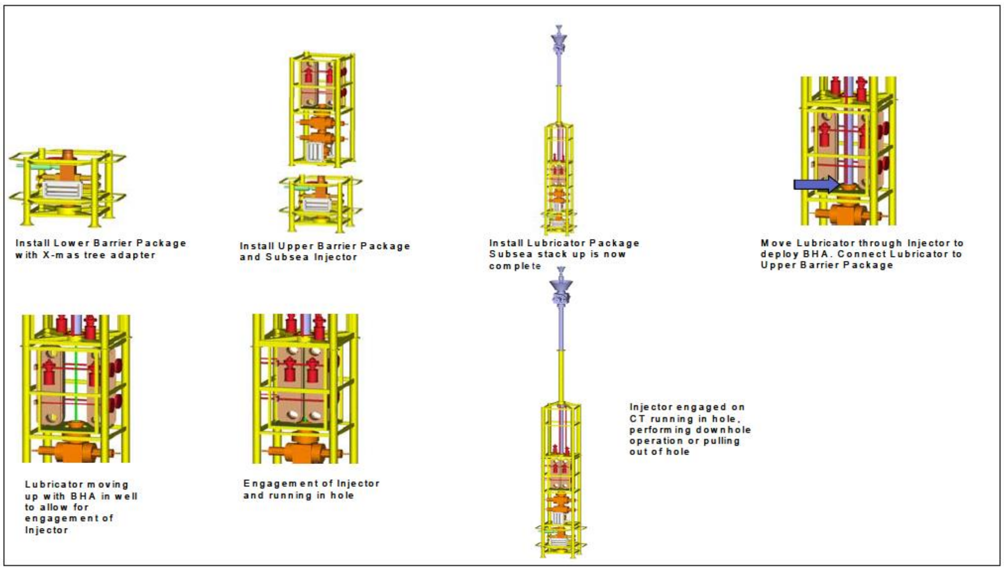


Figure 28 - RICTIS subsea stack and BHA operational sequence [3]

In Island Offshore Subsea’s OWCT system, the subsea injector is placed above the lubricator section. Since the outer diameter (OD) of the BHA is too large to go through a conventional injector, this implies that the subsea injector and the strippers must be run/pulled together with the BHA when entering/pulling out of hole. The RICTIS’ subsea stack setup eliminated the need to pull the subsea injector when pulling the BHA by placing the subsea injector below the lubricator section. This also has the advantage of reducing the bending moment on the XMT adapter. However, other challenges are encountered with this setup, which is elaborated on in the next section.

Essential to success of an OWCT system is the ability to avoid uncontrolled bending of the CT string. In other words; tension must be applied to the CT. This is especially important at the entry into lubricator. One challenge occurs when the BHA is installed in the lubricator pipe. The well is open, well pressures are sealed by the fixed stripper element in the lubricator top section and it is desired to lower the BHA into the well. Since the subsea injector is installed below the lubricator it cannot aid in lowering of the BHA. Sometimes the weight of the CT and the BHA itself may be sufficient to run the BHA further into the well. However, the problem arises when the weight is insufficient. While the BHA is located in the lubricator, and CT is fed from the injector at surface into sea, the CT string may curve or start to buckle. Figure 29 below is an illustration of this. This may result in only a small amount of force being exerted downwards on the BHA, and may not be sufficient to lower the BHA. In addition, the friction from the fixed stripper elements in the lubricator top section and the well pressure will be working against this force. Furthermore, the length of CT between vessel and subsea stack, are prone to the effect of currents. This may magnify the already induced curvature. Also, compared to a WL cable the area of the CT is considerably larger, and CT will therefore have increased hydrodynamic drag. If the CT is connected to both the surface and subsea injector, as it would be if the subsea injector was placed above the lubricator, the tension in the CT can be controlled. In this situation, the BHA has not yet reached the subsea injector and top tension can therefore not be applied.

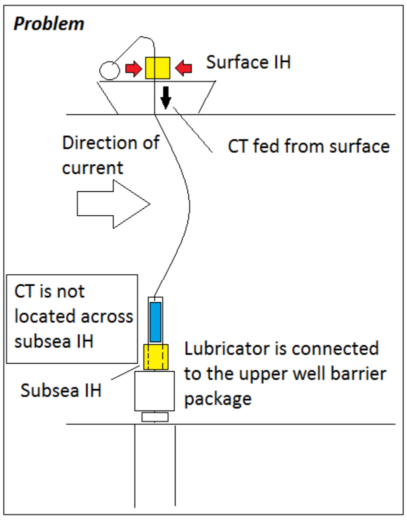


Figure 29 - Problem occuring during deployment of BHA

This problem was solved by implementing the moveable stripper. After the lubricator is pressure tested against the upper well barrier package and the fixed stripper in the lubricator top section, the gate valve in the upper barrier package can be pressure equalized and opened. The moveable stripper is then pumped down together with the BHA as shown in Figure 30 below, and the moveable stripper is then locked to the upper barrier package. The moveable stripper is now the highest point on the package. Since the moveable stripper is now serving as the primary barrier element against the well pressure, the lubricator can be detached and moved to its upper position. The injector belts are then retracted and engaged onto the CT string. Top tension can now be applied to the CT string.

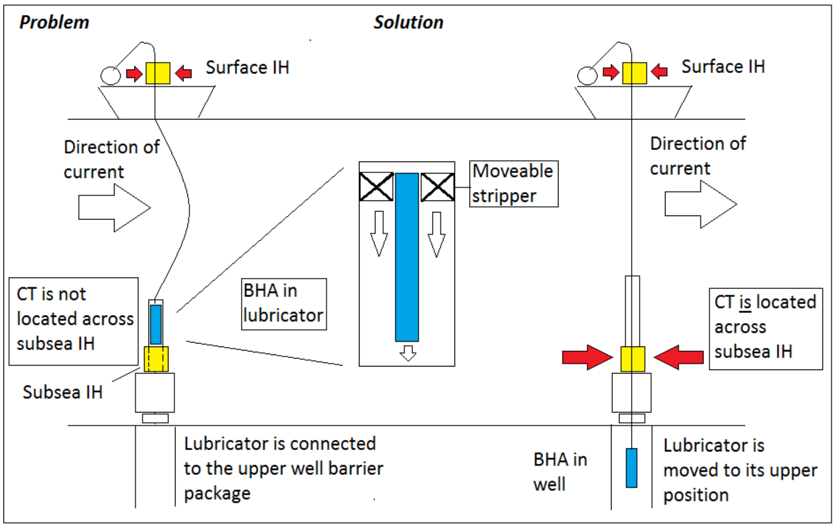


Figure 30 - Solution to problem during deployment of BHA

Comment: Performing operations on a subsea well is complex. It is hence reasonable to design the system with redundancy for the critical components of the system (e.g. what happens if the moveable stripper fails during an operation?). When performing operations on a subsea well, many unforeseen scenarios can occur, and the system should be able to handle scenarios that could occur within a pre-determined probability range.

Part II

10. Simulation program and method

10.1 Modelling

The OWCT models are made using Orcaflex. The models were originally designed in Orcaflex 10.0 by Sveinung Eriksrud in 4Subsea, but were later re-designed to fit Orcaflex 9.8b at the University of Stavanger by the same person. Sveinung built the initial models from data obtained from the writer of this thesis through Island Offshore Subsea. Assumptions were made where data was lacking. The models were adjusted several times by the author of this thesis before the final results were obtained from simulations. The model is presented in detail in chapter 11.

It is emphasized that the writer of this thesis did not construct the initial models in Orcaflex, but served as a provider of input data and boundary conditions. It should also be mentioned that corrections and adjustments made in the model was done by the author of this thesis.

10.2 Orcaflex

Orcaflex is a 3D non-linear time domain finite element analysis software for offshore systems and is developed by Orcina. The software allows the user to create a model of an offshore system, and further on to simulate a wide range of scenarios by varying parameters.

The software allows the user to construct an offshore model by using 6D buoys, 3D buoys, lines, components, vessels, winches and links. Environmental properties like wave height, wave spectrum and current speed are examples of parameters that are varied to simulate different scenarios.

Apart from time domain features, the software also allows for modal analysis (frequency domain) for the entire system or for single lines.

The target with the simulations is to obtain the systems global response and local strains and stresses. Orcaflex is mainly used to analyse riser systems, hose systems and installation scenarios etc. In this thesis however, the software is used to simulate the loads on a riserless/open water coiled tubing system. The following sections are entirely copied/based on the information provided in Orcina's website [30].

10.2.1 Orcaflex coordinate systems

Orcaflex uses one global coordinate system GXYZ, where G is the global origin and GX, GY and GZ are the global axes directions. In addition, there are a number of local coordinate systems (LXYZ), generally one for each object in the model. Notation is tied to Figure 31 below.

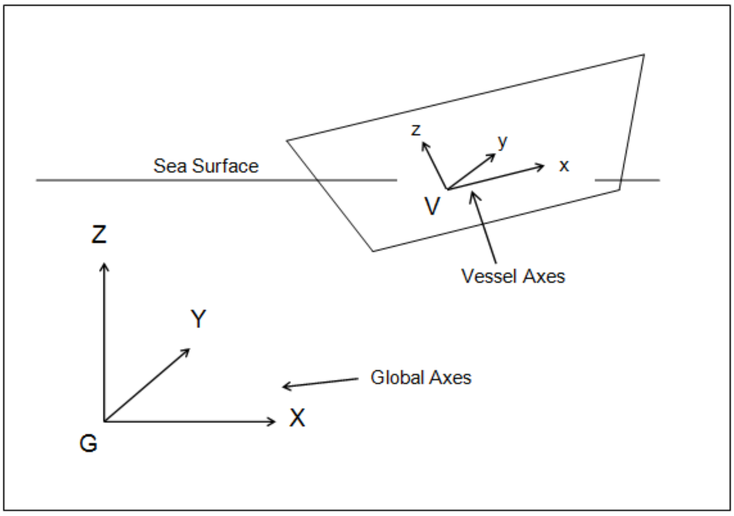


Figure 31 - Orcaflex coordinate systems

Directions and headings are specified in Orcaflex by giving the azimuth angle of the direction, in degrees, measured positive from the X-axis towards the Y-axis, as shown in Figure 32 below.

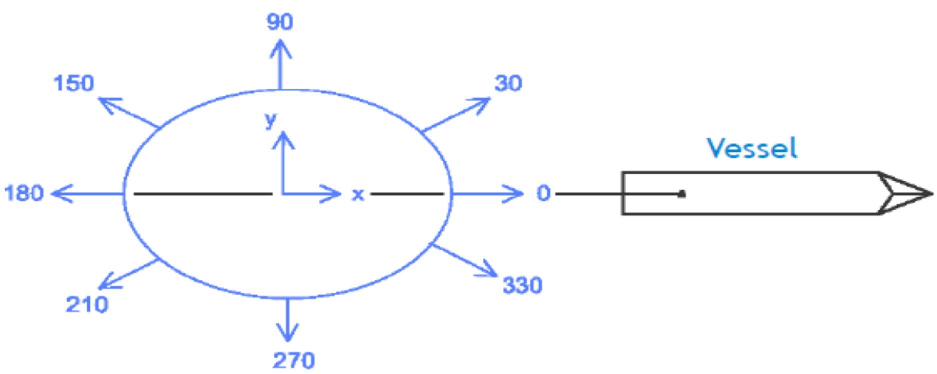


Figure 32 - Direction specification

10.2.2 Orcaflex line model

The line model used in Orcaflex is illustrated in Figure 33 below.

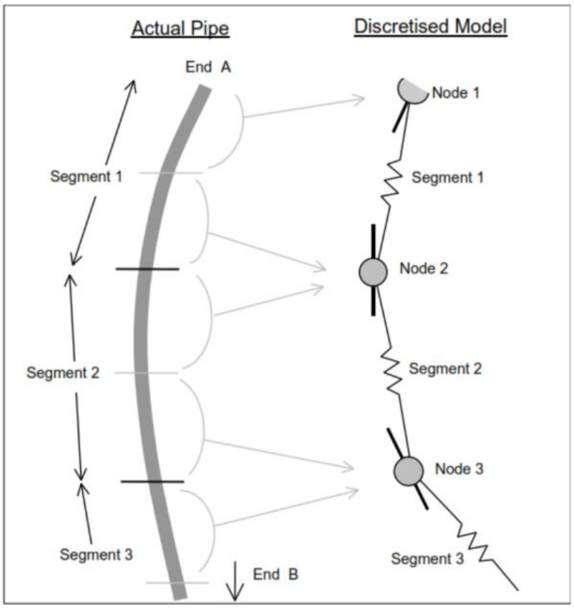


Figure 33 - Orcaflex line model

"*The line is divided into a series of line segments which are then modelled by straight massless model segments with a node at each end. The model segments only model the axial and torsional properties of the line. The other properties (mass, weight, buoyancy etc.) are all lumped to the nodes, as indicated by the arrows in the figure above."* [30]

10.2.3 Static analysis

There are two objectives for a static analysis:

- To determine the equilibrium configuration of the system under weight, buoyancy, hydrodynamic drag etc.
- To provide a starting configuration for dynamic simulation.

Static equilibrium is determined in a series of iterative stages:

1. At the start of the calculation, the initial positions of the vessels and buoys are defined by the data: these in turn define the initial positions of the ends of any lines connected to them.

2. The equilibrium configuration for each line is then calculated, with the line ends fixed.
3. The out of balance load acting on each free body (node, buoy, etc.) is then calculated and a new position for the body is estimated. The process is repeated until the out of balance load on each free body is zero (up to the specified tolerance).

10.2.4 Dynamic analysis

Orcaflex implements two complementary time domain dynamic integration schemes, explicit and implicit. The dynamic simulations in this thesis will be performed using the implicit integration scheme. The reader is referred to Orcina's website [30] for more specification.

The equation of motion which Orcaflex solves is as follows:

$$M(p,a) + C(p,v) + K(p) = F(p,v,t)$$

where

M(p,a) is the system inertia load.

C(p,v) is the system damping load.

K(p) is the system stiffness load.

F(p,v,t) is the external load.

p, v and a are the position, velocity and acceleration vectors respectively.

t is the simulation time.

Both schemes re-compute the system geometry at every time step and so the simulation takes full account of all geometric nonlinearities, including the spatial variation of both wave loads and contact loads.

Referring to Figure 34 below; before the main simulation stage(s) there is a build-up stage, during which the wave and vessel motions are smoothly ramped up from zero to their full size. Ramping of current is optional. This gives a gentle start to the simulation and helps reduce the transients that are generated by the change from the static position to full dynamic motion. This build-up stage is numbered 0 and its length should normally be set to at least one wave period. The remaining stages, simply numbered 1, 2, 3, … are intended as the main stages of the analysis.

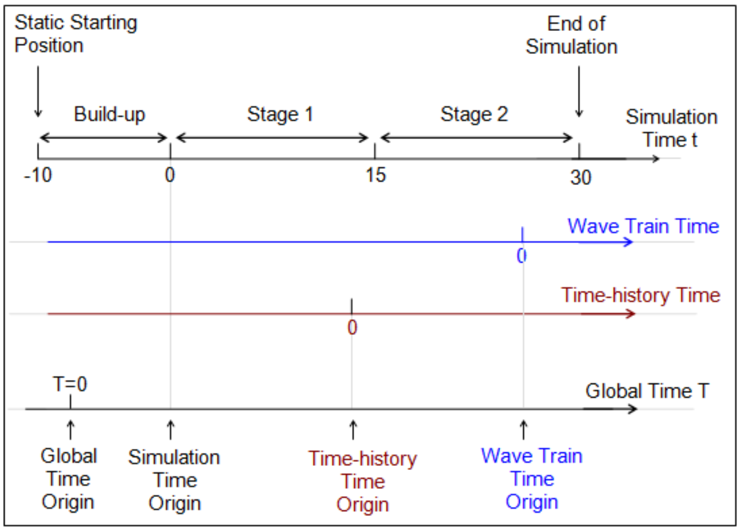


Figure 34 - Stages

For more specifications in how Orcaflex calculates the statics and the dynamics, the reader is referred to Orcina's website [30].

To create a model that could be representative for an actual system, several input parameter values must be inserted into Orcaflex. The following sections will provide an overview of these input parameters.

11. OWCT model

11.1 Geometry

A sketch of the system is made to demonstrate the basic geometry of the model in Orcaflex. Figure 35 is a geometric model based on Figure 3 in the system description. The figure is a modified version of a figure obtained from API 17G [7]. It was modified by implementing a new parameter, Y, which represents the length of the subsea stack. In operations using a WOR, the length of the subsea stack is often quite short. For the modelled system in this thesis, the stick-up of the subsea stack (including the XMT and the wellhead) is approximately 46m. In shallow waters, this is a considerable length, and should not be neglected.

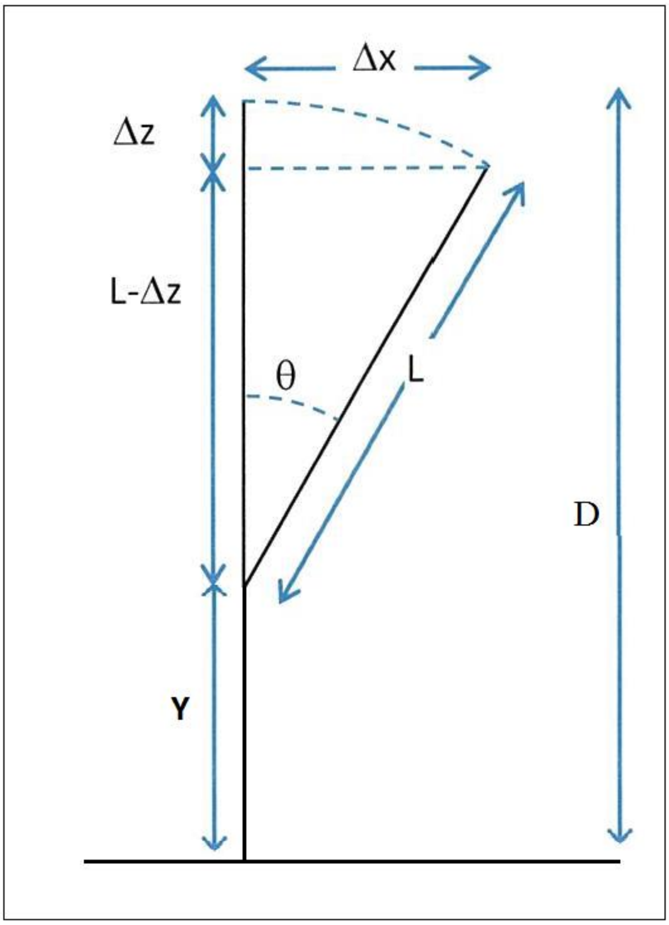


Figure 35 - Geometry nomenclature

The vessel offset is represented by ΔX, whereas the required stroke capacity to avoid stroke-out is denoted ΔZ. The water depth plus the distance from mean sea level

(MSL) to the topside injector is denoted D. The length, L, of CT between vessel and subsea stack is thus given by:

$$L = D - Y$$

whereas ΔZ is given by:

$$\Delta \mathrm{Z} = \mathrm{L} - \sqrt{L^2 - \Delta \mathrm{X}^2}$$

The stroke capacity of the PHC is assumed to be 7m, whereas the AHC (main winch) stroke capacity is 5m. However, the AHC is not position controlled, and can thus not be included. By only using the PHC with a stroke capacity of 7m, it gives a ΔZ equal to 3,5m if at mid-stroke (centered position).

Considering a water depth of 100m and distance from MSL to topside injector equal to 13m, D becomes:

$$D_{WD=100m} = 100m + 13m = 113m$$

The length, L, of CT in a water depth of 100m, considering a stick-up length of 46m is then:

$$L_{WD=100m} = D_{WD=100m} - Y = 113m - 46m = 67m$$

For a water depth of 300m:

$$D_{WD=300m} = 300m + 13m = 313m$$

$$L_{WD=300m} = D_{WD=300m} - Y = 313m - 46m = 267m$$

The remaining compensator stroke, ΔZ, as a function of offset for both water depths is displayed in Figure 36. It is assumed that the entire stroke length is used, i.e. no safety margin is included and no stroke is used for vessel heave.

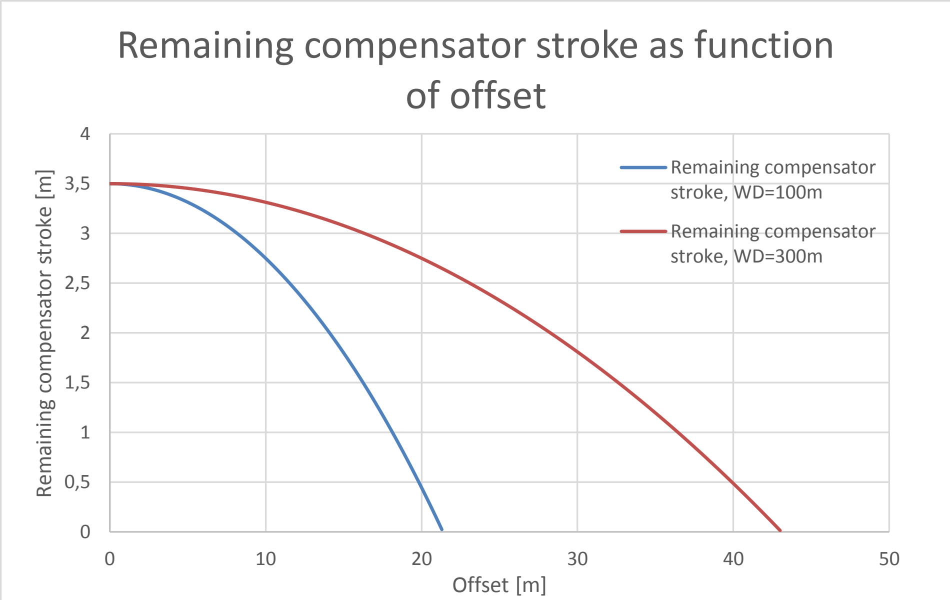


Figure 36 - Remaining compensator stroke as a function of offset

Maximum offset before stroke-out will occur:

- In 100m WD: $\Delta X_{max} \approx 21{,}3m$
- In 300m WD: $\Delta X_{max} \approx 43m$

Since the heave compensation stroke limits not are present in the models, the above calculations were necessary to get an indication of when a stroke-out would occur. A more detailed analysis should be done here by including the effects explained in section 6.2.2.

The maximum offset of vessel position in the simulations will be 10%MSL, i.e. 10m and 30m for 100m WD and 300m WD, respectively. Seeing that the offset angle (θ) would not be the same for the two water depths, this could play a significant role for the CT loads. The value for the angle is dependent on the difference in length between the water depth and the subsea stack stick-up. With a length of 46m, the subsea stack stack-up makes up 46% of the water depth in 100m WD, while only 15,3% in 300m WD. The maximum angle (static conditions) is calculated using the following equation:

$$\theta = \tan^{-1}\left(\frac{\Delta x}{L}\right)$$

With values:

$$\theta_{100m\,WD} = \tan^{-1}\left(\frac{10m}{67m}\right) \approx 8{,}5°$$

$$\theta_{300m\,WD} = \tan^{-1}\left(\frac{30m}{267m}\right) \approx 6{,}4°$$

The offset angle is considerably less in 300m WD.

