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Reliability Assessment of Subsea X-mas Tree Configurations

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Preface

This work is my master thesis. This was done at the Department of Production and Quality Engineering at the Norwegian University of Science and Technology (NTNU) as a part of the study program Subsea Technology. It was written during the spring semester 2015.

The thesis has been guided and supervised by Professor Marvin Rausand and Professor Anne Barros at the Department of Production and Quality Engineering at NTNU.

During the writing of this thesis some help and guidance have been provided by Endre Willmann working with technical assurance at GE Oil & Gas.

The reader of this report should have a basic understanding of oil and gas production in a subsea production system. The reader should also have an understanding of reliability and reliability analysis.

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Acknowledgment

I would like to thank my supervisor Professor Marvin Rausand for his help during the writing of this thesis. He retired one month before submission, but provided very helpful guidance and support before that.

I would also thank Endre Willmann at GE Oil & Gas and Professor Anne Barros at NTNU for their input.

P.G.W.

Executive Summary

The focus of this thesis is to provide input for choosing the optimal X-mas Tree (XT) configuration for a subsea production system.

The subsea XT is used to direct, regulate, and stop the flow from a well. These functions and some more are achieved through several valves, a subsea control module, and some sensors.

The choke valve has the worst inherent reliability of the components on a XT. Because of this the choke valve is designed for easy retrieval. The choke valve could also be placed in a separate flow control module. The subsea control module is the XT component with the second worst reliability. Both these components are modules because it is good method of improving system maintenance of unreliable components.

The main XT configurations are the vertical XT, the horizontal XT, and the deepwater vertical XT. The main differences are how the main valves are placed and how the tubing with tubing hanger is installed.

In subsea reliability it is common to use mean time to failure as a performance indicator and the exponential distribution to model lifetimes.

A Reliability, Availability, and Maintainability (RAM) analysis is frequently used to analyze the subsea production system. RAM analysis software use reliability block diagrams, flow diagrams, and Monte Carlos next event simulation to simulate the lifetime and the availability of the subsea production system.

Two main sources of reliability data for subsea components are OREDA (2009) and Molnes and Strand (2007). When applying component reliability data in a RAM analysis, this often give a lower availability than experienced in real life. This could relate to how, from when, or from where the data are collected. Expert judgment can be used to calibrate the data so that the model fit the real life scenario. The sensitivity and uncertainty of assumptions and the analysis should also be considered. The model and analysis can then be used to optimize the reliability of the design.

In OREDA (2009) the vertical XT has a lower inherent reliability than the horizontal XT. The low reliability may relate to the large share of older generation vertical XTs installed. Understanding the quality of the data is difficult and decisions should not be taken solely on the basis

of unprocessed data.

A key difference between the XT configurations is the maintainability of the tree and the tubing. Wells that are expected to have many tubing failures should be equipped with a horizontal XT and a vertical XT should be on a well with few tubing failures. This is mainly due to the order of which the components are installed as the HXT allows the tubing to be retrieved without retrieving the tree and vice versa for the VXT.

A failure on the wellhead connector will have a large impact on the availability. Interventions on the horizontal XT are done with a blowout preventer. The height of both these components puts more strain on the wellhead than the other XT configurations. Tripping out tubing is one of the more dangerous operations in a well; this combined with the extra strain on the wellhead may cause bad consequences. This may give an advantage for the VXT in a risk perspective.

A horizontal XT with a flow control module will have improved maintainability, but this adds potential leak paths and makes the design more complex. The vertical XT and deepwater vertical XT are easier to retrieve and may be better off with a simpler design without the flow control module.

The deepwater vertical XT is easier to maintain than a vertical XT. It may be a good choice of configuration for wells with a medium amount of tubing failures. The DVXT is more complex and has more leak paths than the other two configurations and may have a higher infant mortality because of this.

OneSubsea (2015) help their customers choose XT configuration with a tree selector tool. Ranking the importance of different aspects give an output of how the XT configurations fit this ranking. This gives a good indication of which configuration to choose for a well.

CAPEX and OPEX are important factors in the decision process.

A RAM analysis would give an overall look on the reliability and life cycle cost of the subsea production system. RAM analysis software is able to process the many varying factors that impact the optimal XT configuration for a subsea production system and should be the foundation of the decision process.