11.1 Field relevance

Two models are made; one with 100m WD and one with 300m WD. 100m WD is similar to that of the Mariner and Bressay fields on the UKCS, while 300m WD is similar to that of the Åsgard field on the NCS. Both are hence North Sea relevant water depths. Simulations with ocean current will only be done for the 100m-model. A 1-year current from the Mariner and Bressay fields will thus be used in these simulations.

Comment: Mariner and Bressay fields do not have subsea wells. Gullfaks, Statfjord and Johan Sverdrup are examples of fields on the NCS that has subsea wells in a water depth of approximately 100m.

11.2 Orcaflex model

A CT string will extend from the vessel down to the subsea stack. An axial load downwards have been applied to the SSI to account for the weight of CT in well. Top tension will be applied in the PHC such that the entire CT string will have positive effective tension between the vessel and the subsea stack. A passive heave compensator will hold the topside injector with associated CT string stationary relative to the well. The PHC stiffness is in reality 11% (in IOSS's OWCT system), but the PHC tension variation vs. stroke is not included in this thesis. The CT bending cycles occurring from the reel and over the gooseneck has not been modelled, and will be the most obvious limitation for accurate CT load estimates.

The model of the OWCT system in 100m WD is seen in Figure 37 below. The model as seen from above is shown in Figure 38. Model properties will be presented in the following sections. The model can, for the sake of the presentation, be divided into four parts:

- Vessel data
- Topside equipment
- Subsea Stack
- The coiled tubing

Important note: No limits such as allowable stresses etc. have been added to the model. This was handled as a post-processing matter.

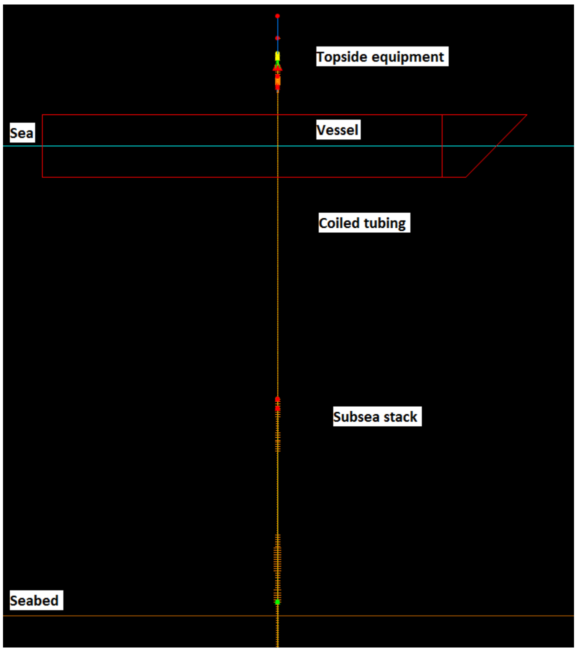


Figure 37 - Orcaflex OWCT model

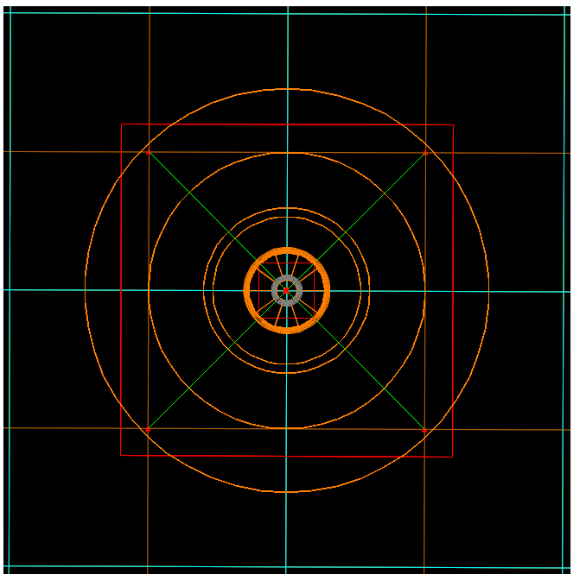


Figure 38 - Model seen from above

11.3 Vessel data

Figure 39 - Island Constructor

Island Constructor, shown in Figure 39, will be used as the vessel in all simulations. Constructor has a length of 120,5m and a width of 25m. The moonpool size is 8m x 8m, this is however not modelled, i.e. this boundary condition is not present in the model. The reader is referred to Island Offshore's website for more information [31].

A vessels motion is described using the six degrees of freedom shown in Figure 40 below. The linear motions are described by:

- Heave: vertical up- and down motion
- Sway: lateral side to side (port to starboard) motion
- Surge: longitudinal front to back (bow to stern) motion

The rotational motions are described by:

- Pitch: rotation about Y-axis
- Roll: rotation about X-axis
- Yaw: rotation about Z-axis

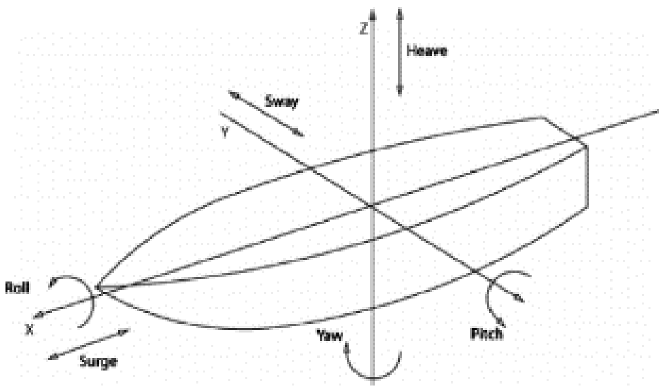


Figure 40 - A vessels six degrees of freedom

Response Amplitude Operators (RAO) determines how a vessel responds to waves in the vessel's 6 degrees of freedom. An RAO is a statistical analysis obtained through testing a model of a proposed ship design in a model basin, or from running specialized computational fluid dynamic computer programs [32]. For regular waves, it is the ratio of a vessel's motion to the wave amplitude causing that motion and presented over a range of wave periods [33]. The RAO's for Constructor used in Orcaflex was acquired by Island Offshore Subsea. Figure 41 and Figure 42 below shows the RAO's for Constructor. Figure 41 shows response amplitude plotted against wave period and Figure 42 shows phase plotted against wave period, both for all six degrees of freedom. The RAO direction in the figures below is 180 degrees, which will be case when waves propagate towards the bow of the vessel. It is thus seen that the vessel will not have sway, roll and yaw response.

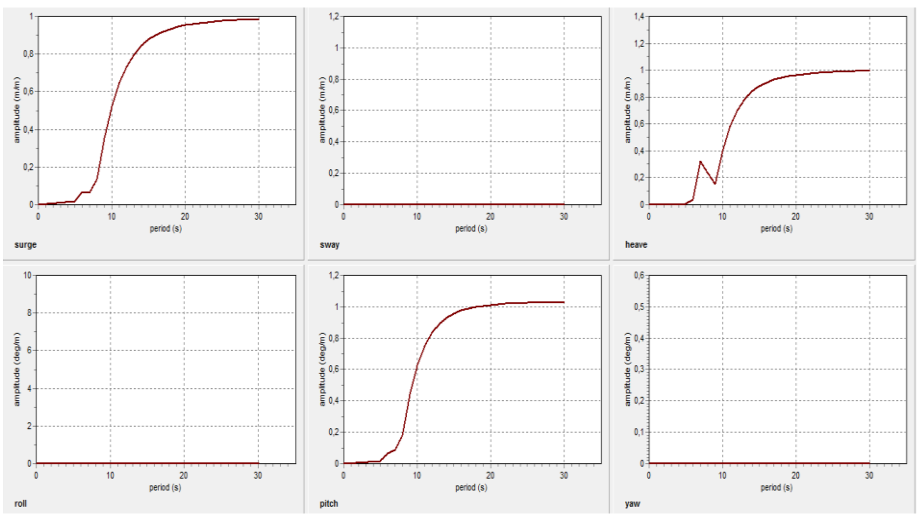


Figure 41 – Displacement RAO – amplitude vs. period (direction: 180 degrees)

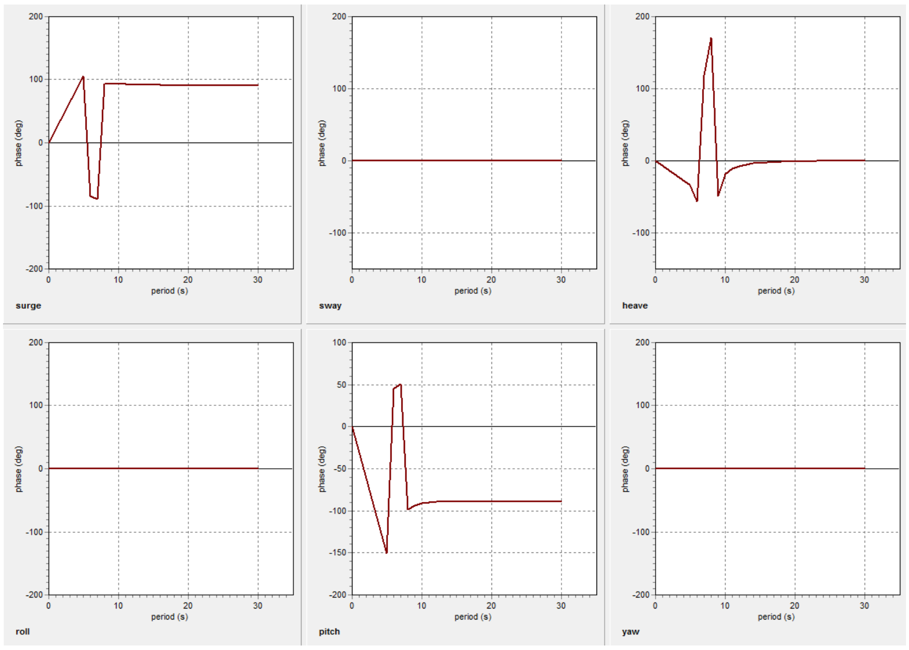


Figure 42 - Displacement RAO – phase vs. period (direction: 180 degrees)

RAO origin is shown in Table 3.

Table 3 - RAO origin

x	y	z
0	0	-3,897

11.4 Topside equipment

The topside equipment in the models consists of:

- A passive heave compensator with associated winch wire,
- a topside/surface injector (TSI) attached to a
- Lower Cursor Frame (LCF)
- and a guide funnel/bellmouth

The model (on the left hand side) is based on the rightmost sketch in Figure 43 below. The sketch was obtained from IOSS. The funnel was not present on the sketch, and was added to the model at a later stage by the author of this thesis. The reel, the gooseneck and the CT extending from the reel, over the gooseneck and into the TSI has not been included in the model. This is because it does not play a role in the structural loads in CT in open water, but has to do with fatigue, which is a typical post-processing matter. This will require an analysis on its own.

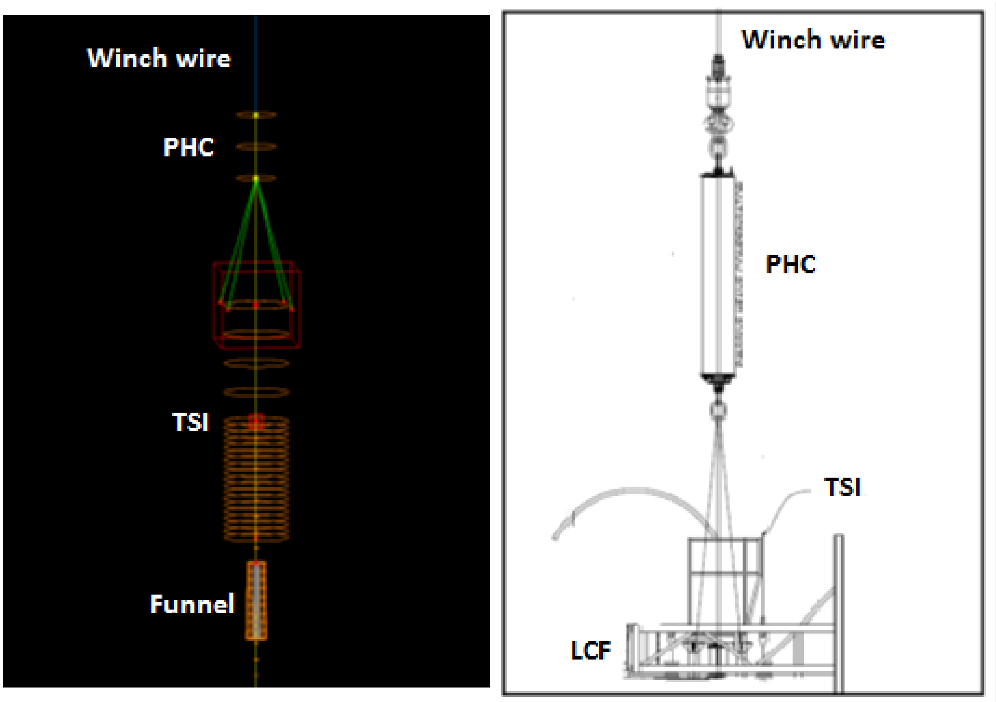


Figure 43 – Model and sketch of the OWCT topside equipment

The winch wire provides a way of modelling constant tension. In Orcaflex, a winch is a massless connection between two or more points, but in this case it is connected to the PHC in the lower end and to Island Constructor in the upper end.

The applied tension in the winch wire can be specified, and is for later reference referred to as "specified tension in the PHC".

Four links are then used to connect the PHC to the LCF. The LCF is modelled as a beam element with no axial stiffness, but with lateral constraints, i.e. very high bending stiffness, allowing the TSI to move vertically to the vessel only. For modelling purposes, the mass of the LCF is added to the TSI.

The distance from bottom of the TSI relative to the sea is 13m, as illustrated in Figure 44.

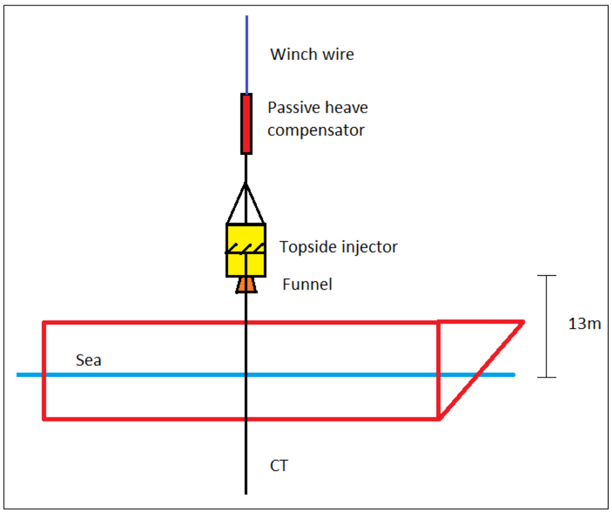


Figure 44 - Illustration of topside equipment

After studying the history of OWCT, it was seen that a funnel often were present in the concepts (RICTIS, IOSS). It was thus decided to include a funnel in the models to check potential effects. The funnel dimensions was based on information obtained from IOSS, but had to be modified somewhat in order to be modelled correctly in Orcaflex. The modelled funnel should give a good representation, given that the funnel properties are correctly obtained from IOSS. Figure 45 displays the funnel as modelled in Orcaflex. It is modelled as a weightless elastic solid, which is used to model physical obstacles. The funnel is directly connected to the TSI, which means that the CT will enter the funnel as soon as it leaves the TSI.

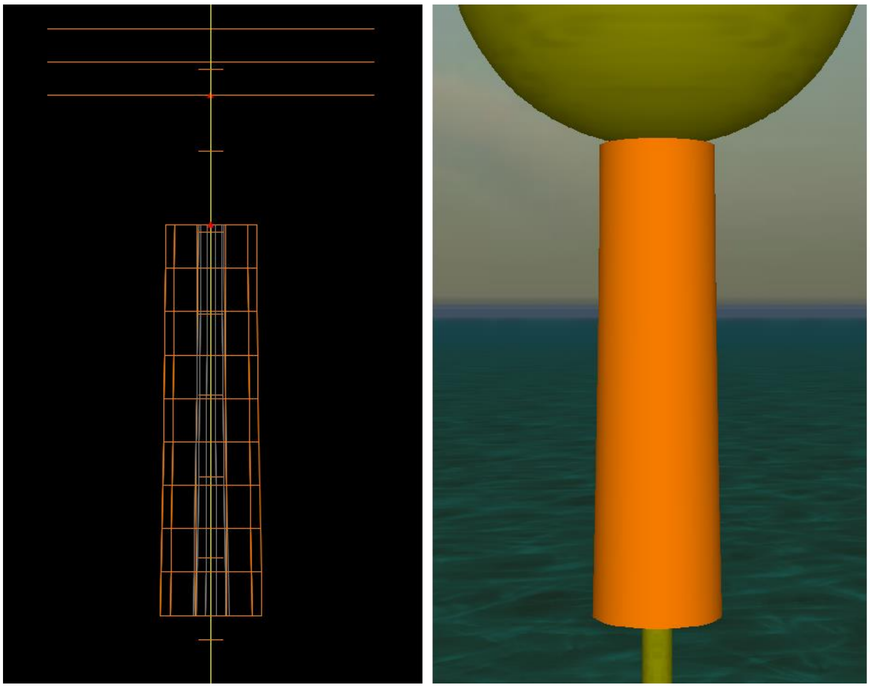


Figure 45 - Funnel as modelled in Orcaflex

11.4.1 Topside equipment properties

Table 4 displays weight- and structural properties for the TSI.

Table 4 - Properties of topside equipment

Component	Length	Dry steel weight empty	Sub. Steel weight SW filled	OD main pipe	ID main pipe
[-]	[m]	[kg]	[kg]	[m]	[m]
Topside injector	3,658	15000,0	13050,0	1,000	0,075

Before the funnel could be modelled, the radius of curvature had to be established from information provided in Table 5. The wall thickness of the funnel was set to a constant equal to 0,1m, and has no effect on the calculation. Figure 46 illustrates the funnel nomenclature used for calculation.

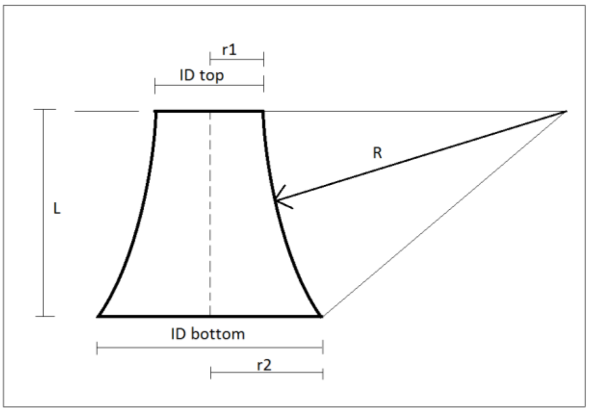
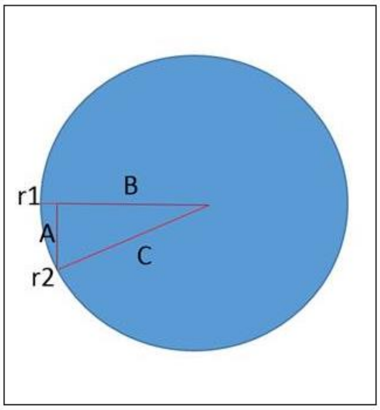


Figure 46 - Funnel sketch

Table 5 - Funnel properties

	[in]	[m]
ID top	2,95	0,07493
r1	1,475	0,037465
ID bottom	4,4	0,11176
r2	2,2	0,05588
L		1,7
Thickness		0,1

The radius of curvature of the funnel is given as follows:



where

- r1 = inner radius; at top of funnel
- r2 = inner radius; at bottom of funnel
- A = length of funnel (L)
- C = radius of circle (R)

Radius (C) on circle:

$C = \sqrt{A^2 + B^2}$

where B is given as:

$B = C - (r2 - r1)$

By combining the two equations above the following can be obtained:

$C = \frac{A^2+(r2-r1)^2}{2*(r2-r1)} = 78{,}4778472m \approx 78{,}48m$

$$R_{funnel} \approx 78{,}48m$$

Compared to a gooseneck, which usually has a radius typically ranging from approximately 1,8 to 3m (72-120inches), the funnel’s curvature (1/R) is significantly less.

When the radius of curvature was established, the inner diameter/radius along the funnel could be established. Table 6, which is plotted into Orcaflex, shows the inner diameter of the funnel from top to bottom along the Z-axis. Orcaflex uses linear interpolation between the points. The wall thickness is, as mentioned previously, set to a constant equal to 0,1m.

Table 6 – Inner diameter/radius of funnel along Z-axis

Distance [m]	Inner diameter [m]	Inner radius [m]
0	0,07493	0,037465
0,1	0,075058	0,037529
0,2	0,07544	0,03772
0,3	0,076076	0,038038
0,4	0,076968	0,038484
0,5	0,078116	0,039058
0,6	0,079518	0,039759
0,7	0,081174	0,040587
0,8	0,083086	0,041543
0,9	0,085252	0,042626
1	0,087672	0,043836
1,1	0,09035	0,045175
1,2	0,09328	0,04664
1,3	0,096466	0,048233
1,4	0,099908	0,049954
1,5	0,103604	0,051802
1,6	0,107554	0,053777
1,7	0,11176	0,05588

R_{funnel} is now established. A hand-calculation was then performed to get an indication on if the CT could withstand being curved along the entire length of the funnel. Considering a CT going over a gooseneck, it will almost only experience bending (minor tension). A CT going through a funnel will in addition be applied a tension, but this is not considered in these calculations. Calculation of utilization is explained in chapter 13.

By assuming a CT material yield strength of 90000 psi and the CT properties in Table 9, the maximum allowed bending moment in the CT was calculated as:

$$M_{max} = \frac{\sigma_y * I}{y} = \frac{\sigma_y * \frac{\pi}{64}(OD^4 - ID^4)}{\frac{OD}{2}}$$

where

σ_y is the material yield strength of the CT;

I is the second moment of inertia;

y is the distance to neutral axis.

With inserted values the max allowed bending moment was:

M_{max} = 10,16kNm

The relationship between curvature and bending moment is given by:

$$\frac{1}{R_{min}} = \frac{d^2y}{dx^2} = \frac{M_{max}}{E * I}$$

where E is the Young's Modulus. By rearranging the above equation the minimum allowed radius of curvature, R_{min}, to avoid yielding of the CT is calculated:

$$R_{min} = \frac{E * I}{M_{max}} = \frac{2{,}06 * 10^{11} Pa * 5{,}97 * 10^{-7} m^4}{10{,}16 * 10^3 N} = 12{,}1m$$

Seeing that

$$R_{min} = 12{,}1m \; < \; R_{funnel} = 78{,}48m$$

gives an indication on that the CT will <u>not</u> yield by following the curvature of the funnel due to bending alone. There will of course be an effective tension present in the CT that must be accounted for in terms of utilization. Favourably, a subsea injector will be present to carry the weight of a long CT in the well. This means that the effective tension in CT going through the funnel is controlled during the entire operation, except in case of an accident.

11.5 The subsea stack

The subsea stack is based on a sketch obtained from IOSS. The true subsea stack is a rather complex structure. The model will thus be a simplified version, which among other things, implies that the components will be modelled as tubular shapes with approximate structural and hydrodynamic properties.