Sammendrag

Fokus for denne masteroppgaven er å optimalisere valg av juletre konfigurasjon for et undervanns petroleums produksjons system.

Et undervanns juletre leder, regulerer og kan stoppe en brønn. Disse funksjonene og noen til gjøres a flere ventiler, en kontroll modul og noen sensorer.

På et juletre er strupeventilen komponenten med dårligst pålitelighet. Derfor er den designet for og lett kunne bli erstattet. Strupeventilen kan også bli plassert i en egen flyt kontroll modul. Undervanns kontroll modulen er juletre komponenten med nest dårligst pålitelighet. Plassering av upålitelige komponenter i moduler er en god metode å forenkle vedlikehold.

De tre konfigurasjonene av juletrær er vertikale, horisontale og dypvanns vertikale juletrær. Hovedforskjellen er hvordan ventilene er plassert og hvordan tubing og tubing hengeren er installert.

I pålitelighet på undervanns komponenter er den vanligste ytelsesindikatoren gjennomsnittlig tid til feil (Mean Time To Failure) og den vanligste livstid modellen er eksponential fordelingen.

En pålitelighet, tilgjengelighet og vedlikeholdsvennlighet (RAM) analyse er en vanlig måte å analysere et undervanns produksjons system. En RAM analyse bruker pålitelighets blokk diagram, flyt diagram og Monte Carlo neste hendelse simulering for å simulere livsløpet og tilgjengeligheten til et undervanns produksjons system.

To kilder til pålitelighets data for undervanns komponenter er OREDA (2009) og Molnes and Strand (2007). Når komponent pålitelighetsdata blir brukt i en RAM analyse kan det gi en lavere systemtilgjengelighet enn i virkeligheten. Dette kan stamme fra hvordan, fra når og fra hvor dataen er innhentet. Ekspertvurderinger kan bruker til å kalibrere dataen sånn at modellen blir mer lik virkeligheten. Usikkerheten og sensitiviteten til antagelsene burde være vurdert. Modellen og analysen kan så brukes til å optimere påliteligheten til et design.

Det vertikale treet har i OREDA (2009) en lavere pålitelighet enn det horisontale treet. Den lavere påliteligheten kan stamme fra den store andelen av eldre vertikale trær som er installert. En god forståelse av kvaliteten av dataen er vanskelig, derfor burde beslutninger ikke tas bare på grunnlag av slik data.

En viktig forskjell på juletre konfigurasjonene er hvor vedlikeholds vennlig treet og tubingen er. Brønner som forventes å ha mange tubing feil burde ha horisontalt trær og vertikale trær burde være på brønner som forventer få tubing feil. Dette kommer fra rekkefølgen tubing og tre blir installert i siden det horisontale treet tillater at tubingen kan trekkes uten at treet trekker og motsatt for vertikale trær.

En skade på brønnhodekoblingen vil ha en stor påvirkning på tilgjengeligheten. Intervensjoner på horisontale trær gjennomføres med en utblåsningsventil på toppen av treet. Høyden av disse komponentene utgjør større krefter på brønnhodet enn hos de andre juletre konfigurasjonene. Utkjøring av tubing er en av de farligste aksjonene i en brønn; dette kombinert med ekstra krefter på brønnhodet kan føre til dårlige konsekvenser. Dette kan gi en fordel til det vertikale treet i et risiko perspektiv.

Et horisontalt tre med en flyt kontroll modul vil ha en forbedret vedlikeholds vennlighet, men modulen gir flere potensielle lekkasjeveier og gjør designet mer komplekst. Det vertikale og dypvanns vertikale treet er lettere å ta opp for vedlikehold og kan være bedre tjent med et enklere design uten flyt kontroll modulen.

Dypvannstreet er enklere å vedlikeholde enn det vertikale. Det kan være et godt valg av konfigurasjon for brønner med et medium antall tubingfeil. Dypvannstreet har et mer kompleks design med flere lekasjeveier enn de andre to konfigurasjonene og kan ha en høyere initiell feilrate på grunn av dette.