The subsea stack will be fixed to the XMT fixed to the wellhead which in turn is fixed to the seabed.The components of the subsea stack are illustrated below in Figure 47. The subsea stack (from top to bottom) residing on the X-mas tree (XMT) and wellhead (WH) consists of:

- Subsea injector (SSI)
- Strippers
- CT BOP
- Upper lubricator package (ULP)
- Lubricator pipe
- Lower lubricator package (LLP)
- Well control package (WCP)
- Safety head

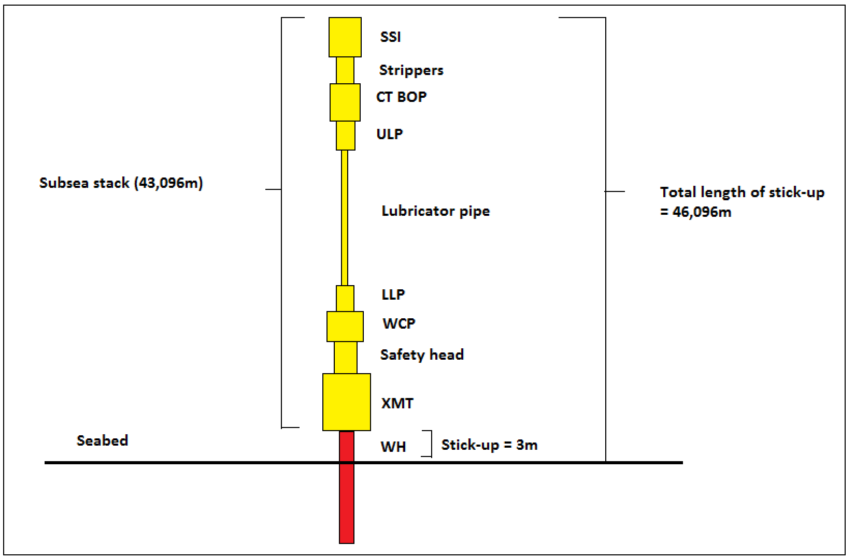


Figure 47 – Sketch of OWCT subsea stack used in the model

It is important to note that the total length of the stick-up from seabed is equal to the length of the subsea stack including the XMT plus the wellhead stick-up. The subsea stack including XMT is 43,096m long and the wellhead stick-up is 3m, thus the total length of the stick-up is 46,096m. In a water depth of 100m, this means that there is only ~54m from MSL down to top of the subsea stack. Figure 48 displays the subsea stack as modelled.

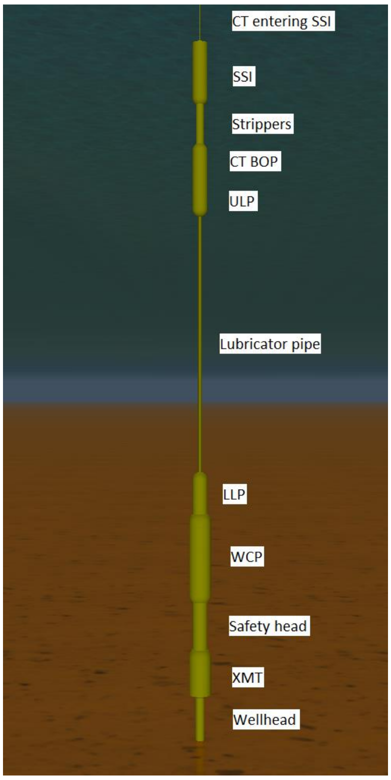


Figure 48 - Subsea stack and wellhead as modelled in Orcaflex

11.5.1 Subsea stack and wellhead properties

The lubricator section is modelled in two parts (upper and lower). This is done to take the accumulators that is usually a part of the lower tubular into account. This does not affect the bending stiffness of the pipe, but gives more accurate model behaviour with regards to hydrodynamic properties. Since some of the components have a square shape in reality, and Orcaflex models the components as cylindrical shapes, the properties must be manipulated in order to obtain more accurate geometrical properties. This is called equivalent system modelling. The properties of a component are combined to an equivalent pipe. This modelling technique is often used to make the model properties applicable to the calculation methods in the software. Hence, the structural properties presented here may hence not necessarily be the properties plotted into Orcaflex. The manipulated properties were calculated in a separate Excel-sheet provided by 4Subsea by the author of this thesis (due to nomenclature confusion this was decided to not be included in the appendix). The presented properties in this section are the original properties.

The normal stiffness in the TSI, SSI and funnel was set to 100*E6 kN/m/m^2. This is not a realistic value, but was necessary to model contact between the CT and the components. It does not affect the results.

The dimension and properties of the subsea stack and the wellhead can be seen below in **Error! Reference source not found.** and Table 8.

Table 7 - Subsea stack and wellhead properties

Component	Length	Dry steel weight empty	Sub. Steel weight SW filled	OD main pipe	ID main pipe
[-]	[m]	[kg]	[kg]	[m]	[m]
Wellhead	21,000	1 000,0	870,0	0,600	0,300
Safety head	4,171	1 000,0	870,0	1,000	0,180
XMT	2,500	30 000,0	27 000,0	1,460	0,460
WCP	4,768	18 000,0	15 000,0	1,460	0,460
LLP	2,803	5 000,0	4 350,0	1,000	0,180
Lubricator tubular (lower)	8,930	2 000,0	1 740,0	0,273	0,180
Lubricator tubular (upper)	8,930	1 700,0	1 479,0	0,273	0,180
ULP	2,364	1 000,0	870,0	1,000	0,180
CT BOP	1,500	1 000,0	870,0	1,000	0,180
Strippers	3,472	1 000,0	870,0	0,533	0,180
Subsea injector	3,658	7 000,0	6 090,0	1,000	0,075

Added mass and drag coefficients are shown below in Table 8. Inertia coefficients (Cm) are calculated in Orcaflex as Cm = Ca +1 unless stated otherwise. Remember that the coefficients have been altered in the equivalent system model.

Table 8 - Coefficients

Component	Added mass coefficent (x), Ca	Drag coeffcient, (x) Cd
Wellhead	1,00	1,00
XMT	1,00	2,00
Safety head	1,00	2,00
WCP	1,00	2,00
LLP	1,00	2,00
Lubricator tubular (lower)	1,00	2,00
Lubricator tubular (upper)	1,00	1,00
ULP	1,00	1,00
CT BOP	1,00	2,00
Strippers	1,00	2,00
Subsea injector	1,00	2,00

Comment to Table 8: Hydrodynamic properties of complex geometry require model testing. The values in the table above are simplified.

The SSI is applied a load of 100kN in negative Z-direction (local coordinate system for the SSI) to account for the weight of CT in well. In reality, the weight in the SSI will naturally vary depending on the length of CT in well. The applied load is distributed as compression throughout the subsea stack. The CT that, in reality, would be suspended from the SSI is hence not present in the model. The applied load is present in all simulations.

11.6 The coiled tubing

This section presents the input data for the CT used in the model. Material properties, geometric dimensions and connection stiffness are parameters that are defined prior to the simulations.

11.6.1 Boundary Conditions

The CT will be modelled as a homogenous steel pipe. The CT is modelled as fixed to the middle of the TSI and the SSI as shown in Figure 49 below (funnel below TSI is not included in the figure). No moonpool is present in the model. The only boundary conditions for the CT on topside will hence be the geometrical and structural properties of the TSI and the funnel.

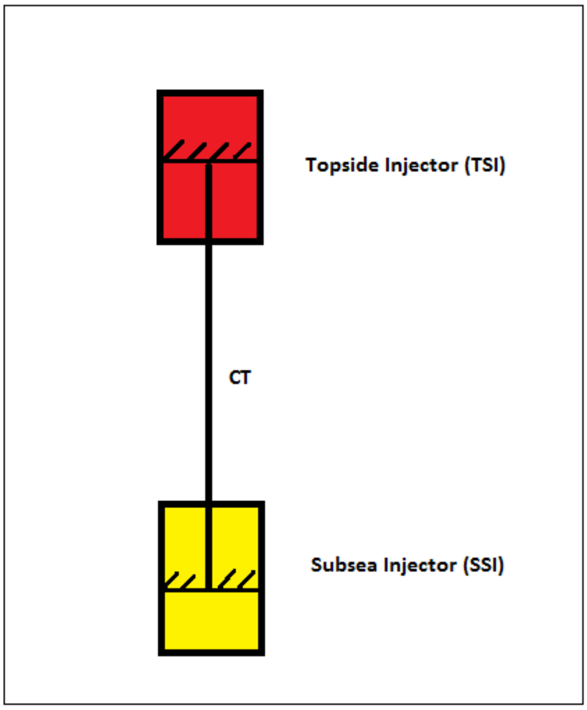


Figure 49 - Modelling of CT

The top tension in CT is applied through the TSI determined by the applied tension in the winch wire, i.e. the specified tension in the passive heave compensator (PHC). The PHC will be active during all simulations, and will thus keep the effective tension in the CT constant (there will be variations due to the dynamic motions).

11.6.2 CT input data

The CT used in the model was given the same dimensions as the CT that was used when IOSS performed OWCT drilling on the Butch field in 2015. The added mass,

inertia and drag coefficients are simplified assumptions. The CT input data are shown in
Table 9.

Table 9 - CT properties

Outer diameter (OD)	2,875 in	0,073025m
Inner diameter (ID)	2,5 in	0,0635m
Thickness (t)	0,188 in	0,0048m
Added mass coefficient	1,0	
Inertia Coefficient	2,0	
Drag coefficient	1,0	
Weight		8,038kg/m

With reference to Figure 33, a line is defined with a series of segments. The CT is modelled with a constant segment length of 0,25m.

11.7 Environmental data

11.7.1 Water depth

Simulations in 100m and 300m water depth are performed.

11.7.2 Current

A 1-year current profile from the Mariner and Bressay fields on the UKCS are used in the simulations with 100m water depth [34]. The current profile is estimated to have an annual probability of exceedance of 0.63. The omnidirectional current profile is shown in Figure 50. Current is not present for simulations in 300m WD, due to lack of time.

Water depth [m]	Current speed [cm/s]
0	80
-10	80
-20	77
-30	70
-40	62
-60	60
-80	55
-97	50
-100	0

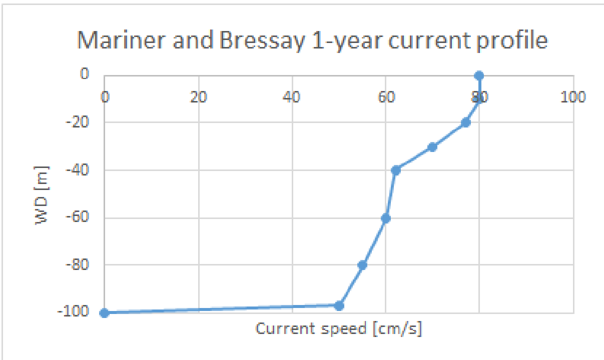


Figure 50 - Mariner and Bressay 1-year current profile

11.7.3 Wave spectrum

Orcaflex allows the user to choose between different wave spectrums, for both regular and irregular waves. A regular wave is a single wave component defined by wave direction, height and period. Airy, Dean, Stokes 5th or Cnoidal are different wave theories for regular waves. The Airy (single) wave theory (often referred to as linear wave theory) with wheeler stretching is chosen for all simulations with waves.

Orcina [30] explains kinematic stretching as "*the process of extending linear Airy wave theory to provide predictions of fluid velocity and acceleration at points above the mean water level. It only applies to Airy waves and to random waves (which are made up of a number of Airy waves).*"

"Linear wave theory in principle only applies to very small waves, so it does not predict kinematics for points above the mean water level since they are not in the

fluid. The theory therefore needs to be "stretched" to cover such points, and Orcaflex offers a choice of three published methods": there among Wheeler Stretching. "*This method stretches (or compresses) the water column linearly into a height equivalent to the mean water depth."*

When the wave height and wave period are defined using the Airy linear wave theory, properties are applied for all waves. Hence, the terms "significant wave height" and "peak period" does not apply.

11.7.4 Wave settings

A wave setting example can be seen in Figure 51. Wave direction, height and period can be varied depending on which sea state that is to be simulated.

Data for Wave Train: Wave1

Wave Data:

Direction (deg)	Height (m)	Period (s)	Wave Origin X (m)	Wave Origin Y (m)	Wave Time Origin (s)	Wave Type
180,00	7,00	12,00	0,00	0,00	0,000	Airy

Figure 51 - Wave settings

12 Load cases

Each load case contains parameter- and offset specifications. In a load case, all simulations are run with the associated offset specifications. The offset is specified as a primary motion in a time history file that defines the vessel Primary X, Primary Y, Primary Z, Primary Rotation 1, Primary Rotation 2 and Primary Rotation 3 as a function of time. Displacement RAOs and harmonic motions are included in simulations with waves. All simulations with offset are performed with motion in the positive X-direction, i.e. Primary X. The time history files are thus presented accordingly.
Table 10 presents a general overview of the load cases.

Table 10 - Overview of load cases

Load case #	Type	Current	Waves	Water depth [m]	Specified tension in PHC [kN]	Funnel	Offset [m]	Comment
1	Static	No	N/A	100	160-620	Yes	0-10	Sensitivity analysis: no funnel present with specified tension in PHC equal to 240kN
2	Dynamic	No	Hmax / T	100	240	Yes	5	
3	Static	Yes	N/A	100	240	Yes	0-10	
4	Static	No	N/A	300	175-615	Yes	0-30	
5	Dynamic	No	Hmax / T	300	255	Yes	15	255kN in 300m WD gives the same effective tension in CT at SSI as 240kN in 100m WD

Each load case will be presented in the next sections, with associated:

- Objective
- Offset specifications
- Strategy

The strategy part will introduce the reader to the background for the chosen parameters to be simulated with. Modal analysis is as an example included here.

Parameters to be varied are wave height, wave period, current speed, current direction, wave direction and specified tension in the passive heave compensator (applied top tension).

Abbreviations in the tables associated with each load case:

H = wave height

T = wave period

CS = current speed

CD = current direction

WD = wave direction

ST = specified tension in passive heave compensator

12.1 Load cases in 100m WD

12.1.1 Load case #1

Objective:

The primary objective with load case #1 was to investigate the effect of varying applied tension on system loads in an accidental loss of position. Both the CT string and the subsea stack are of interest. Since the specified tension in the PHC is constant during an offset (provided it has sufficient stroke capacity), it is expected that the bending moment in the CT string will govern the increase in utilization. It is desired to check how the bending moment will change by varying the applied top tension. The lubricator section is the most slender component in the subsea stack, and is believed to experience the highest bending stress. By obtaining the loads in the system, it is possible to determine the utilization of structural capacity at the most critical points. It would thus be pertinent to establish an operational envelope displaying the capacity utilization of critical points in relation to the vessel's offset and the specified tension in the PHC.

A sensitivity analysis was performed as a secondary objective to investigate whether the funnel had an effect on the bending moment in the CT. The specified tension in PHC was then set to 240kN. Associated effective tension in the CT string can be found in Appendix B.

Offset specifications:

Offset specifications are presented in Table 11:

Table 11 - Time history file for load case #1

Stage	Time [s]	Primary X [m]
Build-up	-1,00	0,00
Stage 1	1000,00	10,00

A quasi-static approach has been used to simulate the offset. This is a modelling technique used to avoid performing multiple static simulations. Since no waves or current will be present during these simulations, the build-up time is set to only 1s. This will provide enough time to avoid system transients occurring during the analysed stage (Stage 1). An offset of 10m was simulated linearly over 1000s. By simulating the offset slowly, the system is allowed to reach equilibrium, hence the word quasi-static.

Strategy:

To determine the range of specified tension in the PHC to be simulated, a few hand-calculations where performed. It has earlier been emphasized that the CT at the entering point into the SSI must be held in tension to avoid compression and potential buckling in the tubing. Sufficient top tension must hence be applied. The tension can only be applied in the winch wire holding the PHC. The required specified tension in the PHC to keep effective tension in bottom of CT zero is estimated as follows.

The effective tension in bottom of CT is set to zero, i.e. the tension in the PHC is determined by the weight of suspended equipment (CT and TSI). The density of whatever is inside the CT will affect the effective tension. The CT is assumed to be filled with seawater in the following calculations. In a water depth of 100m, the length of CT stretching from top of the SSI to the TSI at mid-length is approximately 68m.

$$L_{CT} = 68m$$

Using data from
Table 9, the dry weight of the CT is:

$$W_{CT,dry} = w * L_{CT} = 8{,}038\frac{kg}{m} * 68m \approx 547kg$$

For simplicity it is assumed that the entire CT string is submerged in water. Assuming a steel density of 7850 kg/m^3 and a seawater density of 1025kg/m^3 the wet weight becomes:

$$W_{CT,wet} = 547kg * \left(1 - \frac{1025}{7850}\right) \approx 476kg$$

The applied tension in the PHC is applied through the TSI. The mass of the TSI is:

$$W_{TSI} = 15000kg$$

The total weight is thus:

$$W_{tot} = W_{CT,wet} + W_{TSI} = 15476kg$$

The tension in PHC when the effective tension at bottom of CT is zero is hence:

$$T_{PHC} = W_{tot} * g = 15476kg * 9{,}81\frac{m}{s^2} \approx 152kN$$

The specified tension in the PHC should always be sufficiently large, such that positive effective tension always is present in CT at entrance into SSI. The first simulation will hence be run with a specified tension in the PHC of:

$$T_{PHC,min} = 160kN$$

which is equal to an over-pull of approximately 8kN in CT at the point where CT enters the SSI.

The maximum specified tension to be simulated with was determined by the structural capacity of the CT. The material yield strength of the CT used for calculations is:

$$\sigma_y = 90000psi$$

The yield tension, F_y, is thus given by:

$$F_y = \sigma_y * A = \sigma_y * \frac{\pi}{4}(OD_{CT}^2 - ID_{CT}^2)$$

With inserted values:

$$F_y = 90000psi * 6894{,}76\frac{Pa}{psi} * \frac{\pi}{4}((0{,}073025m)^2 - (0{,}0635m)^2) * 10^{-3}$$

$$F_y \approx 633{,}8kN$$

The CT will experience a bending moment in case of an accidental loss of vessel position. A portion of the capacity will then be taken up by the bending moment (and pressure) as the CT bends when vessel offset increases. Thus, there would be no point to start a simulation with a tension in the CT close to F_y. Considering the bending moment only, the maximum bending moment before the CT yields is:

$$M_y = \frac{\sigma_y * I}{y} = \frac{\sigma_y * \frac{\pi}{64}(OD_{CT}^4 - ID_{CT}^4)}{\frac{OD}{2}}$$

With inserted values:

$$M_y \approx 10{,}16kNm$$

A simple linear resistance chart can then be made. Figure 52 below shows the relationship between allowable effective tension and bending moment (pressure and design factor is not included) for the CT. Be aware of that this is based on a simple hand calculation, but it is suitable to get an initial estimation of what parameters to start simulating with.

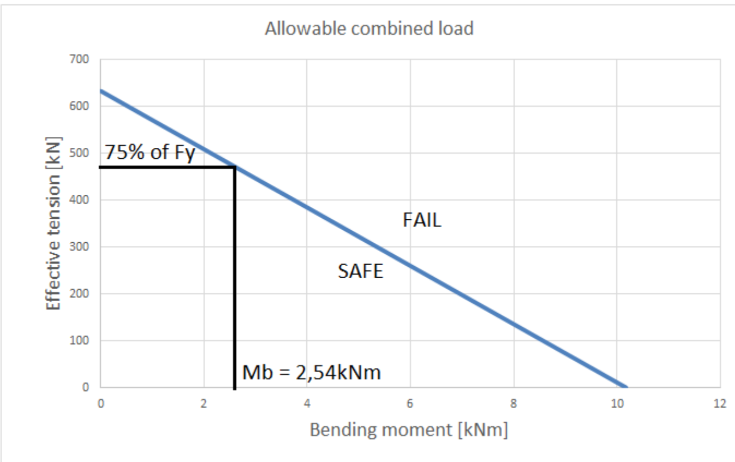


Figure 52 – Resistance chart

By taking the bending moment that will occur during the loss of position into account as well, I decided to not simulate with a tension in the CT exceeding 75% of F_y, which is equal to 475kN. The corresponding allowable bending moment is then 2,54kNm. When the CT is held in tension between the TSI and the SSI, the tension in the CT will be largest on top. The specified tension in PHC, by including the weight of the TSI, must hence be approximately:

$$T_{PHC,max} = 0{,}75 * \ F_y + m_{TSI} * g$$

With inserted values:

$$T_{PHC,max} = 0{,}75 * 633{,}8kN + 15000kg * 9{,}81\frac{m}{s^2} * 10^{-3} \approx 620kN$$

Twenty-four simulations will thus be run by varying the specified tension (ST) in the PHC from 160kN to 620kN in steps of 20kN. Summary is shown in Table 12.

Table 12 - Load case #1

Simulation #	H [m]	T [s]	CS [m/s]	CD [deg]	WD [deg]	ST [kN]	Step
1-24	0	0	0	0	0	160-620	20

It is assumed that the capacity of the topside injector is sufficient to handle the weight. Injectors vary in capacity, typically ranging from 60000lb-140000lb (267kN-623kN).

Comment: The calculations above are based on the elastic limit. It is known that the CT string is plastically strained (fatigued) from being subjected to bend-cycling. It is thus accepted to go beyond the elastic limit of the CT. This is not considered here. See section 5.5 for more information on fatigue.

12.1.2 Load case #2

Objective:

The primary objective with load case #2 was to investigate dynamic loads at pre-defined critical points in the system. When waves are introduced, the system will be subjected to additional loads due to vessel motions and also the direct impact load of waves. It is pertinent to identify which effect, vessel motion or wave loads, is dominating the dynamic loading.

Offset specifications:

Offset specifications are presented in Table 13.

Table 13 – Time history file for load case #2

Stage	Time [s]	Primary X [m]
Build-up	-500,00	5,00
Stage 1	100,00	5,00
Stage 2	250,00	5,00

A large build-up time is required when simulating with waves. Orcaflex will then ramp up the wave height (and the offset) over the specified interval. Stage 1 is implemented to let the system stabilize. Stage 2 is the analysed stage. Note that the offset is developing during the build-up stage, and not during the analysed stage.

Strategy:

Loads increases due to vessel motion. To enable safe disconnect, the operating circles must be reduced to account for the wave loads. The offset (5m) in these simulations are introduced to create a scenario that includes both loss of position and waves.

The wave height, H_{max}, was chosen based on an analysis performed by Kongsberg for IOSS (classified as internal document). A significant wave height (H_s) of 3,5m was the limiting wave height for the operation.

$$H_{max} = 1{,}9 * H_s = 1{,}9 * 3{,}5m = 6{,}65m$$

The wave height chosen to simulate with was thus: $H_{max} = 7m$. Since the Airy wave type is chosen, all waves will have a wave height and period as specified. The wave direction is specified to -180 degrees, which means that waves will propagate towards the bow of the vessel only. It was decided to keep a significant back-tension in the CT at entering point into the SSI. In the OWCT drilling operations on the Butch field, the TSI and the SSI were synchronized manually, i.e. one operator controlled the TSI, while another controlled the SSI. Inaccuracy might then be an issue. It could then be purposeful to keep a significant back-tension in the CT, such that the inaccuracy becomes less critical. Hence, all simulations are run with a specified tension in the PHC of 240kN. This gives a back-tension of approximately 8,8 metric tons (86kN) in CT at SSI.

Modal analysis:

A modal analysis can be seen on as a check of the dynamic properties of the system. Before starting a dynamic simulation one should always investigate the natural periods of the system to identify possible resonance dynamics. The chosen range of wave periods to be simulated with should cover potential natural periods. Modal analysis is used to identify the natural periods of the system. Ocean current and waves have a dampening effect. However, hydrodynamic drag and other non-linear effects are not taken into account in the modal analysis.

Orcaflex has an in-built modal analysis function. In this thesis, the modal analysis is performed on the whole system, including both the subsea stack and the CT string. If the modal analysis were performed on the CT string or subsea stack only, important end effects may be neglected. Modal analysis is performed when the system is at a static state. Table 14 shows the modes with associated period and frequency obtained from the modal analysis.

Table 14 – 100m WD - Modal analysis results

Mode #	Period [s]	Frequency [Hz]
1	7,51	0,13
2	1,29	0,77
3	0,78	1,28
4	0,64	1,55
5	0,43	2,34

It is important to note that the natural periods are dependent on the geometrical stiffness of the system. The natural periods will hence vary with applied tension. The table above is for when specified tension in PHC is 240kN.

Mode 2 to 5 has, as seen from Table 14, very short natural periods. When simulating with regular waves, the possibility for such short wave periods to occur is dependent on the wave height. For a wave height representing a size to that of an operational limit, it is very unlikely that such short periods will have any significant wave energy. On the other hand, if irregular wave theory was used (e.g. JONSWAP), one would be able to decompose the frequency content, and probably find that some high frequencies (short periods) would be present that may excite e.g. mode 2. This was however not done in this thesis. Mode 1 has a natural period of 7,51s, and will be included in the range of wave periods to be simulated with. The shape of mode 1 can be seen in Figure 53 below.

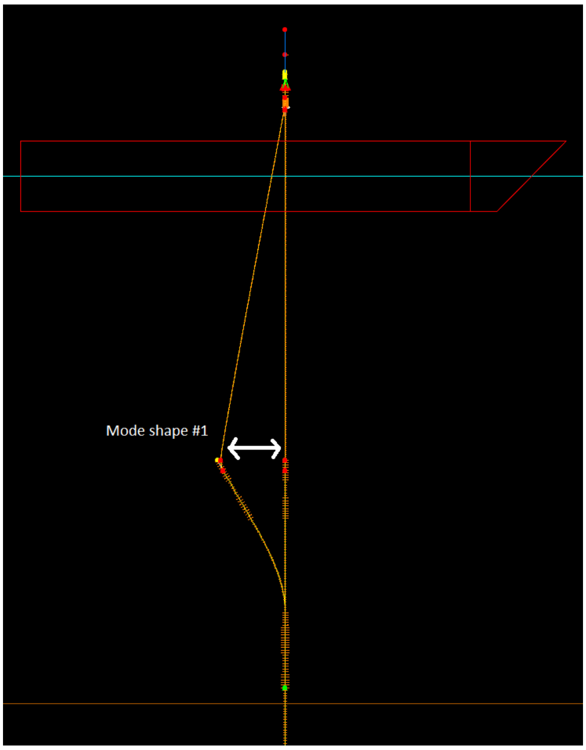


Figure 53 - Mode shape #1

In load case #2 the wave periods will be varied from T=6s to T=18s in steps of 0,5s for each simulation, with all other parameters at a constant value. Summary is shown in Table 15.

Table 15 - Load case #2

Simulation #	H [m]	T [s]	Step	CS [m/s]	CD [deg]	WD [deg]	ST [kN]
1-25	7	6-18	0,5	0	0	-180	240,00

12.1.3 Load case #3

Objective:

Load case #3 is used as a sensitivity analysis, where the objective was to investigate the effects on system loads for downstream and upstream vessel offset conditions.

Offset specifications:

Offset specifications are presented in
Table 16.

Table 16 - Time history file for load case #3

Stage	Time [s]	Primary X [m]
Build-up	-20,00	0,00
Stage 1	1000,00	10,00

A build-up time of 20s is sufficient to ramp up the current speed to avoid system transients. An offset of 10m is simulated linearly over 1000s. Stage 1 is the analysed stage.

Strategy:

Figure 54 illustrates how the shape of the CT will look like with a vessel offset in upstream vs. downstream direction. The figure is just for illustrative purposes and does not display how the scenario is modelled in Orcaflex.

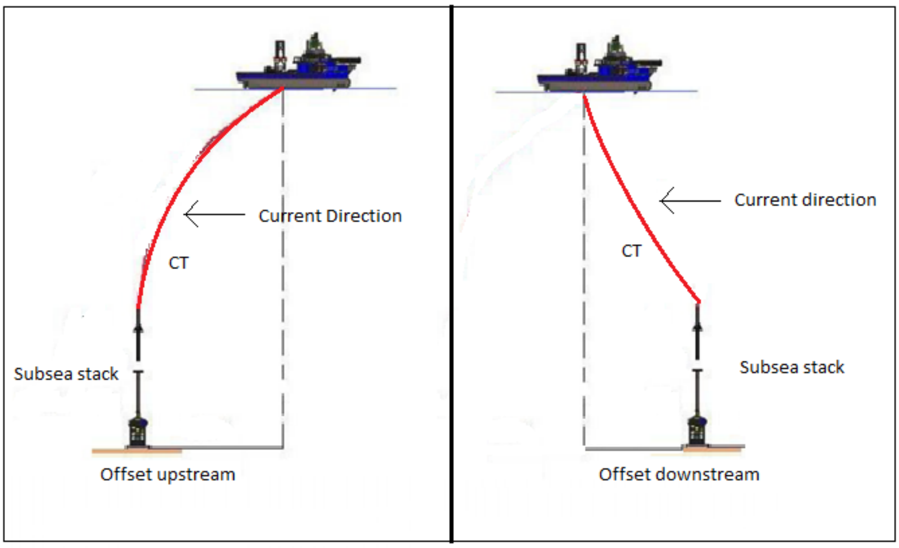


Figure 54 - Offset upstream vs. downstream

The parameter varied in load case #3 is the current direction (CD). Instead of adjusting the offset in the X-direction using the same current direction, as Figure 54 shows, a current direction of 0 and 180 degrees is instead used to simulate a vessel offset downstream and upstream, respectively. The Primary motion in X-direction is hence not adjusted, and the bow of the vessel will be facing in positive X-direction for both simulations.

Note: The current speed (CS) is multiplied by the factors specified in the Mariner and Bressay 1-year current profile in Figure 50. Summary is shown in Table 17.

Table 17 – Load case #3

Simulation #	H [m]	T [s]	CS [m/s]	CD [deg]	WD [deg]	ST [kN]
1	0	0	0,01	0,00	0	240,00
2	0	0	0,01	180,00	0	240,00

12.2 Load cases in 300m WD

12.2.1 Load case #4

Objective:

The objective with load case #4 is the same as for load case #1. The water depth is now 300m.

Offset specifications:

A new offset specification is implemented to compare the relative effects to that of 100m WD. A 10% offset in 300m WD is 30m. The time history file is shown in Table 18.

Table 18 - Time history file for load case #4

Stage	Time [s]	Primary X [m]
Build-up	-1,00	0,00
Stage 1	1000,00	30,00

Stage 1 is the analysed stage.

Strategy:

Since comparison is wanted between the models in 100m and 300m WD, it would be beneficial to compare them with the same effective tension in CT at entering point into SSI (subsea end). In order to accurately do this, hand calculations will be somewhat imprecise. Instead, a static simulation for the 100m-model was performed in Orcaflex. In 100m WD; 160kN applied top tension in PHC gave an effective tension of 12kN in CT at funnel exit and 6kN in CT at SSI. In the strategy section in load case #1, the hand calculated effective tension in CT at SSI was 8kN (i.e. a difference of only 2kN). This is a good verification of the model. To establish the same effective tension in CT at SSI in 300m WD, the values can be extrapolated to 300m WD as Figure 55 shows. Calculations performed are not shown.

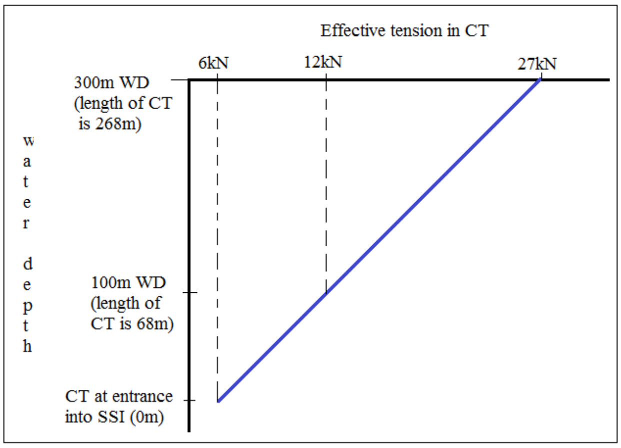


Figure 55 - Effective tension in CT

Approximately 15kN extra applied tension in PHC is required to get the same effective tension in CT at entrance into SSI for 300m WD.

$$T_{PHC,min} = 175kN$$

Since the tension in CT at funnel exit for 300m WD will be higher than for 100m WD because of the weight of the CT itself, I decided to only simulate to

$$T_{PHC,max} = 615kN$$

Twenty-three simulations will thus be run by varying the specified tension (ST) in the PHC from 175kN to 615kN in steps of 20kN. Summary shown in Table 19.

Table 19 - Load case #4

Simulation #	H [m]	T [s]	CS [m/s]	CD [deg]	WD [deg]	ST [kN]	Step
1-23	0	0	0	0	0	175-615	20

A full table displaying the specified tension in PHC in relation to effective tension in CT at funnel exit and at entering point into SSI are shown in Appendix B.

12.2.2 Load case #5

Objective:

Same as in load case #2, only in 300m WD.

Offset specifications:

Offset specifications are presented in Table 20. A 5% offset is 15m in 300m WD.

Table 20 - Time history file for load case #5

Stage	Time [s]	Primary X [m]
Build-up	-500,00	15,00
Stage 1	100,00	15,00
Stage 2	250,00	15,00

Strategy:

To obtain the same effective tension in CT at entering point into SSI as for the model in 100m WD, the specified tension in PHC was set to 255kN.

Modal analysis:

Table 21 shows the modes with associated period and frequency obtained from the modal analysis.

Table 21 – 300m WD - Modal analysis results

Mode #	Period [s]	Frequency [Hz]
1	8,189	0,122
2	4,781	0,209
3	2,439	0,410
4	1,629	0,614
5	1,222	0,818

Mode 1 has a natural period of 8,189s, and will be included in the range of wave periods to be simulated with. In load case #5 the wave periods will be varied from T=6s to T=18s in steps of 0,5s for each simulation, with all other parameters at a constant value. Summary is shown in Table 22.

Table 22 - Load case #5

Simulation #	H [m]	T [s]	Step	CS [m/s]	CD [deg]	WD [deg]	ST [kN]
1-25	7	6-18	0,5	0	0	-180	255,00

13 Post-processing

13.2 Choosing a code

The OWCT system will be subjected to combined loads. To assess operating limitations in an OWCT system it is necessary to investigate how the combined loads relate to the associated structural capacity, i.e. utilization of capacity. To do this, a code must be implemented.

The structural integrity of the CT at funnel exit and the bottom of the lubricator pipe when subjected to combined loads are analysed using ISO 13628-7:2005 (Petroleum and natural gas industries – Design and operation of subsea production systems – Part 7: Completion/workover riser systems) [35]. ISO 13628-7 uses the limit state design principle. Net internal overpressure is assumed in all calculations.

The CT string, after being reeled off the reel and onto the gooseneck has undergone plastic strains may have residual internal stresses as it leaves the topside injector because of the repeated bending cycles. This may have consequences for CT load estimates and is further elaborated on in chapter 15.

13.2.1 ISO 13628-7 code check

The following ISO 13628-7 code check has been applied for net internal overpressure in pipe sections:

"*Pipe members subjected to effective tension, primary (load controlled) bending moment and net internal overpressure shall be designed to satisfy the following condition at all cross-sections*" as given in Equation 3.1:

$$\left(\frac{T_e}{F_d * T_{pc}}\right)^2 + \frac{|M_{bm}|}{F_d * M_{pc}} * \sqrt{1 - \left(\frac{p_{int} - p_o}{F_d * p_b}\right)^2} + \left(\frac{p_{int} - p_o}{F_d * p_b}\right)^2 \leq 1 \qquad (1)$$

where

- T_e is the effective tension;
- T_{pc} is the plastic tension capacity of the pipe;
- F_d is the design factor;
- M_{bm} is the bending moment in the pipe;

- M_{pc} is the plastic bending moment capacity of the pipe;
- p_{int} is the internal pressure in the pipe;
- p_o is the external pressure;
- p_b is the burst pressure of the pipe.

The pipe capacities are given in Equation 2, 3 and 4:

$$M_{pc} = \alpha_{bm} * \sigma_y * Z = \alpha_{bm} * \sigma_y * \frac{1}{6}[D_o^3 - (D_o - 2 * t_2)^3] \quad (2)$$

where

- α_{bm} is the pipe cross-section slenderness parameter;
- Z is the pipe plastic section modulus;
- D_o is the specified or nominal pipe outside parameter;
- t_2 is the pipe wall thickness without allowances;

Comment: t_2 is set equal to the nominal pipe wall thickness as specified for both CT and lubricator pipe.

$$T_{pc} = \sigma_y * A_c = \sigma_y * (D_o - t_2) * t_2 \quad (3)$$

where

- A_c is the pipe cross-section area;
- σ_y is the design yield strength;

$$p_b = 1,1 * (\sigma_y + \sigma_u) * \frac{t_2}{D_o - t_2} \quad (4)$$

where σ_u is the design ultimate tensile strength. Materials used in subsea production systems must fulfil a certain ductility requirement. To simplify the calculation process, σ_u is given by Equation 5:

$$\sigma_u = \frac{\sigma_y}{0,92} \quad (5)$$

The cross section slenderness parameter, α_{bm}, is given by Equations 6 to 8:

$$\alpha_{bm} = 1,00 \quad \text{for} \quad \frac{\sigma_y * D_o}{E * t_2} \leq 0,0517 \quad (6)$$

$$\alpha_{bm} = 1,13 - 2,58 * \left(\frac{\sigma_y * D_o}{E * t_2}\right) \quad \text{for} \quad 0,0517 < \frac{\sigma_y * D_o}{E * t_2} \leq 0,1034 \quad (7)$$

$$\alpha_{bm} = 0,94 - 0,76 * \left(\frac{\sigma_y * D_o}{E * t_2}\right) \quad \text{for} \quad 0,1034 < \frac{\sigma_y * D_o}{E * t_2} \leq 0,170 \quad (8)$$

The effective tension, T_e, is given by Equation 9 (tensile axial force is positive):

$$T_e = T_w - p_{int} * A_{int} + p_o * A_o \qquad (9)$$

where

- T_w is the true wall tension (i.e. axial stress resultant found by integrating axial stresses over the cross-section);
- A_{int} is the internal cross-section area of the pipe, might be occupied by fluid content;
- A_o is the external cross-section area of the pipe giving buoyancy if submerged.

13.2.2 Base calculations

The utilization calculations performed using ISO 13628-7 are outlined in this section.

CT and lubricator pipe properties used in calculations are shown in Table 23 and Table 24 below. The ultimate yield strength has been calculated according to Equation 5. Be aware of that the yield strength and the E-modulus is not a part of the models in Orcaflex.

Table 23 - CT properties

Coiled tubing				
Outer diameter, Do	2,875	in	0,073025	m
Wall thickness, t2	0,188	in	0,00478	m
E-modulus, E	-		2,06E+11	Pa
Yield strength, σy	90000	psi	6,21E+08	Pa
Ultimate yield strength, σu	97826,09	psi	6,74E+08	Pa

Table 24 - Lubricator pipe properties

Lubricator pipe				
Outer diameter, Do	10,75	in	0,273	m
Wall thickness, t2	7,0866	in	0,18	m
E-modulus, E	-		2,06E+11	Pa
Yield strength, σy	80000	psi	5,52E+08	Pa
Ultimate yield strength, σu	86956,52	psi	6,00E+08	Pa

The pipe cross-section slenderness parameter (α_{bm}) are calculated using Equation 6,7 and 8, while the pipe plastic section modulus (Z) are calculated using Equation 2. Values are shown in Table 25.

Table 25 - Cross-section slenderness parameter and plastic section modulus of CT and lubricator pipe

	Coiled tubing	Lubricator pipe
Pipe cross-section slenderness parameter, αbm	1	1
Pipe plastic section modulus, Z [m^3]	2,23E-05	0,002420792

The pipe capacities were then calculated and listed in Table 26.

Table 26 - Pipe capacities

	Coiled tubing		Lubricator pipe	
Mpc	13 825	Nm	1 335 262	Nm
Tpc	635 337	N	18 261 191	N
Pb	99 668 459	Pa	260 037 725	Pa

The design factor, F_d, is a part of the acceptance criteria, and is chosen dependant on three different scenarios:

- Normal operation: $F_d = 0{,}67$
- Extreme/temporary operation: $F_d = 0{,}8$
- Accidental: $F_d = 1$

1. Design factor for CT

Since CT fatigue not is accounted for, choosing $F_d = 1$ would probably not be representable. However, choosing $F_d = 0{,}67$ may, for the same reason, be somewhat conservative since the CT is plastically strained during deployment/retrieval. It was thus chosen to use $F_d = 0{,}8$.

2. Design factor for lubricator pipe

$F_d = 0{,}67$ for a normal operation scenario is used.

Comment: The choice of design factor is an important decision. The most appropriate design factor to use for CT in an open water scenario can be further discussed.

An external pressure equal to zero is assumed for all calculations. This is a conservative approach.

$$P_o = 0$$

The internal pressure is set to be

$$P_{int} = 5000\, psi$$

in calculations for both CT and lubricator pipe. A resistance chart for CT is shown below in Figure 56 for the chosen design factor and internal pressure. Max effective tension is 458,3kN and max bending moment is 9,97kNm. Utilization is less than 1 (u<1) anywhere below the blue line.

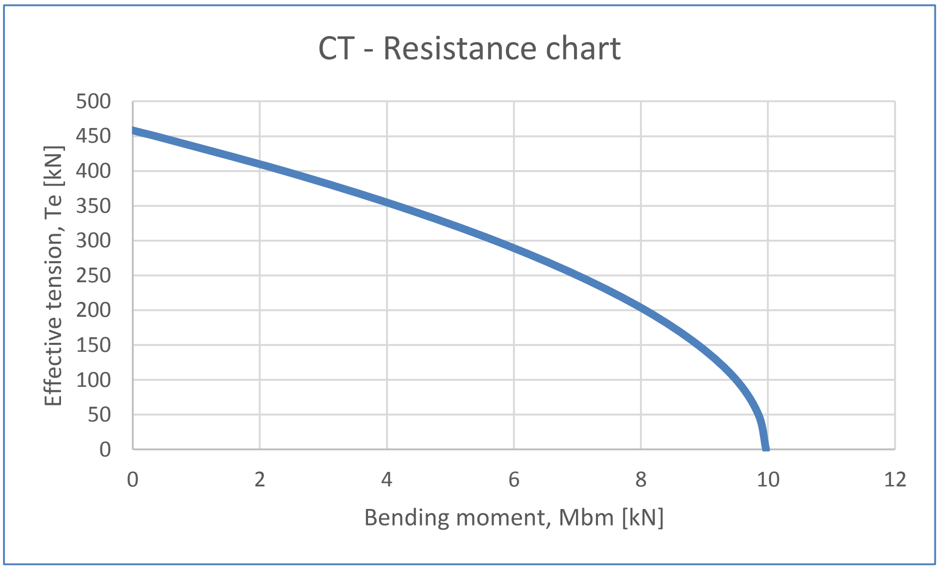


Figure 56 - CT - resistance chart

Figure 57 shows the resistance chart for the lubricator.

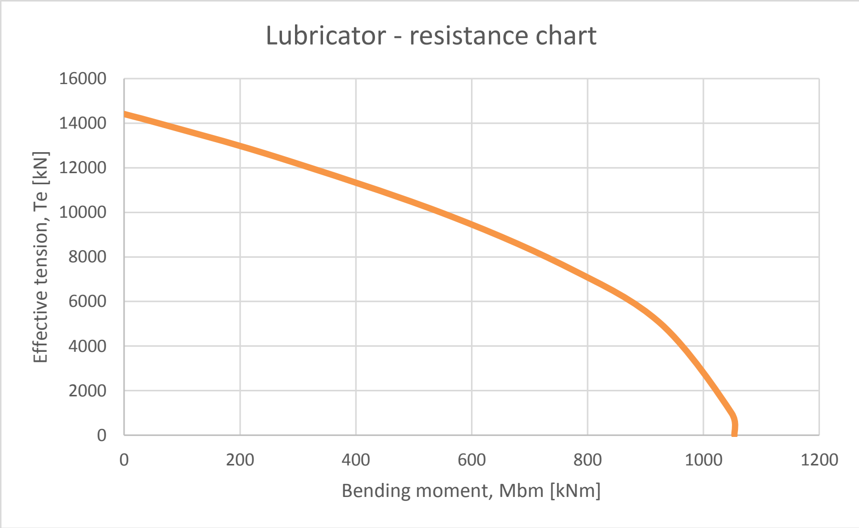


Figure 57 - Lubricator - resistance chart

The above calculations form the base for the utilization results. The data for the effective tension, T_e, and the bending moment, M_{bm}, during the offset were extracted from Orcaflex and put into a separate Excel-sheet used for calculation of the capacity utilization. This was done for both the CT at funnel exit and the bottom of the lubricator pipe for both the 100m-model and the 300m-model for all simulations.

13.2.2 Example

The following plots serves as an example to demonstrate how the extracted data from the simulations in Orcaflex was used to calculate the utilization. In this example, the data extracted from the 100m-model for the simulation with 240kN specified tension in the PHC (load case #1) is used. The same procedure was used when calculating the utilization for all simulations.

Figure 58 below shows the bending moment in the CT at funnel exit during the offset.

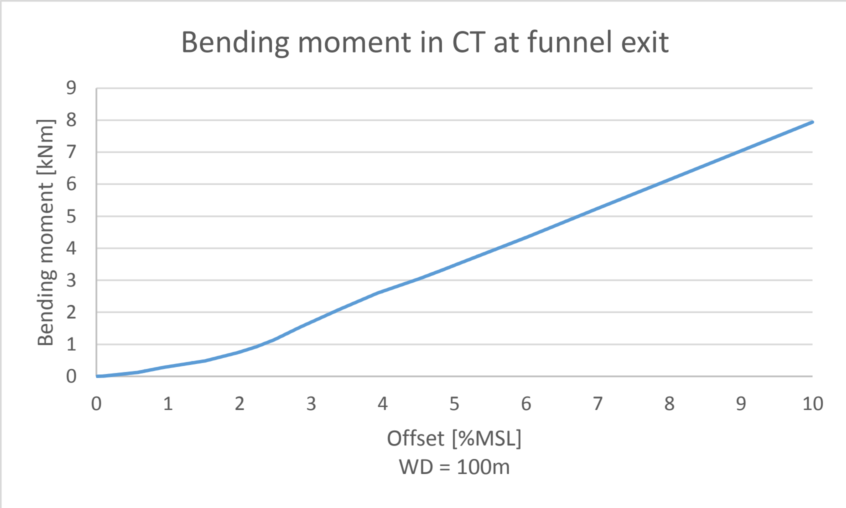


Figure 58 - Bending moment in CT at funnel exit

Figure 59 below shows the effective tension in the CT at funnel exit during the offset.