OneSubsea (2015) hjelper kundene sine med å velge juletre konfigurasjon med et eget verktøy. Rangering av viktigheten til forskjellige aspekter gir et resultat med hvordan hver av de tre konfigurasjonene passer til denne rangeringen. Dette gir en god indikasjon for hvilket valg som er best for brønnen.

Innvesterings og operasjonskostnader er viktige faktorer i valget av konfigurasjon.

En RAM analyse vil gi et overblikk på påliteligheten og livstidskostnadene til et undervanns produksjons system. En data RAM analyse kan prosessere de mange variablene som påvirker den optimale juletre konfigurasjonen for et undervanns produksjons system og burde være grunnlaget i en beslutningsprosess.

Contents

Chapter 1

Introduction

1.1 Background

The number of subsea production systems has increased a lot since 1990 (Bai and Bai, 2012). *"The market will see orders for over 3,000 new subsea trees through 2017 (>60% growth from 2008-2012). Deep and ultra deepwater subsea demand is expected to increase by 90% through 2017 compared to the previous five years"* (Quest Offshore, 2013).

Oil and gas development is also being explored in the arctic. Due to ice and icebergs, subsea production systems are the only viable methods in some areas. This would require very reliable and safe systems due to the inaccessibility during the winter, both for maintenance and mitigation of a potential blowout. The arctic ecosystem is fragile and an oil spill could have a large impact. Safe and reliable subsea production systems will therefore become more and more important.

The Åsgard subsea field on the Norwegian Continental Shelf has a lifetime of 20 years, some parts up to 40 years. The equipment is therefore designed for 20 years or 30 years (Østebø et al., 2001).

For a subsea oil and gas field repair and intervention are expensive due to unavailability of the production and mobilization times for vessels. Therefore the lost production and intervention costs are a big part of the life cycle cost of a subsea well (Brandt and Eriksen, 2001).

The subsea X-mas Tree (XT) is an essential part of a subsea production system. There are lots of possible configurations and equipment provided from different suppliers. The XT comes in different variants and often requires detailed engineering for each project. With the decrease in the oil price the last year there is an increased demand for standardized solutions.

The main companies supplying subsea XTs are FMC Technologies, Aker Solutions, OneSubsea, and GE Oil & Gas, market share in that order (Quest Offshore, 2013). Oil producing companies come to the suppliers with an increased focus on reliability and standardized products. Therefore it is important to both the oil companies and the suppliers to have a good understanding of the XT configurations and what the best solution for a specific field is.

The overall reliability of XTs is mostly not a big problem; the interesting part is the difference in reliability between the main configurations of XTs which is the focus of this master thesis.

In this thesis there are two main sources of information on XTs that overlap to some extent. Most references are made to Bai and Bai (2012) because this is the most recent. Similar information can also be found in Richbourg and Winter (1998). Golan and Sangesland (1993) is a third even older source has also provided some useful information on the XT.

Previously a master thesis has addressed the reliability of the deepwater vertical XT from GE Oil & Gas (Stendebakken, 2014). The thesis focus on a single tree and its retrieval rate, this thesis has been used as a source for reliability data and description the deepwater vertical XT from GE.

The main source on the topic reliability is Rausand and Høyland (2004). Reliability data are taken from OREDA (2009) and Molnes and Strand (2007). Terminology definitions are often taken from the vocabulary database IEV Online (2015).

1.2 Objectives

The main objectives of this Master's thesis are:

1. Carry out and document a literature survey related to subsea x-mas trees.

2. Describe the main functions of a subsea x-mas tree and the reliability of its main components.

3. Describe the differences between the main subsea x-mas tree configurations and how these affect the reliability of the subsea production system.

4. Evaluate the reliability data and models that are used to assess the reliability of subsea x-mas trees.

5. Carry out and document a reliability assessment with focus on the differences between the main subsea x-mas tree configurations.

6. Describe and evaluate what should be assessed when selecting a x-mas tree configuration for a new subsea well.

1.3 Limitations

In this report only wet subsea x-mas trees are discussed. Any reference to x-mas trees or the acronym XT refers to subsea x-mas trees.