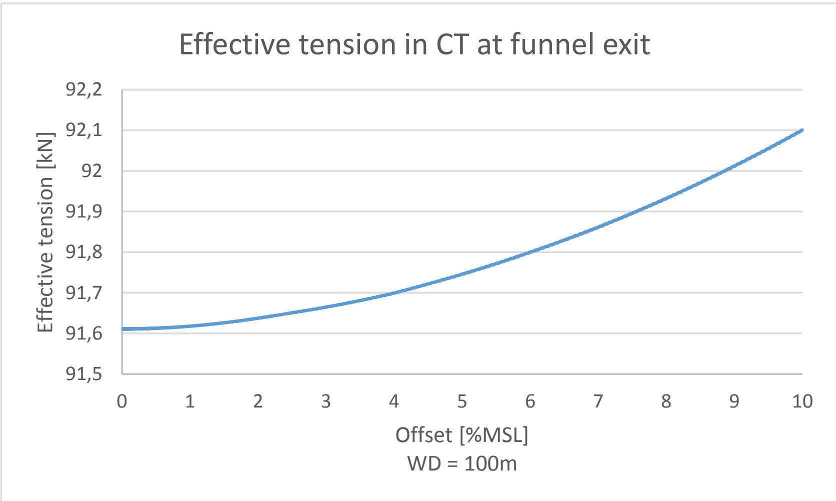


Figure 59 - Effective tension in CT at funnel exit

Figure 60 below shows the bending moment in the bottom of the lubricator pipe during the offset.

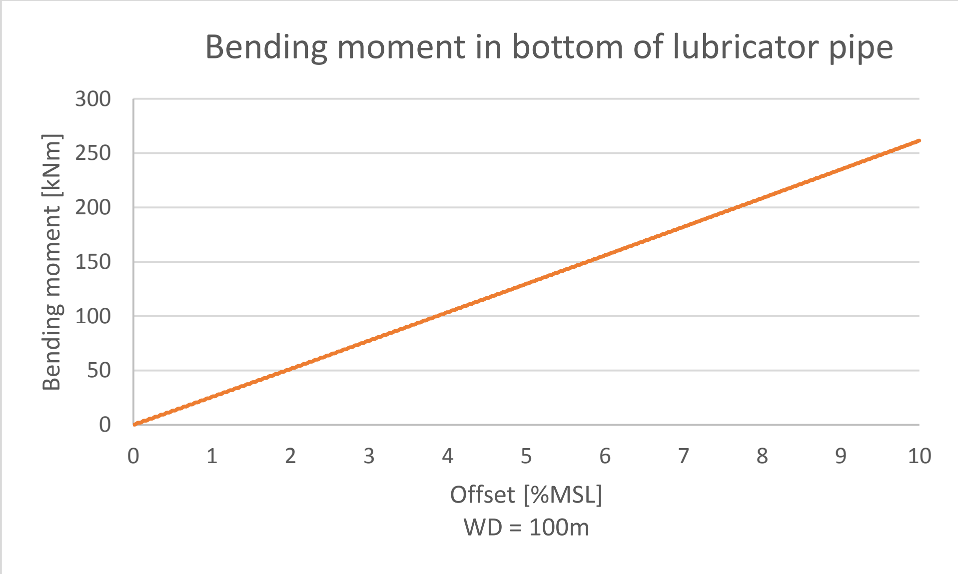


Figure 60 - Bending moment in bottom of lubricator pipe

Figure 61 below shows the effective tension/compression in the bottom of the lubricator pipe during the offset.

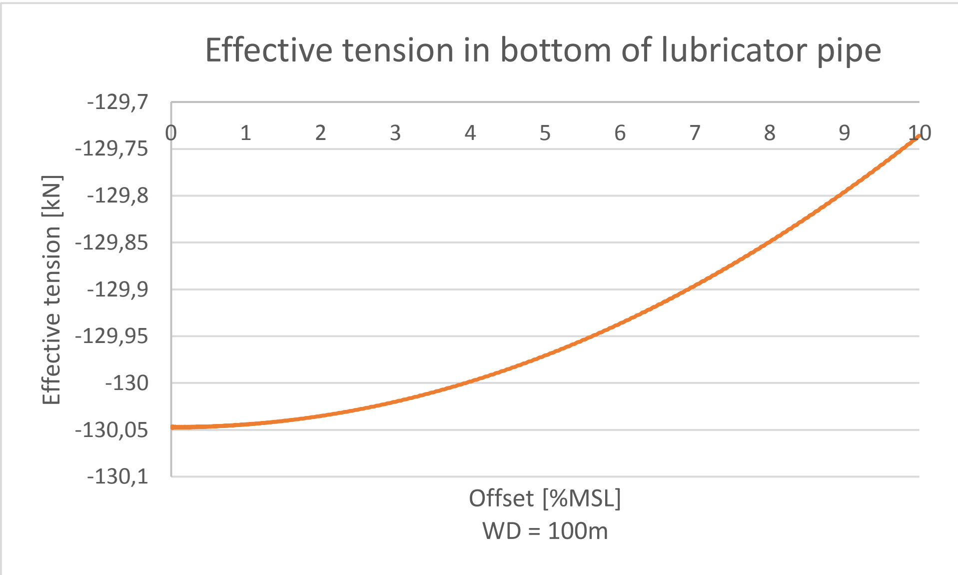


Figure 61 - Effective tension in bottom of lubricator pipe

Note that the lubricator is in compression. The design criterion of Equation 1 is the von Mises criterion. There will be additional effects due to that the subsea stack is in compression, but these will not be considered in this thesis.

It is also worth mentioning that as the tension in CT is increased, the lubricator pipe will shift from being in compression to be in tension.

Since the effective tension in the CT and the lubricator pipe will more or less be constant for a given specified tension in the PHC, the bending moment will be the governing factor for change in capacity utilization.

Using Equation 1 in section 12.2.1, the capacity utilization, u, was calculated for both the CT at funnel exit and at bottom of the lubricator pipe during the specified offset. Utilization of CT at funnel exit and at bottom of lubricator pipe is displayed in Figure 62 and Figure 63, respectively.

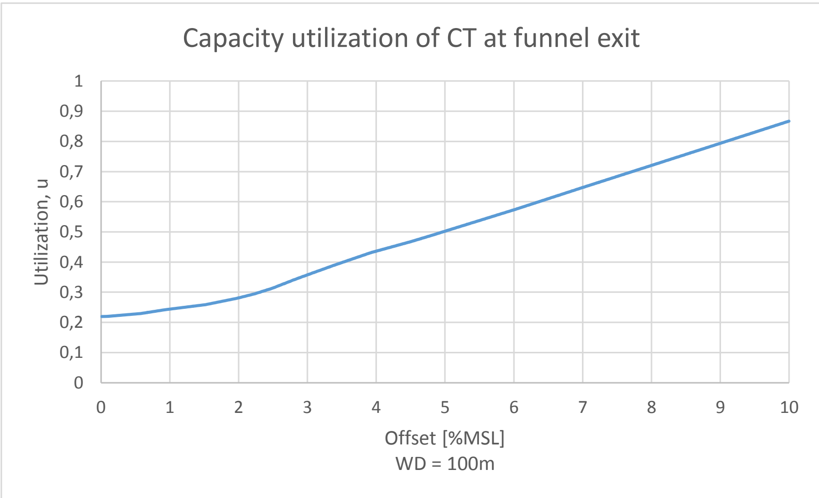


Figure 62 - Capacity utilization of CT at funnel exit

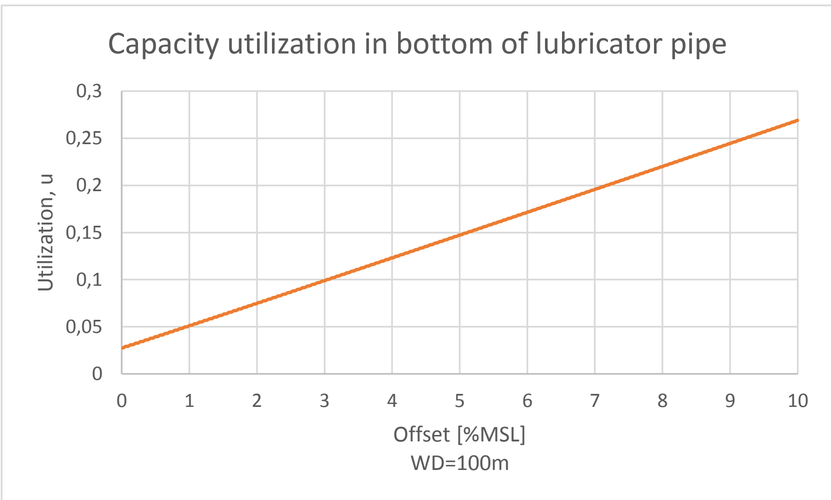


Figure 63 - Capacity utilization in bottom of lubricator pipe

After performing this procedure for all simulations using load case #1, the results can be displayed in one big chart representing the capacity utilization curves for the simulations in 100m WD and 300m WD. The specified tension in the PHC, T_{PHC}, is varied in steps of 20kN for each simulation. Results are displayed in chapter 14.

14 Results

This chapter serves to present the results obtained from the simulations done in Orcaflex. The amount of information that can be extracted from Orcaflex is vast. Before analysing the model, it was thus important to identify what to extract and where in the system to extract it from.

Since a lot of work is done prior to obtaining the results, it was decided to include the method used for analysis as a part of this chapter. This is done to make it easier for the reader to comprehend the results.

14.1 Determining system hotspots

From a simulation using load case #1 (100m-model) and a specified tension in PHC equal to 240kN, the maximum bending moment in the CT and the subsea stack during the offset are extracted from Orcaflex. Considering the vessel offset in these simulations, the bending moment will initially be zero in the CT and the subsea stack (dynamic motions not included), and will increase as the vessel offset increases. The maximum bending moment shown in the plots will thus be when the vessel offset is 10m (10%MSL).

14.1.1 CT hotspots

In Figure 64 below, the bending moment versus the length in CT is shown for the 100m-model. The length of the CT is defined from bottom to top (0m = CT at entering point into SSI). It is easily seen that the critical points in the CT are at the funnel exit and at the entering point into SSI. The bending moments will vary with specified tension in PHC, i.e. the geometric stiffness.

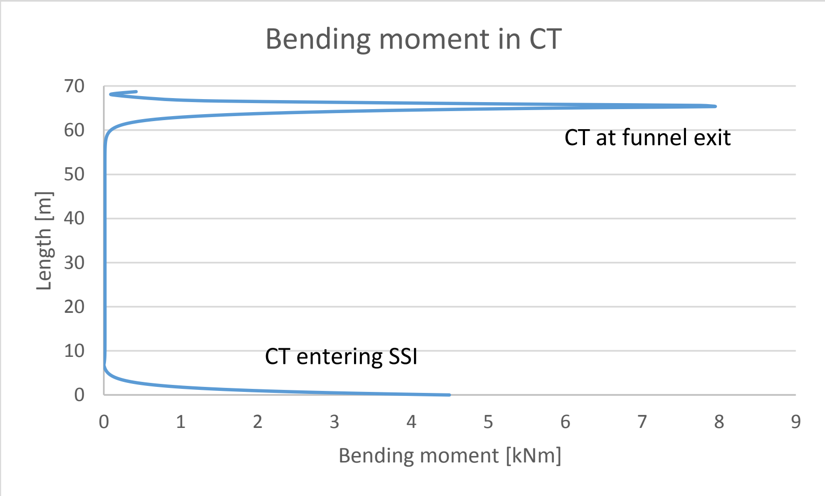


Figure 64 - Bending moment in CT

14.1.2 Subsea stack hotspots

In Figure 65 below, the bending moment in the subsea stack (wellhead not included), increases naturally towards the seabed. However, the XMT and the WCP are solid structures, while the lubricator pipe is a quite slender pipe. It is thus expected that the bending stress will therefore be larger there compared to in the XMT and the WCP. The bottom of the lubricator pipe will therefore be the base for further analysis.

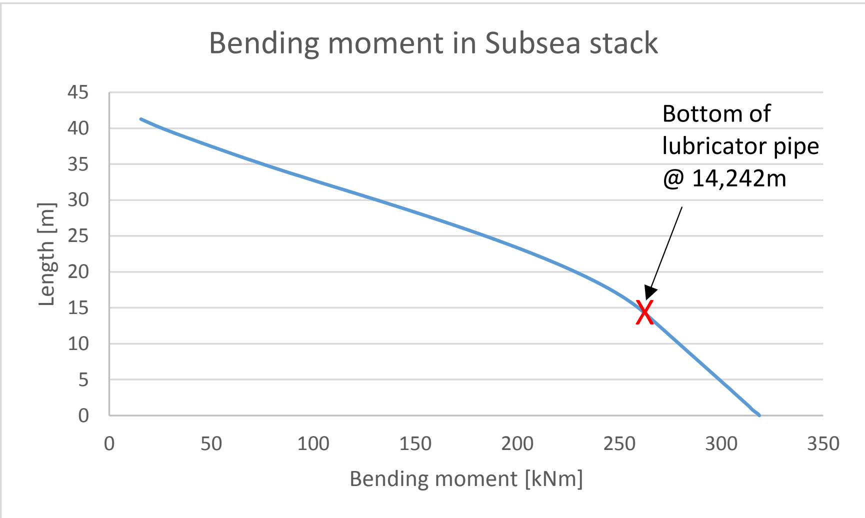


Figure 65 - Bending moment in Subsea stack

14.1.3 Effect of curvature of subsea stack

One of the objectives with load case #1 was to investigate how the bending moment changed with specified tension in the PHC during a vessel offset. The maximum bending moment, in the CT and the subsea stack, at critical points were thus extracted from all simulations using load case #1. The specified tension in the PHC was then plotted against the maximum bending moment during the offset, which is displayed in Figure 66 below. The primary (leftmost) Y-axis represents the bending moment in the CT, while the secondary (rightmost) Y-axis represents the bending moment in bottom of the lubricator pipe.

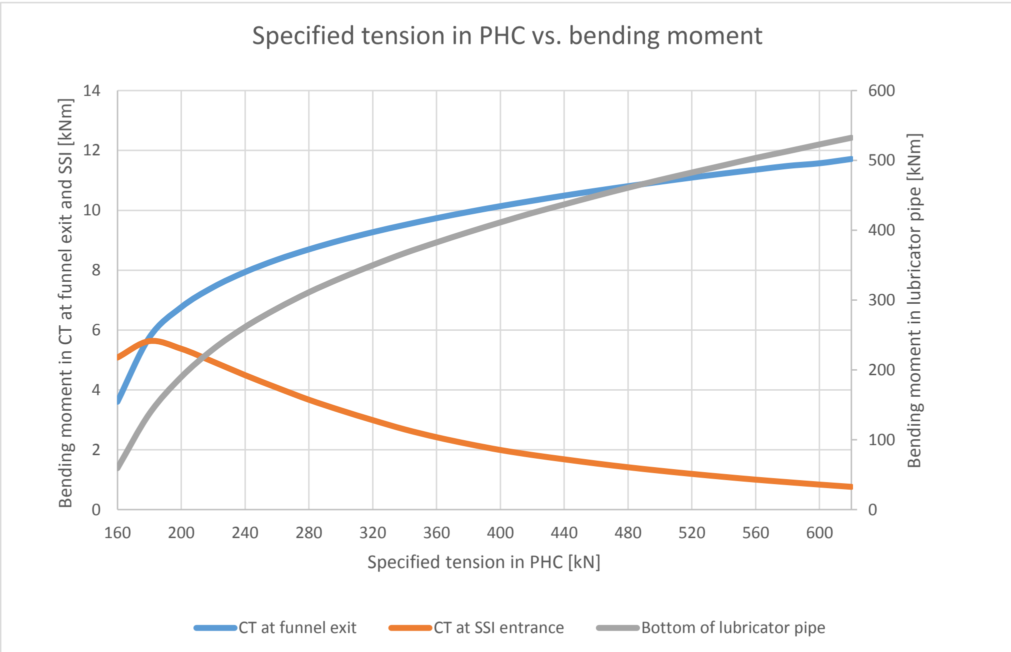


Figure 66 - Specified tension in PHC vs. bending moment at critical points

The interesting observation here is that the bending moment in the CT at entering point into SSI decreases with higher applied tension in the PHC. On the contrary, the bending moment in the CT at funnel exit and in bottom of the lubricator pipe increases. The reduced bending moment in bottom of the CT is a result of the induced curvature of the subsea stack. The curvature of the subsea stack causes the SSI to be more in-line with the CT string.

With 160kN specified tension in PHC, the effective tension in CT at SSI is 6kN, i.e. a very low over-pull. It is seen that the bending moment there exceeds the bending moment in CT at funnel exit, before the curve "breaks" and the bending moment decreases. This has to do with how the structural stiffness of the subsea stack is modelled and how the boundary conditions for CT/SSI interface is modelled.

In Figure 67 below, it can be seen that the subsea stack is more curved in the rightmost illustration, where the specified tension in PHC is 620kN, compared to the leftmost illustration (200kN). Be reminded that 620kN is a very high applied tension considering the capacity of the CT. It is just used in this context to illustrate the effect on the subsea stack.

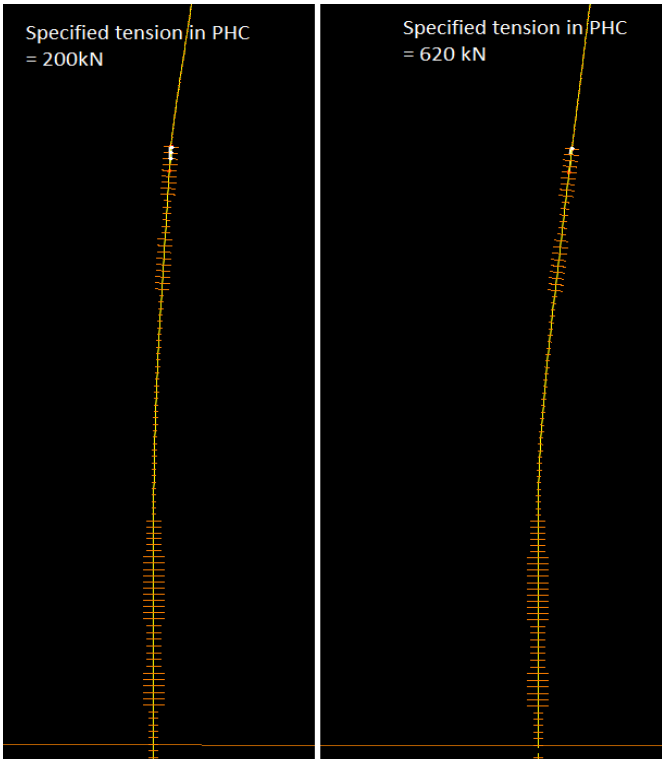


Figure 67 – Illustration of subsea stack curvature

The curvature of the subsea stack was extracted from Orcaflex from the two simulations with 200 and 620kN specified tension in PHC. The comparison can be seen in Figure 68 below. The bending stiffness of the lubricator pipe is relatively low, which results in significant curving, while the rest of the stack has a curvature of approximately zero in both simulations.

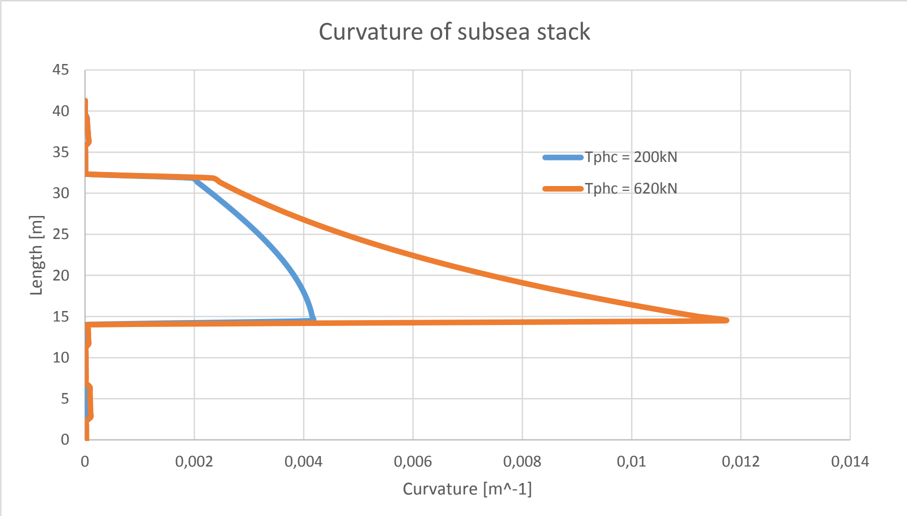


Figure 68 - Curvature of subsea stack

In reality the LLP is designed to bend if the stack experiences excessive forces. This is not modeled, and the LLP is present in this model as a massive steel pipe.

14.1.4 Effect of funnel

In the 100m-model with loads as specified in load case #1, a sensitivity analysis was performed to validate that the funnel had the desired effect. The primary function of a funnel is to reduce the pitch induced bending moment. However, since no waves are present in this simulation, the main function is to reduce the bending moment due to vessel offset. Since some uncertainty is tied to the modelled funnel it would be pointless to include a funnel that would increase the bending moment compared to a system with no funnel. A funnel will have its dimensions altered depending on size of the CT used. The OD of the CT used in this thesis is 2 7/8".

Since the funnel is designed as a massless obstacle, it was simply deleted in the model to do the sensitivity simulation. However, the point expected to experience higher bending moment is now the CT below the TSI. It is thus important to extract the bending moment from that point, as Figure 69 below shows.

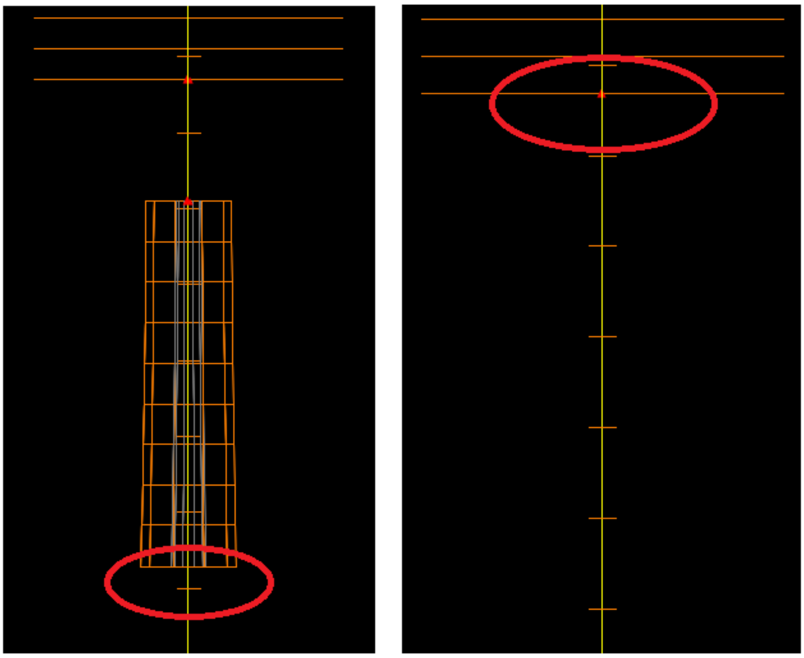


Figure 69 – Extraction of bending moment in CT with/without funnel

The extracted bending moment in CT at funnel exit and below TSI for the two simulations were then plotted against the vessel offset as shown in Figure 70 below. It is seen that the bending moment will be lower with a funnel present during the entire offset. The bending moment at funnel exit is 7,94kNm, while it is 10,06kNm below TSI at an offset of 10m. It is worth noticing that the slope representing CT at TSI is linear, while the slope representing CT at funnel exit is not linear for the first few meters of offset. This is a result of the vertical contact point displacement between CT and funnel, and is explained further in section 14.2.1.

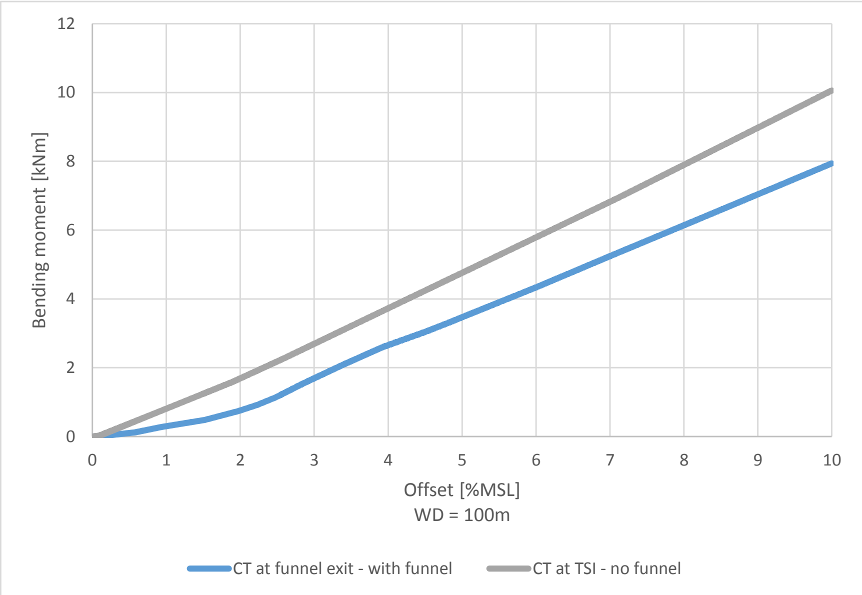


Figure 70 - Offset vs. bending moment - with/without funnel

The funnel reduces the initial bending moment with respect to offset by “hosting” the CT along the curvature of the funnel. When the contact point between CT and funnel reaches the funnel exit, i.e. the CT has contact with the entire length of the inner side of the funnel (which occurs at an offset around 2-3m), the most interesting observation is found in the relationship between the two curves; one curve is almost a parallel displacement of the other. This could mean that the initial bending moment (with respect to offset) could be further reduced by optimizing funnel dimensions, and the effect would be sustained throughout the offset. However, this must be investigated before any conclusions are drawn.

Considering that the funnel had the effect of reducing the bending moment, it was decided to keep the funnel in all simulations.

The bending moment in CT at entering point into SSI was also investigated with and without funnel. Negligible change was noticed, which was expected, and it was therefore decided to not include the results.

14.1.5 Summary of hotspots

Figure 71 below shows the hotspots of the system. These points form the base for further analysis.

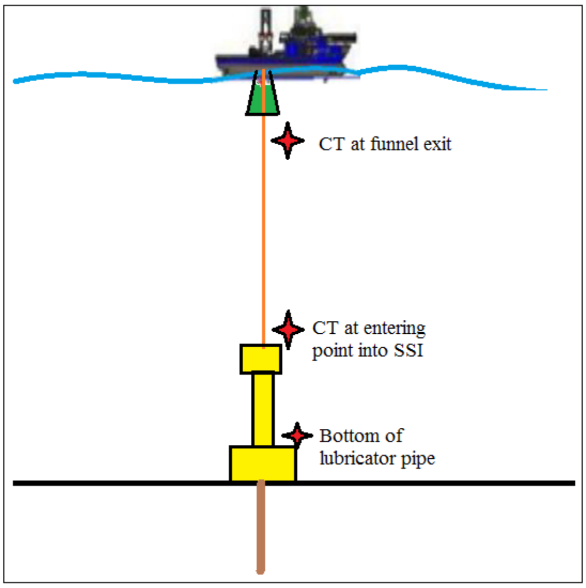


Figure 71 - System hotspots analysed

Seeing that the most critical point in the CT is at funnel exit, and in bottom of the lubricator pipe, it was decided to check how the loads compared to their associated structural capacity.

14.2 Effect of applied tension

The specified tension in the Passive heave compensator is used as a reference tension to compare utilization between CT and lubricator pipe and to compare the two water depths. To check the associated effective tension in CT at funnel exit and at entering point into the subsea injector, the reader is referred to Appendix B. The associated effective tension in bottom of the lubricator pipe is also displayed there.

Comment: The ultimate offset limit for static conditions is when the loads exceed the structural capacities. When waves are introduced, the limit will naturally be much less depending on wave height and period.

14.2.1 Model in 100m WD – load case #1

The results displayed here are obtained by using the procedure explained in section 13.2.2. Figure 72 displays the results for CT at funnel exit for the 100m-model. The X-axis represents the offset, while the Y-axis represents the utilization. Each curve represents a different specified tension in PHC.

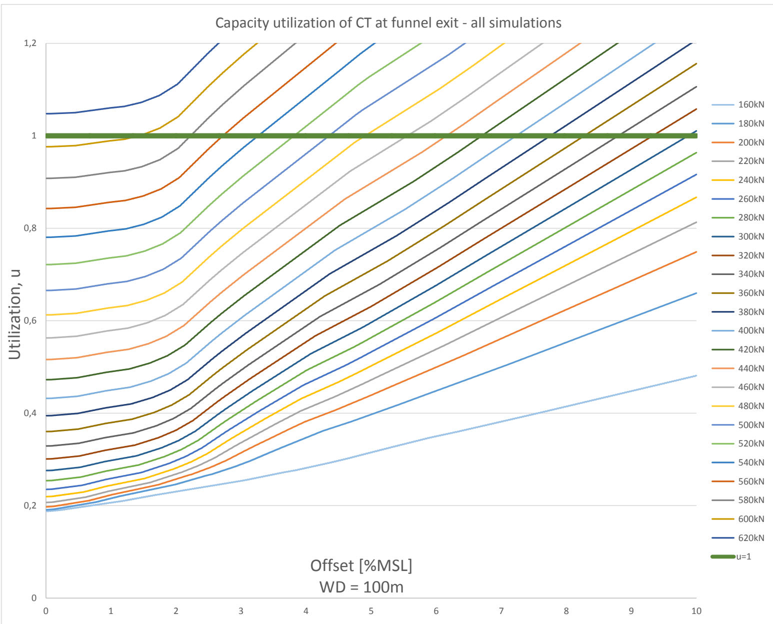


Figure 72 – 100m WD - utilization of CT at funnel exit - all simulations

The straight green line (u = 1) represents the maximum allowed utilization of the CT (with Fd=0,8 and Pint=5000psi). It is worth noticing that the slope of the curves representing applied tension in the PHC increases during the offset. As specified, the loads are extracted in the CT at the funnel exit. The CT will initially not have contact with the funnel exit, i.e. the contact point between CT and funnel is now further up in the funnel. The contact point will, as the offset develops, gradually move down to the funnel exit, and the bending moment will thus increase at the funnel exit, which is where loads are extracted. From observing Figure 72, this occurs at an offset of about 2-3m depending on the applied tension in the PHC.

Figure 73 below displays results at the bottom of the lubricator pipe.

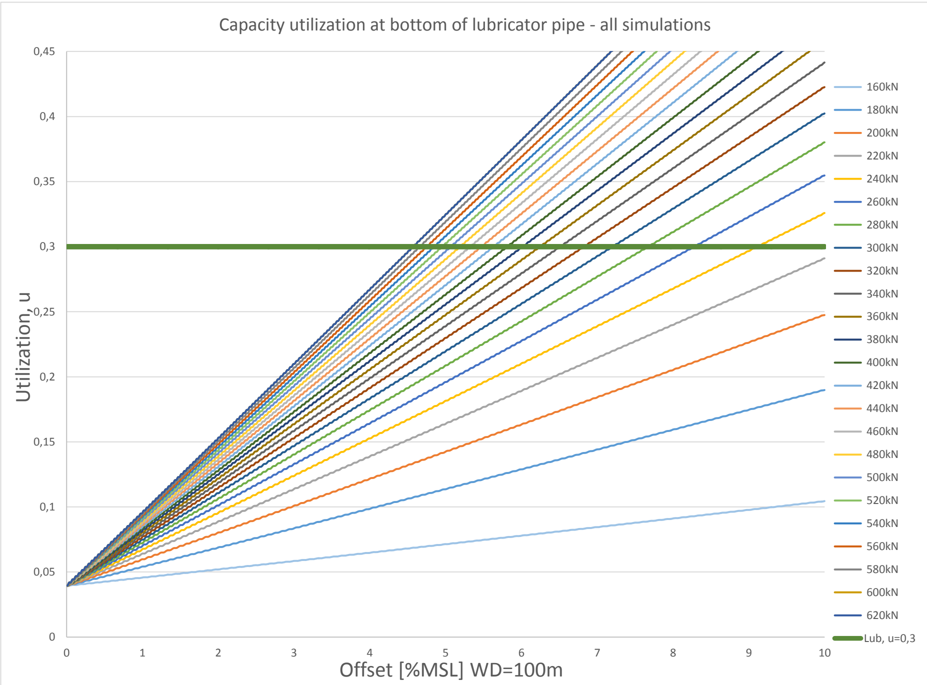


Figure 73 – 100m WD - utilization at bottom of lubricator pipe - all simulations

The straight green line (u = 0,3) represent 30% of the maximum allowed utilization of the lubricator pipe. This was implemented to illustrate the relationship between utilization in CT and lubricator for the same range of applied tension in PHC. When the vessel has no offset, and thereby no bending moment (since no waves are present), it is worth noticing that the applied tension has a negligible effect on the utilization of the lubricator pipe. Hence, the bending moment, which increases with applied tension, is clearly the governing factor for increased utilization in the lubricator pipe.

As the applied top tension is increased, the free-point (compression below and tension above) will be moved downwards on the CT string and eventually reach the subsea stack. The point being analysed in the subsea stack is at the bottom of the lubricator pipe. From the simulations it was observed that this point went from being in compression to be in tension as the applied top tension was increased. Compression reduces the effective structural capacity. The combined load equation for net internal overpressure in ISO 13628-7 has nonetheless been used to calculate the utilization, even if bottom of the lubricator pipe was in compression or tension. This was done to ease the analysis process and will have negligible effect on the utilization estimates, as the dominating load in the lubricator during a vessel loss of position is the bending moment.

Utilization of capacity for the CT at funnel exit is presented for maximum utilization (u=1).

The bottom of the lubricator pipe is presented for 30% of maximum utilization (u=0,3).

The offset and the specified tension in PHC are then extracted from where the curves cross the line (u = 1 for CT and u = 0,3 for lubricator pipe) in the two figures above. An operational envelope displaying the capacity utilization of the critical points in relation to the vessel's offset and the specified tension in the PHC is then obtained. Figure 74 shows the line representing maximum utilization of CT at funnel exit. Being above the blue line (CT, u=1) means that the combined loads will exceed the design capacity of the CT.

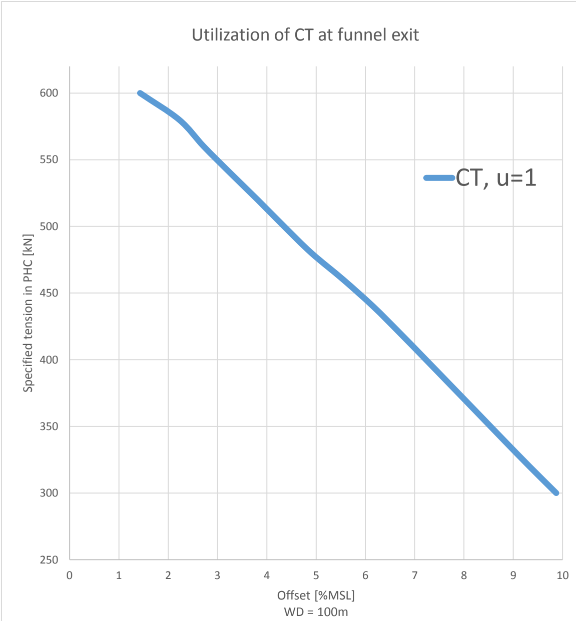


Figure 74 – 100m WD – CT operational envelope

Figure 75 below shows the line representing 30% of maximum utilization at bottom of lubricator pipe for the simulated range of specified tension in PHC. The line for maximum possible utilization (u=1) for the bottom of the lubricator pipe is not shown because the maximum capacity was never reached in any simulation.

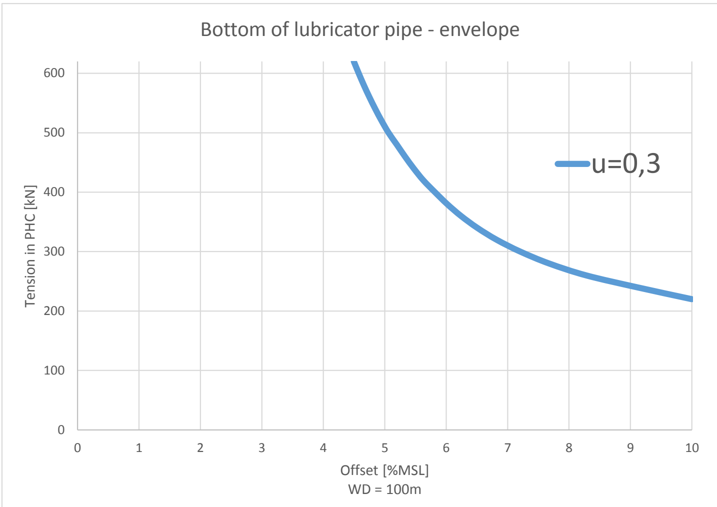


Figure 75 – 100m WD – Lubricator operational envelope

The two lines are then combined in a single plot as Figure 76 below shows.

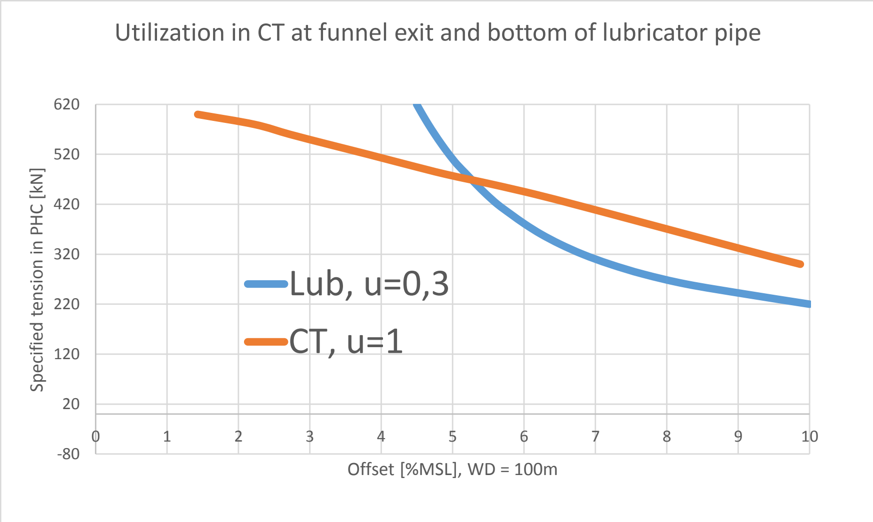


Figure 76 – 100m WD - Combined chart

Figure 76 above shows the relationship between utilization in CT at funnel exit and bottom of the lubricator pipe for the simulated range of applied tension. It is seen that when the CT string reaches its maximum design capacity, the bottom of the lubricator pipe will only be at 30% of its maximum design capacity. It is thus evident that the CT is the weak link in this specific modelled OWCT system. However, the size of the CT string plays a significant role here. A CT string with a higher structural capacity or a reduced structural capacity of the lubricator could change this conclusion for different OWCT system setups. The loads are of course also water depth dependent.

14.2.2 Model in 300m WD – load case #4

This section displays the results obtained from the model in 300m WD. The same procedure used for the model in 100m WD is used. Figure 77 below displays utilization vs. offset with different applied top tension for CT at funnel exit.

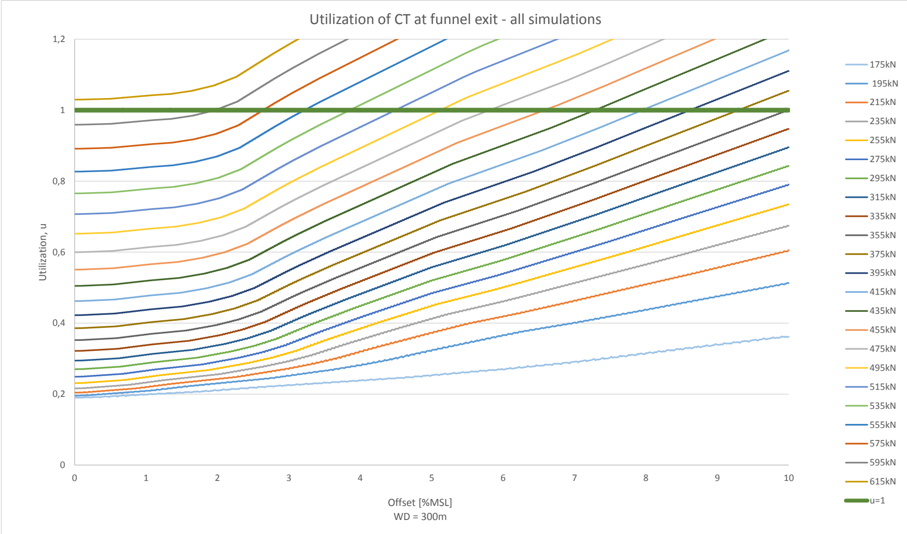


Figure 77 - 300m WD - utilization in CT at funnel exit

Figure 78 shows utilization at bottom of lubricator pipe.

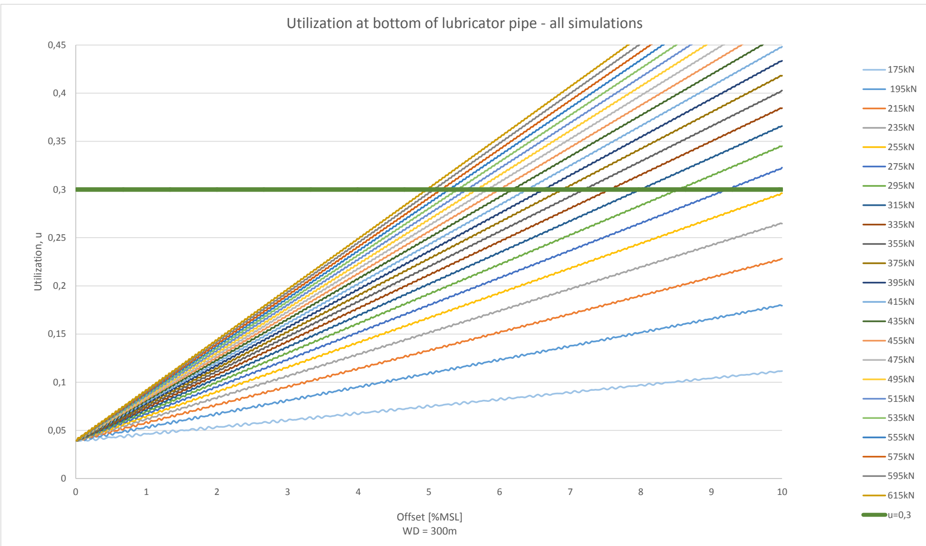


Figure 78 - 300m WD - utilization at bottom of lubricator pipe

Using the same procedure as done in section 14.2.1, a combined plot is made as Figure 79 below shows. The orange line represent maximum utilization (u=1) of CT at funnel exit. The blue line represent 30% of maximum utilization (u=0,3) of bottom of the lubricator pipe in 300m WD.

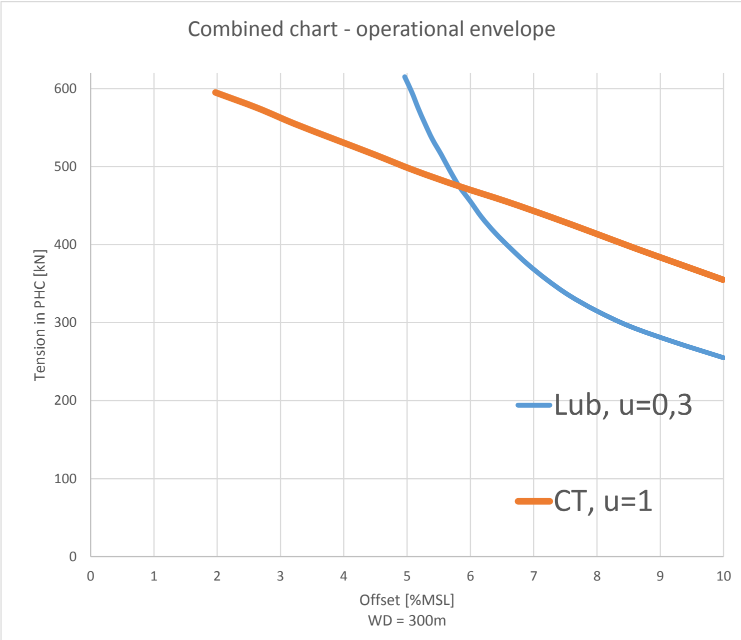


Figure 79 - 300m WD - Combined chart

14.2.3 100m WD vs. 300m WD comparison

The results from simulations at 100m WD and 300m WD are compared in Figure 80 for CT at funnel exit.

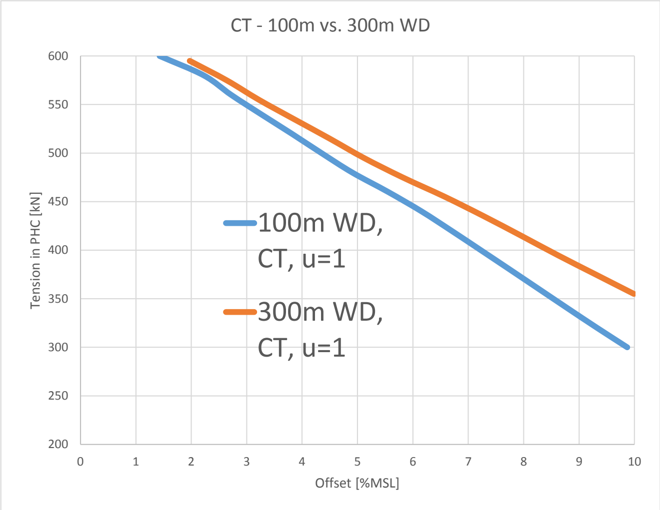


Figure 80 - CT - 100m vs. 300m WD

An estimate for the offset angle for both water depths was calculated in section 11.1. When the same offset (in %) gives different angle, the bending load will also be different. The angle in 300m WD (6,4º) is less than in 100m WD (8,5º), which means that a larger bending moment will be induced in 100m WD, such that the utilization of capacity is increased. The curves representing u=1 for both water depths are hence different form each other. Same principle goes for comparison of utilization in bottom of lubricator pipe as displayed in Figure 81 below. It is apparent that shallow water depths gives a reduced operating window.