The variations of a subsea production field and XTs are endless; it will be difficult to consider every variation in detail. In this thesis there is a broad focus on XTs for both oil and gas production. Injection trees are mostly disregarded. Broader concepts of the XT are discussed rather than the detailed engineering. Water depth, temperature, pressure, and bore size are only considered in a broad context.

"Subsea wells can be classified as either satellite wells or clustered wells" (Bai and Bai, 2012). Satellite wells are more independent than clustered wells that share more functions. This thesis only considers the clustered wells; however, the difference in small. Clustered wells can be put on a common template but also this is not considered.

There is limited literature on XT reliability available. This is due to the competition that exists between the XT suppliers. The XT is also one of the safer and field proven parts of the subsea production system. This has limited the open research available on XT reliability.

1.4 Approach

Objective 1, 2, and 3 is achieved through a literature survey on XTs. Objective 4 is achieved through a literature survey on the quality and collection of reliability data.

A qualitative reliability system analysis is conducted to achieve objective 5. Objective 6 is achieved partially through the reliability analysis and partially through a literature survey.

1.5 Structure of the Report

The rest of the report is organized as follows:

Chapter 2 gives an introduction to a x-mas tree's functions, components, component reliability, and the main configurations.

Chapter 3 introduces reliability and reliability analysis.

In Chapter 4 a qualitative reliability analysis of the x-mas tree configurations is conducted.

Chapter 5 highlights other aspects than reliability that should be taken into consideration when selecting a x-mas tree configuration.

In Chapter 6 an evaluation of the reliability analysis is conducted.

Summary and recommendations for further work are in Chapter 7.

Acronyms are in Appendix A. Some definitions from the subsea production system are provided in Appendix B to help the reader understand the terminology.

Chapter 2

X-Mas Tree Function, Components, and Configurations

Understanding the functions of a XT is an important start for a reliability assessment. This chapter introduces the functions of a XT, what is used to achieve these functions, and the different configurations available. A literature study is conducted to achieve this goal.

The name XT originates from XTs on platforms or onshore. The valves were stacked on top of each other and were painted green. This resembled a Christmas tree and thus was named after its appearance. For subsea application the XT has many of the same functions, but are more complex and painted yellow.

2.1 Functions of a X-Mas Tree

Bai and Bai (2012) state that the typical functional requirements of a subsea XT are:

1. Direct the produced fluids from the well to the flowline (called production tree) or to canalize the injection of water or gas into the formation (called injection tree).

2. Regulate the fluid flow through a choke (not always required).

3. Monitor well parameters at the level of the tree, such as well pressure, annulus pressure, temperature, sand detection, etc.

4. Safely stop the flow of fluid produced or injected by means of valves actuated by a control system.

5. Inject into the well or the flowline protection fluids, such as inhibitors for corrosion or hydrate prevention.

NORSOK D-010 (2013) state similar functions but has one more function that is important:

6. Provide vertical tool access through the swab valve(s) for vertical trees or through crown plug(s) for horizontal trees.

NORSOK D-010 also has another function embedded in point number three. Not only should the annulus pressure be monitored, but also pressure adjustment of the annulus should be provided if necessary.

Point number five is not always implemented because it depends on the properties of the produced gas or oil.

2.1.1 Functional Analysis

Structured analysis and design techniques are used to model function blocks. Several blocks can be linked together and form a functional block diagram (Rausand and Høyland, 2004). This is a useful tool for breaking down the functions and understanding a system.

Integration Definition 0 (IDEF0) is based on and further developed from the structured analysis and design technique. *"For existing systems, IDEF0 can be used to analyze the functions that the system performs and to record the means by which these are done"* ISO 31320-1 (2012).

Functions are represented by boxes and with several arrows pointing in and out. There are four categories that each is represented on one of the four sides of the box, see Figure 2.1. Each box has a box name that in the example is X. The four categories are (ISO 31320-1):

Control a condition or set of conditions required for a function to produce correct output.

Output that which is produced by a function

Mechanism the means used by a function to transform input into output.