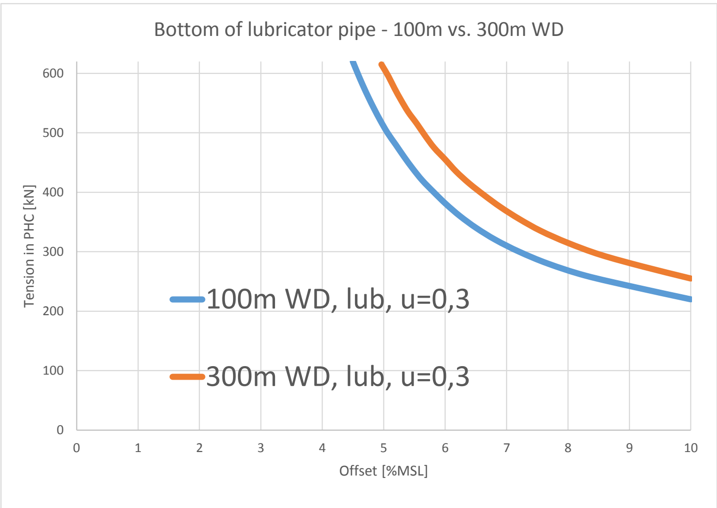


Figure 81 - Bottom of lubricator pipe - 100m vs. 300m WD

14.2.4 Procedure for establishing applied top tension

It is seen from the results that the applied tension in the PHC has a significant effect on utilization of the CT. The applied tension is therefore an important operation parameter that must be chosen with care. Several aspects of the system must be considered.

- **The CT at entering point into subsea stack must be kept in tension to avoid buckling of the tubing in the water column.**

The dotted line (2) in Figure 82 below shows that if insufficient tension is applied on top, the bottom of the CT will go into compression. There is then a high risk of damaging the CT in the water column due to buckling. The continuous line (1) illustrates the required top tension to keep zero effective tension at bottom. To account for dynamic tension variations due to e.g. vessel motion, a safety margin should be included such that tension is always present in the entire CT string.

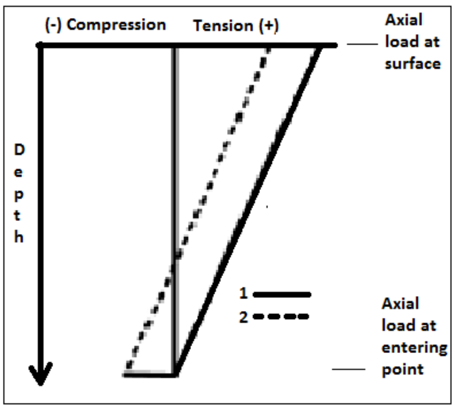


Figure 82 - Axial load profile of CT in water column

Naturally, the top tension required to avoid compression in the CT at bottom is water depth dependant. Deeper waters mean that higher applied top tension is required, because of the extra weight of the CT string. Figure 83 below is an illustration of this. The figure shows how the required top tension to keep effective tension at bottom zero, varies with water depth.

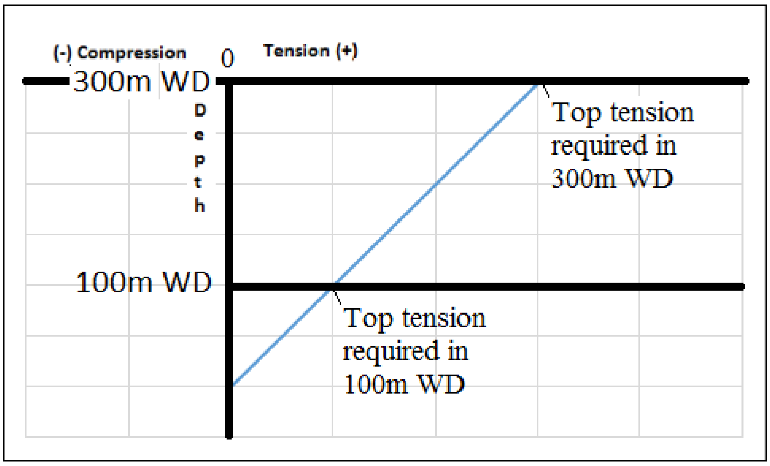


Figure 83 - Required top tension in 100m and 300m WD

- **The applied top tension in the CT must be kept below a safe working tension**

The maximum applied top tension is either limited by the structural capacity of the CT or the capacity of the topside equipment holding the CT (e.g. topside injector and heave compensation system). The tension in the CT is largest on top, but the subsea equipment from where the CT is grounded (e.g. subsea injector) must also be evaluated even if the tension here is reduced compared to the top. Since the CT will be relieved from the applied top tension when it enters the well, the weight of CT suspended in the well should also be considered here.

Given that the topside/subsea equipment has a larger capacity than the structural capacity of the CT, the CT will be the limiting factor.

- **Choosing the applied top tension**

The maximum and minimum limits are established. But this does not mean that any applied top tension in between is appropriate to use. By having a high applied top tension, the operating window is reduced because the utilization of CT is high. Consequences may for example be a reduced range of vessel offset or reduced max limit for wave height that otherwise may be acceptable for a lower applied top tension.

Operating circles (green, yellow and red zone) and timeframe for safe disconnect are key elements that must be established. Figure 84 below is an illustration of this. The size of the operating circles will be dependent on the utilization of CT, which increases with higher applied top tension.

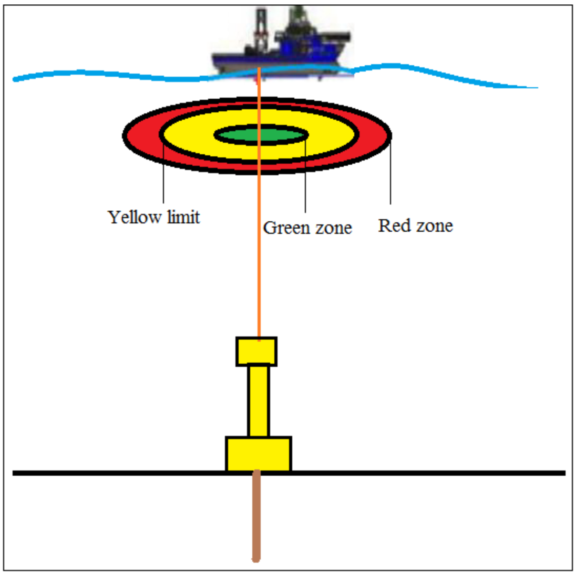


Figure 84 - Operating circles

As was expected, and as seen from the results, the bending moment in CT at funnel exit during a vessel loss of position increases with higher applied top tension, i.e. higher geometric stiffness. So not only will increased applied top tension give a higher utilization of the CT, it will also affect the development of other loads.

- **The applied tension should be as low as reasonably practicable.**

Another important factor to consider is the synchronization of the topside and the subsea injector; since both currently are manually operated, a considerable applied top tension might be wanted to avoid inaccuracy between the two injectors to become critical.

By summarizing the above factors a procedure can be made with reference to Figure 85:

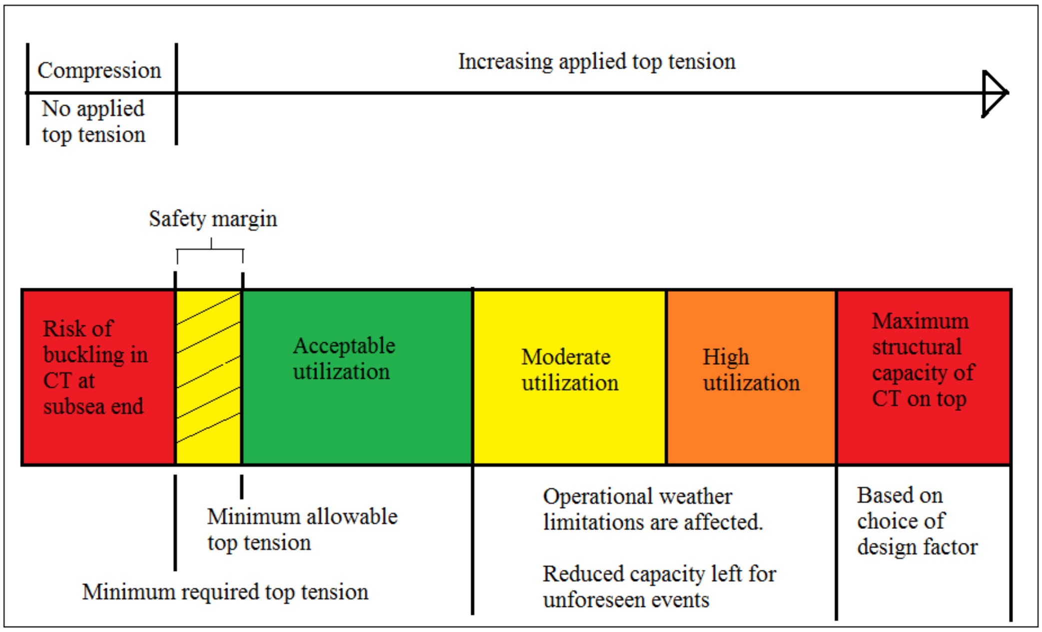


Figure 85 – Effect of applied top tension

1. Establish the minimum allowed top tension;
    a. Estimate the required top tension that gives zero effective tension at subsea end based on the relevant water depth
    b. Apply a safety margin. Dynamic tension variations must be accounted for. The safety margin should be sufficiently high such that any scenario within a specified probability range does not lead to compression in bottom of CT.
2. Establish the maximum allowed top tension
    a. Establish the structural capacity of CT (includes choice of design factor)
        i. Dynamic tension variations must also be accounted for here
    b. Check the capacity of equipment
    c. Check tensile limit of subsea stack and wellhead: in most (if not all) cases the CT will be the limiting factor, but a check should nonetheless be performed
    d. Establish dynamic tension limit. (According to API RP 16Q [33] the max tension for a riser should not exceed 90% of the dynamic tension limit. No such regulations exist for CT in open water)

3. Evaluate required tension to operate safely
    a. Establish an operational envelope showing maximum allowed offset as function of top tension for the relevant water depth (Check remaining compensator stroke as function of offset)
        i. Establish weather window
        ii. Establish operating circles
    b. Keep tension above safety margin
    c. Evaluate applied tension required for synchronization of topside pay-out and subsea end retrieval of CT
    d. Choose applied top tension

Establishing estimates for the operational weather limitations requires several conditions to be evaluated:

- The vessel position offset limit (drift off) must be evaluated for various water depths.
- Operating circles (green, yellow and red zone) and timeframe for safe disconnect are key elements that must be established.
- Handling of equipment on deck and inside tower during harsh weather (wind, waves)
- Simulation of disconnect scenarios (CT, umbilical) and stress/load calculations during these.
- Loads and stresses on WH and subsea stack
- Critical contact point – shearing between vessel system and subsea system
- Fatigue (high cycle, low cycle), coil life
- Vessel motion limits (e.g. pitch, heave)

14.3 Wave dynamics

14.3.1 Governing loads

Loads are expected to oscillate when waves are introduced. The bending moments at critical points in the system are of particular interest, since the effective tension will be more or less constant (there will be tension variations). Example from the model in 100m WD (load case #2); with an initial vessel offset of 5%MSL, the bending moment in CT at funnel exit as a function of time is seen in Figure 86 below. This is for the simulation with a wave period, T, equal to 7s. Remember that all simulations are performed with a wave height, H, equal to 7m.

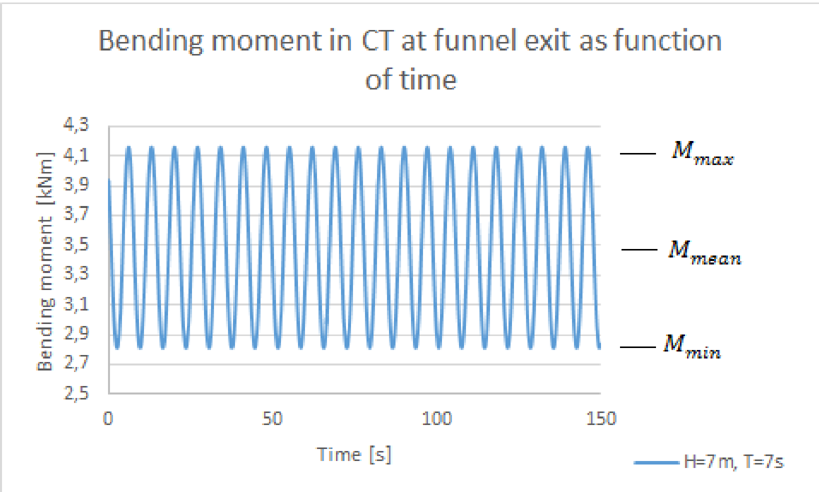


Figure 86 - Bending moment in CT at funnel exit as a function of time

The mean bending moment will be equal to the static bending moment, i.e. when no waves are present. Hence, the contribution from waves must be the dynamic bending moment amplitude (M_{dyn}) which is given by:

$$M_{dyn} = M_{max} - M_{mean}$$

where

M_{max} is the maximum bending moment;

M_{mean} is the mean bending moment.

By calculating M_{dyn} for all simulated wave periods, the dynamic bending moment can be plotted against wave period. This can in turn be compared to the vessel's motion, and since waves propagate towards the bow of the vessel, the vessel's pitch RAO is relevant. This procedure is repeated for the bottom of the lubricator pipe. Results are displayed in the next sections.

14.3.1.1 100m WD – load case #2

In Figure 87, the dynamic bending moment in CT at funnel exit and Island Constructor's pitch RAO is plotted against wave period. As seen from Figure 87, the dynamic bending moment can be said to be a function of the vessel's motion, and not a function of the loads imposed directly by the waves.

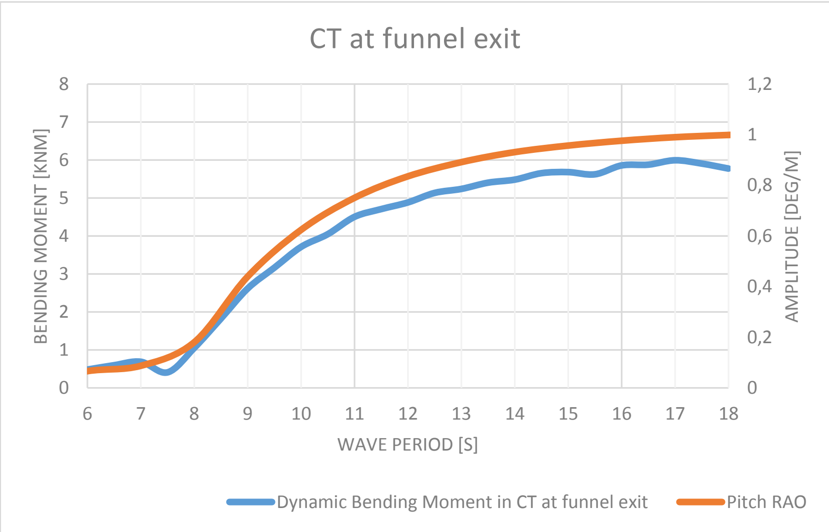


Figure 87 – 100m WD, Dynamic bending moment vs. pitch RAO - CT at funnel exit

Figure 88 below displays the dynamic bending moment in bottom of the lubricator pipe together with the vessel's pitch RAO plotted against wave period. It is here clearly seen that wave loads with a wave period around the natural period of the combined system excites resonance, i.e. the wave loads dominate the dynamic response in the subsea stack. The natural period for the whole system (subsea stack and CT) was found to be 7,51s for mode 1 in the modal analysis conducted in section 12.2. From Figure 88, it is seen that the dynamic bending moment is highest for the waves with a period of 7s, which coincides considering that hydrodynamic drag and other non-linear effects not are accounted for in the modal analysis. These are, however, present in the system during a simulation and will have a dampening effect.

If the system was without damping, the loads at the period of resonance could be extremely high.

Remember that the wave periods were varied in steps of 0,5s for each simulation. As a consequence, the peak load may be hidden in the wave periods not simulated with, i.e. between 7 and 7,5s.

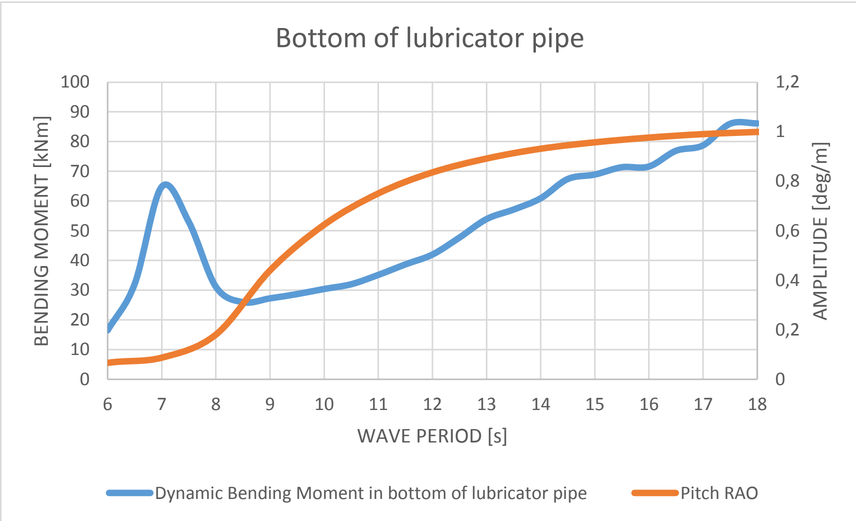


Figure 88 – 300m WD, Dynamic bending moment vs. pitch RAO - bottom of lubricator pipe

14.3.1.2 300m WD – load case #5

The dynamic bending moment in CT at funnel exit and the vessels pitch RAO is plotted against wave period in Figure 89.

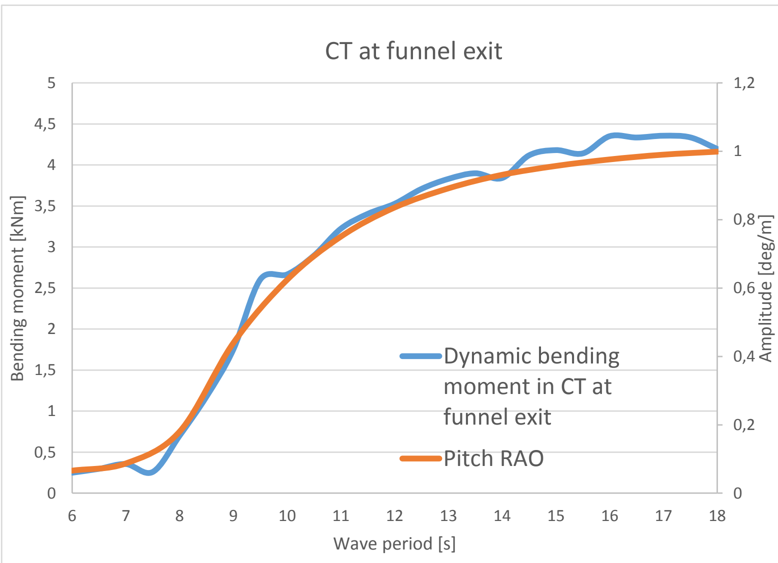


Figure 89 - 300m WD, Dynamic bending moment vs. pitch RAO - CT at funnel exit

Figure 90 displays the dynamic bending moment in bottom of the lubricator pipe together with the pitch RAO, plotted against wave period.

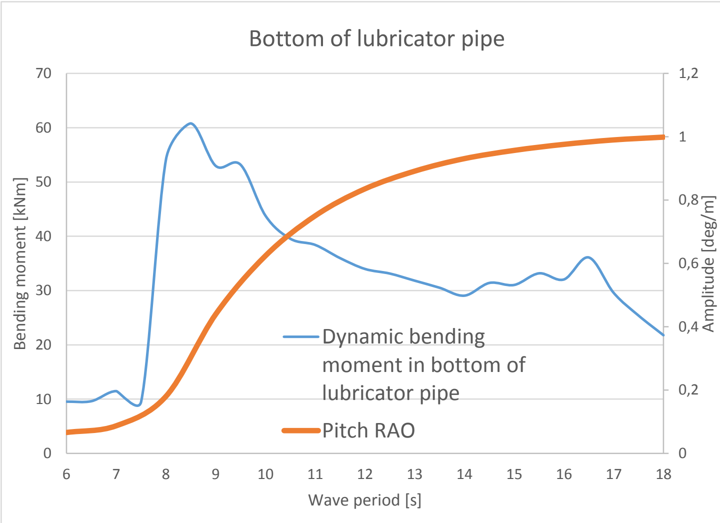


Figure 90 - 300m WD, Dynamic bending moment vs. pitch RAO – bottom of lubricator pipe

The same effects as for the model in 100m WD are present here. See section 14.3.1.1 for explanation. However, the bending moment is far more reduced in 300m WD. A comparison of capacity utilization follows in the next section.

14.3.1.3 Comparison of 100m WD and 300m WD

Seeing that the effects were similar in 100 and 300m WD, it was relevant to investigate the effect of the difference in bending moment on utilization of CT and bottom of lubricator pipe. The maximum bending moment is then extracted from Orcaflex (the dynamic bending moment is only the amplitude). Utilization at the two hotspots in 100m WD is shown below in Figure 91.

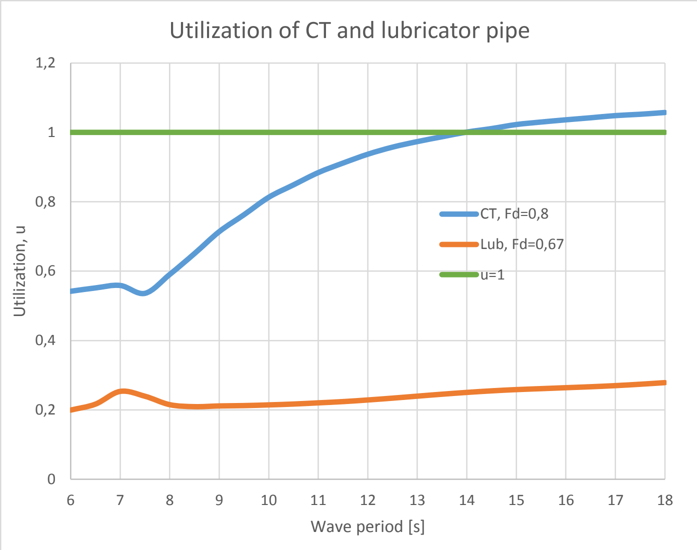


Figure 91 – 100m WD - Utilization of CT and lubricator

In Figure 91 it is seen that utilization of CT at funnel exit reaches u=1 when T=14s. Remember that the vessel is not located directly above the well in these simulations, but has an offset of 5%MSL, such that the bending moment is not only a result of the waves being present.

Figure 92 below shows the associated utilization in CT and lubricator in 300m WD. Even though the effective tension will be higher at funnel exit in 300m WD, the utilization will be lower than in 100m WD due to the reduced bending moment. It is seen that the CT string never reaches u=1. Hence, the same vessel offset in %MSL gives reduced loads in 300m WD compared to 100m WD. This is because the offset angle is larger in 100m WD due to the length of the subsea stack (see section 11.1 and 14.2.3).

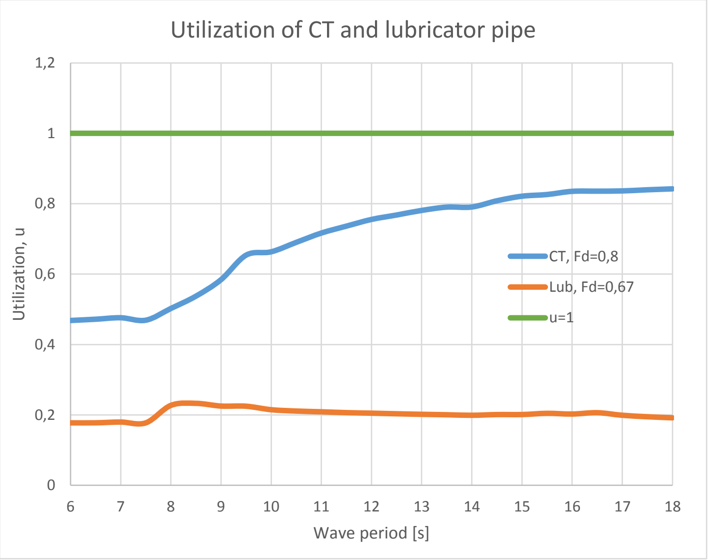


Figure 92 - 300m WD - Utilization of CT and lubricator

14.4 Current

The objective with load case #3 was to investigate the effect on bending moment for downstream and upstream vessel offset conditions. Hence, it is a sensitivity analysis easily performed by extracting the bending moment directly from simulations performed in Orcaflex. As specified in load case #3, two simulations were performed. The current direction was varied (0 and 180 degrees) for the sake of comparison.

Since the shape of the CT will change (depending on current speed), the bending moment in CT at funnel exit and at entrance into the SSI is expected to vary with different current direction. The values for the bending moment were thus extracted as a function of offset at both points for both simulations. The results are presented in the next section.

14.4.1 Offset in upstream vs. downstream direction – load case #3

Figure 93 displays how the bending moment changes in the CT at funnel exit and at entering point at SSI with an offset in upstream vs. downstream direction. The simulated vessel offset for the current direction of 180 degrees, i.e. offset upstream, is given negative values in primary X-direction.

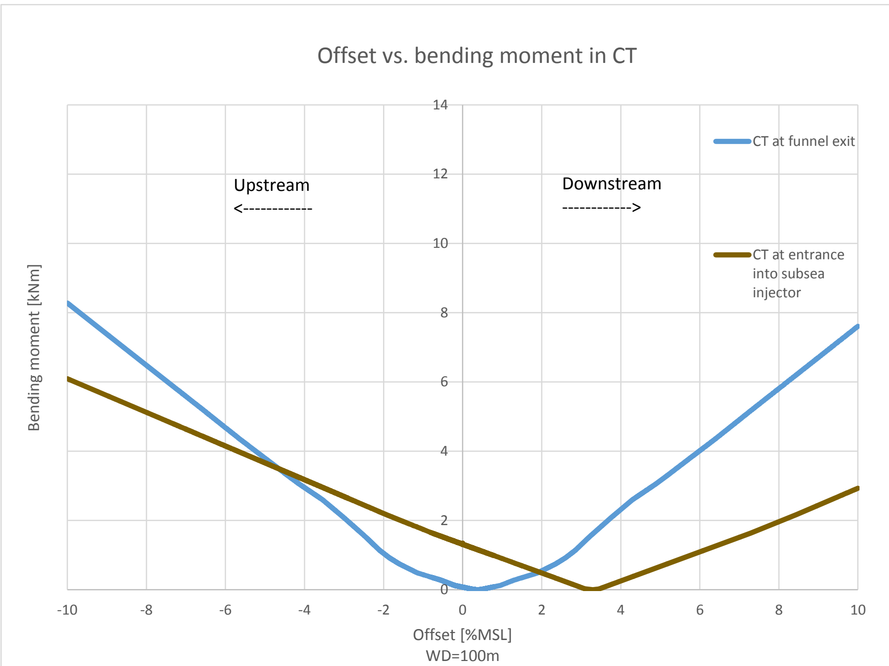


Figure 93 - Bending moment as function of offset in upstream vs. downstream direction

A vessel offset upstream will impose the largest bending moments on the CT, both at funnel exit and at entering point into SSI. This is due to the induced shape of the CT in the water column (see Figure 54 in section 12.1.3).

Upstream vs. downstream

The reduction in bending moment in CT at SSI is far more reduced than in CT at funnel exit. When the vessel is positioned directly over the well, the subsea stack will have an initial curvature due to the constant force applied by current, i.e. the drag force. Figure 94 displays the initial curvature about the Y-axis at different lengths in the subsea stack (0m is bottom) for both current directions.

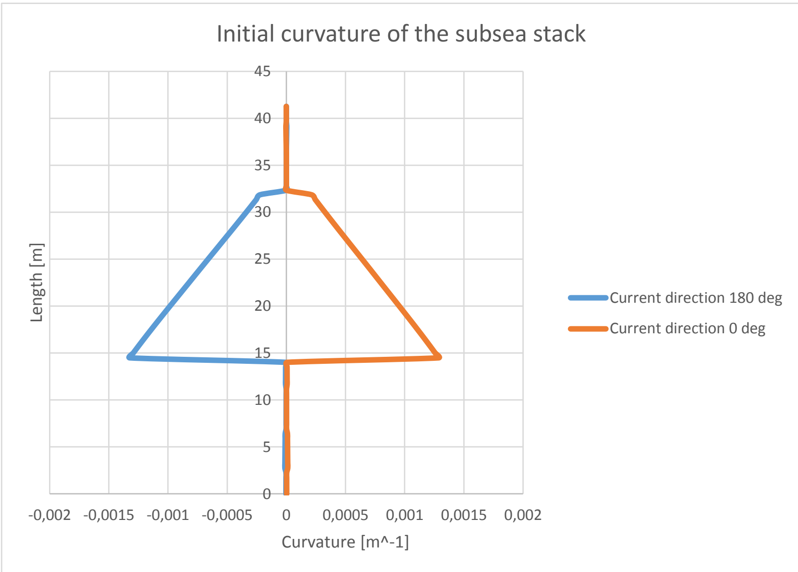


Figure 94 - Initial curvature of the subsea stack

As the vessel moves, the initial curvature will be superimposed on the extra induced curvature due to the offset. Hence, for a vessel offset in upstream direction (180 degrees), the subsea stack will curve less as Figure 95 below shows.

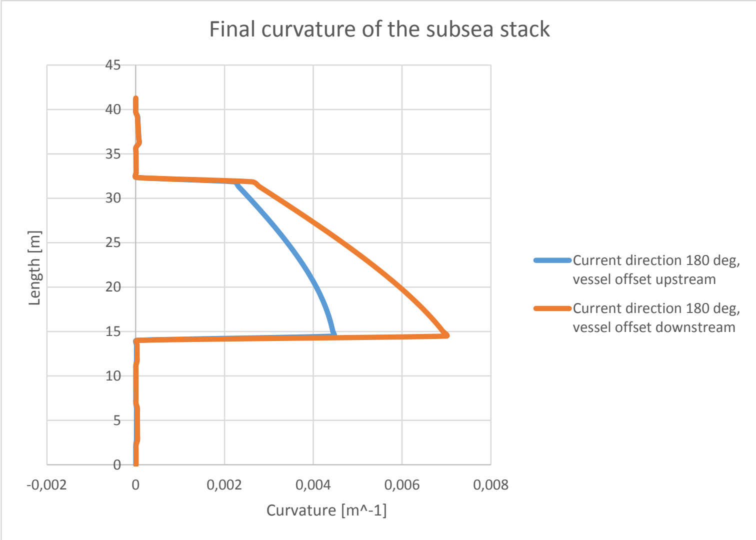


Figure 95 - Final curvature of the subsea stack

Figure 95 shows the curvature of the subsea stack when the offset is 10m. The subsea stack will have a larger curvature with an offset downstream, as both tension and drag force is working in the same direction. When the vessel has an offset upstream, the current-induced drag force will be working in the opposite direction of the tension in the subsea stack. The CT leaving the SSI will then therefore have a larger departure angle compared to a vessel offset downstream, and will thereby experience a larger bending moment as seen in Figure 93. The bending moment in CT at funnel exit is not noticeably affected by the curvature of the subsea stack, but is a consequence of the altered shape of the CT in the water column due to the drag force, i.e. the departure angle changes.

The applied tension in the PHC will naturally also have an effect on the shape of the CT in the water column. This is not investigated.

15. Considerations & discussion

15.1 Considerations

The CT string after being reeled off the reel and onto the gooseneck has undergone plastic strains and may have residual internal stresses as it leaves the topside injector because of the repeated bending cycles. The CT in open water has then already been exposed to loads beyond yield. Plastic straining of steel may change the material properties such that the elastic limit and the ultimate capacity are reduced. Hence, ISO 13628-7 cannot accurately be used for a coiled tubing string in open water, as it does not take these effects into account. No regulations or standard includes the full aspect of CT in open water. A unified analysis method that includes strain softening, strain hardening or accumulated plastic strain would be a first step towards more accurate CT load estimates for OWCT.

15.2 Discussion

To assess operating limits in an OWCT system consisting of several components, it is important to identify the weaker parts of the system.

In this specific modelled OWCT system it is evident that the CT is the weak link. However, the size of the CT string plays a significant role here. A CT string with a higher structural capacity[2] or a reduced structural capacity of the lubricator could change this conclusion for different OWCT system setups. Figure 96 is an illustration of this.

- The bottom orange curve represents maximum utilization of CT at the weakest point (CT at funnel exit based on the presented work in this thesis) and is the dimensioning curve in Figure 96
- The top blue curve represent the maximum utilization at a weak point in the subsea stack (bottom of lubricator based on the presented work in this thesis)

If the blue curve where to intersect the orange curve at a point, the bottom of the lubricator would be dimensioning, i.e. represent the weak point in the system.
Since there is a possibility for that a subsea stack component for a certain system configuration will represent the weak point in the system, it can thus <u>not</u> be concluded based on the present work that the CT string will always be the weak link in all OWCT systems.

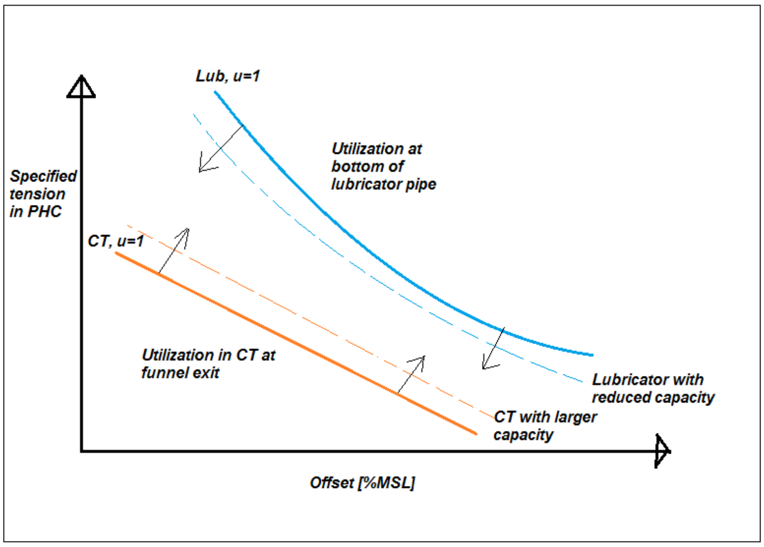


Figure 96 - Utilization of CT string and lubricator – discussion

[2] E.g. larger outer diameter or wall thickness or different steel type

It looks beneficial to ensure that the CT is the weak link. Well barrier integrity is of concern should a component in the subsea stack fail. A CT string can easily be replaced if damaged.

A simplified version of Island Offshore Subsea's OWCT has been modelled and analysed in this thesis. Based on the present work it appears to be a feasible concept. A few positive remarks are thus made:

- A subsea injector (and its position in the subsea stack) is crucial to maintain a safe tensioned heave configuration during the operation.

The subsea injector resides as the uppermost component in the subsea stack during an operation in this concept. During installation, the SSI is lowered down on two guide wires together with the stripper and the toolstring. As soon as the SSI is latched onto the subsea stack (toolstring in lubricator), the CT string can immediately be controlled by the gripper blocks in the SSI. For several purposes, this is a very good thing. Compared to a subsea injector located below the lubricator (as in other OWCT concepts), a lot of additional equipment to control the CT and toolstring are then avoided. By pulling the SSI together with the toolstring between runs, there is in addition the ability to inspect the equipment.

- **A note for consideration:** Assuming that the CT string is the weak link in the system, there is the possibility that a technical failure could cause the two injectors to pull in different directions.

One of the injectors should thus be pre-set to a maximum capacity pull, which will ensure that the CT string will slip through the gripper blocks in the injector in case of an accidental scenario. As a recommendation; the pre-set capacity for the topside injector should be less than for the subsea injector, and also less than the structural capacity of the CT string. The subsea injector should be able to handle a greater pull considering a case where a long CT is suspended in the well. In light of the above consideration: Manual synchronization of the two injectors may prove to be a reasonable solution.

- Accidental scenario: A DP failure in shallow waters resulting in a vessel loss of position.

A mitigation procedure proposed by IOSS was to reel out the CT string to avoid rupture of the CT string. An illustration is shown below in Figure 97.

However, by doing so, the CT string may experience a large bending moment at entrance into SSI. Based on the present work, the funnel located topside resulted in reduced bending moment in the CT string compared to when no funnel was present. Maybe a subsea funnel[3] located above the SSI could be included if this emergency procedure is approved in an accidental scenario?

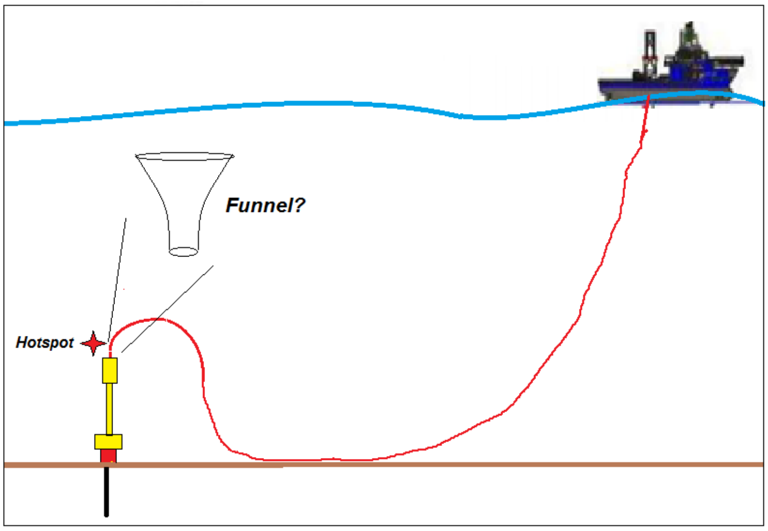


Figure 97 – Accidental scenario

[3] The subsea funnel should naturally not have the same dimensions as the topside funnel. Considering the shape of the CT in the described accidental scenario the radius of curvature of the subsea funnel could be similar to as for a gooseneck.

16. Conclusions

Numerous model scenarios have been designed to point out potential limits and operational ranges. The conclusions can be divided into:

- General conclusions
- Model specific conclusions

16.1 General conclusions

Applied top tension plays a significant role for operating limits in an OWCT system. Both excessive and inadequate applied top tension has a negative effect on the CT string, which in turn may result in a reduced operating window. As opposed to a workover riser, the CT string has limited structural capacity in terms of tensile force. If the heave compensation system were to fail in an emergency situation, the following increase in tension could be disastrous for the CT string. The applied top tension is therefore a critical operation parameter in an OWCT system. To achieve a larger operating window, the applied top tension during an operation should be as low as possible, but be sufficient to ensure positive effective tension in the entire CT string.

Water depth has a significant impact on operational limitations for an OWCT system. All simulations signal that shallow water depths reduce the operating window. There is a minimum water depth limitation for an OWCT operation. Based on the present work, this is governed by the distance between vessel and top of subsea stack. At some point, the inclination angle of the CT would become too large even by the slightest vessel offset.

16.2 Model specific conclusions

The lubricator is the weak link in the subsea stack, but is not the weak link in the OWCT system. The CT string itself is the weak link in the system.

During a vessel loss of position, the modelled funnel/bellmouth had the effect of reducing the bending moment in the CT string. The funnel may thus be a key factor in determination of operational weather limitations for an OWCT system.

Prior to the simulations with waves, a modal analysis was performed to identify possible resonance dynamics, i.e. natural periods. In the range of wave periods that were simulated with (6-18s), only the natural period of mode shape 1 was included for both water depths. Based on the present work, it can be concluded that excitation of resonance in the system does not have a significant effect on the loads in the CT for the simulated sea states. The loads in the CT are governed by the vessels motion and not the direct impact load from waves. In opposition, wave loads govern the dynamics in the subsea stack for the simulated sea states, but does not considerably affect the structural integrity in terms of utilization at its weakest point. Excitation of resonance may give higher loads in the CT for other modes (e.g. mode 2 or 3). The results indicate that shallow water depths reduce the operating window in harsh weather.

Simulations with current proved that a vessel loss of position upstream is more critical than a loss of position downstream in terms of loads at CT end points. A vessel loss of position in upstream direction may only transpire if the DP system malfunctions, i.e. it is a drive-off.

17. Future work

- Availability: A wave scatter diagram can be used to establish operational weather limitations with regards to sea states. An estimate of the availability can thus be made by using weather conditions from a specific field.
- Results from the modal analysis revealed that most modes had a natural period under 6 seconds. When simulating with regular waves, the possibility for such short wave periods to occur is dependent on the wave height. For a wave height representing a size to that of an operational limit, it is very unlikely that such short periods will have any significant wave energy. On the other hand, if irregular wave theory was used (e.g. JONSWAP), one would be able to decompose the frequency content, and probably find that some high frequencies (short periods) would be present that may excite the modes with lower natural periods. A study with irregular waves could thus be pertinent.
- Investigate the effect of varying the weight representing CT suspended in well. A large weight of CT in well provides increased compression in the subsea stack. This may have an effect on load estimates in the subsea stack.
- Investigate the load condition when subsea injector, stripper and toolstring are installed running on two guide wires (suspended)
- Fatigue/cyclic loading have a significant impact on CT load estimation. A fatigued CT will have reduced structural capacity. A study on fatigue of CT in open water would increase accuracy of load estimates of CT in open water.
- Investigate the relationship between utilization of CT and subsea stack components by varying CT and subsea stack dimensions. A potential intersection point could be of great value for future OWCT concepts.
- The modelled funnel in this thesis plays an important role in the development of bending moment in the CT string. Optimized funnel dimensions could have a significant effect on operational weather limitations in an OWCT system, and could further contribute to increased availability.
- Investigate moonpool boundary conditions.

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Appendix A

Riser stroke is affected by various sources including:

- *Riser top set-down due to vessel offset and current-generated riser sagging.*
- *Dynamic riser deflections.*
- *Vessel motions.*
- *Tidal variations.*
- *Vessel draught variations.*
- *Riser elongation due to temperature, pressure and tension.*

The methods used to accommodate these effects and maintain reasonably constant riser tension are (somewhat imprecisely) denoted "heave compensation". The stroke that can be accommodated is typically determined as the minimum of the following stroke capacities:

- *Riser tensioner stroke*
- *Travelling block heave compensator stroke*
- *Riser wear/slick joint stroke margins up and down*
- *Surface flow tree stickup above drill floor*
- *Distance between drill floor and flexible hose connected to SFT/WLA and standpipe*

If the available heave compensator stroke capacity is used to compensate for riser set-down, there is no capacity left for vessel heave motion. Conversely, if the vessel heave range is close to or equal to the compensator stroke range, there is no surplus length to provide for riser set-down. The ultimate consequence is stroke-out, which will usually cause a large increase in riser tension. The stroke-out may result in parting of the riser or damage to subsea well. Shallow water and high vessel offset are usually the most critical conditions.

The heave compensator should be operated with the mean position close to mid-stroke. It can be manually adjusted for tidal variations and other controlled, planned or observed elongation of the riser string.

The riser stick-up above drill floor (distance from, for example, surface flow tree or other large diameter snag points to drill floor) must also be considered. After connected to the seabed, there are limited means of adjusting for time varying stick-up (apart from disconnecting and adjusting the riser makeup or ballasting/deballasting the rig). Consequently, the riser stick-up must be planned to accommodate all effects that may reduce the margins to accommodate up/down heave motions.

In addition to dynamic vessel heave, some quasi-static effects should be considered. The following effects should be considered:

- *Tide*
- *Storm surge*
- *Riser makeup tolerance (the tolerance is equal to half the length of the shortest pup-joint available)*
- *Riser top set-down due to vessel offset and current*
- *Elongation of riser due to temperature, pressure and tension*

Figure 98 illustrates the limitations tied to stroke capacity.

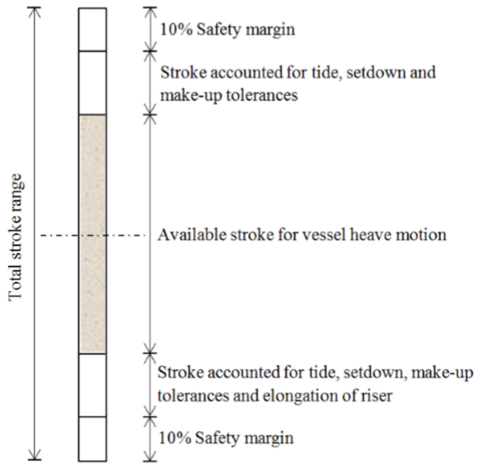

Figure 98 - Stroke capacity limitations

Appendix B

Values are rounded to the nearest whole number. The values are taken from static simulations.

Table 27 - 100m WD - Effective tension in CT

100m:

Specified tension in PHC [kN]	Effective tension in CT at funnel exit [kN]	Effective tension in CT entering SSI [kN]
160	12	6
180	32	26
200	52	46
220	72	66
240	92	86
260	112	106
280	132	126
300	152	146
320	172	166
340	192	186
360	212	206
380	232	226
400	252	246
420	272	266
440	292	286
460	312	306
480	332	326
500	352	346
520	372	366
540	392	386
560	412	406
580	432	426
600	452	446
620	472	466

Table 28 - 300m WD - Effective tension in CT

300m:

Specified tension in PHC [kN]	Effective tension in CT at funnel exit [kN]	Effective tension in CT entering SSI [kN]
175	27	6
195	47	26
215	67	46
235	87	66
255	107	86
275	127	106
295	147	126
315	167	146
335	187	166
355	207	186
375	227	206
395	247	226
415	267	246
435	287	266
455	307	286
475	327	306
495	347	326
515	367	346
535	387	366
555	407	386
575	427	406
595	447	426
615	467	446

Table 29 - 100m WD - Effective tension in bottom of lubricator pipe

100m	Bottom of lubricator pipe - 100m WD
Specified tension in PHC [kN]	Effective tension/compression [kN]
160	-210
180	-190
200	-170
220	-150
240	-130
260	-110
280	-90
300	-70
320	-50
340	-30
360	-10
380	10
400	30
420	50
440	70
460	90
480	110
500	130
520	150
540	170
560	190
580	210
600	230
620	250

Table 30 - 300m WD - Effective tension in bottom of lubricator pipe

300m	Bottom of lubricator pipe - 300m WD
Specified tension in PHC [kN]	Effective tension/compression [kN]
175	-211
195	-191
215	-171
235	-151
255	-131
275	-111
295	-91
315	-71
335	-51
355	-31
375	-11
395	9
415	29
435	49
455	69
475	89
495	109
515	129
535	149
555	169
575	189
595	209
615	229