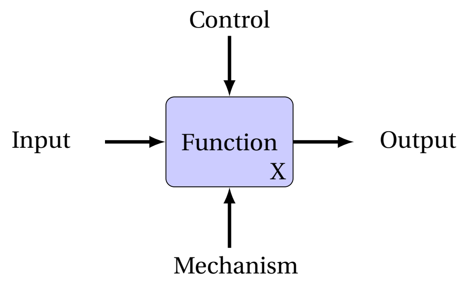


Figure 2.1: IDEF0 functional block (derived from ISO 31320-1)

Input that which is transformed by a function into output.

Three IDEF0 functional block diagrams have been made for the functions of a XT, see Figures 2.2, 2.3, and 2.4. The box name is equivalent to the function number from the previous mentioned functional requirements.

Function five is not represented in a figure because of this an optional function depending on the conditions of the flow from the well.

It is important to note that an IDEF0 diagram illustrates the function flow, not the actual flow. In Figure 2.2 the flow from the well comes into the XT and passes through the PMV and then the PWV, see Figures 2.6 and 2.7. The choke valve is located right after the PWV and then the flow goes into a connector with the jumper that goes towards the manifold. The two functions to stop and regulate flow are put in parallel because of their independent functions. The function to direct the flow through the valves is, however, necessary to fulfill the other two.

Each function described has one or more functional requirements. Figure 2.2 has a function to stop flow on demand. A functional requirement could be how fast this is done and the leakage rate after closure. Other function requirements can be how much pressure the valve can contain. How well the XT fulfills these function requirements affects the performance of the function and thus the reliability.

The IDEF0 diagrams are a good foundation for a structured view on the functions, this can be used as boundaries when a XT is analyzed.

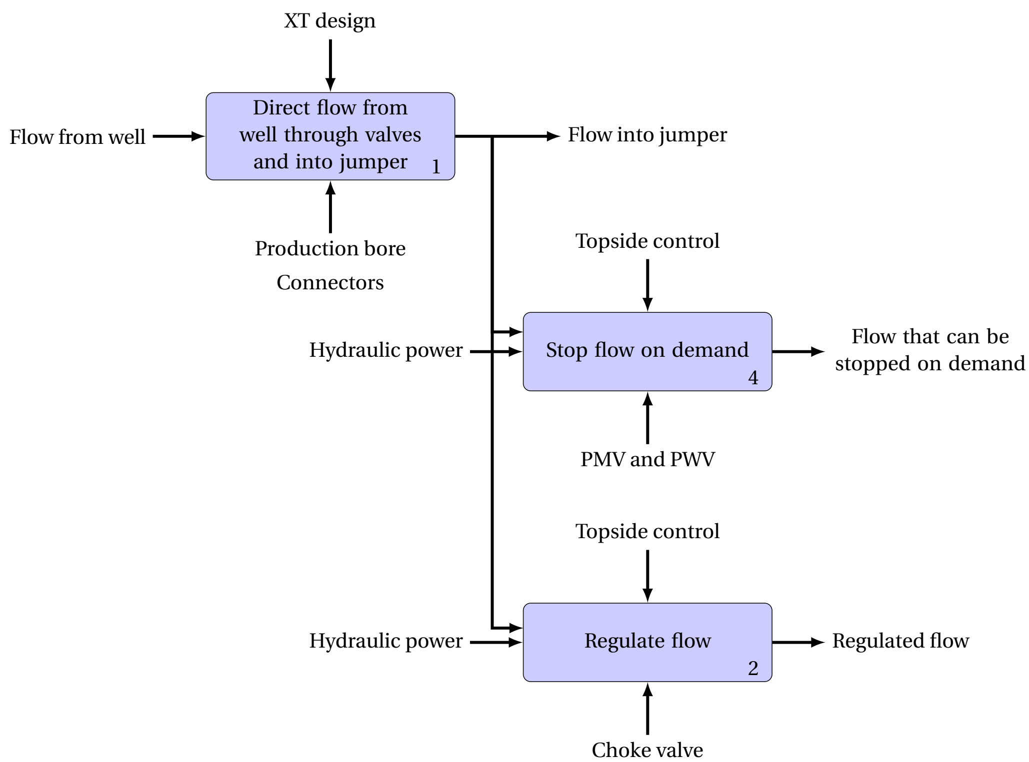


Figure 2.2: IDEF0 functional block diagram of XT functions 1, 2, and 4, see Section 2.1.

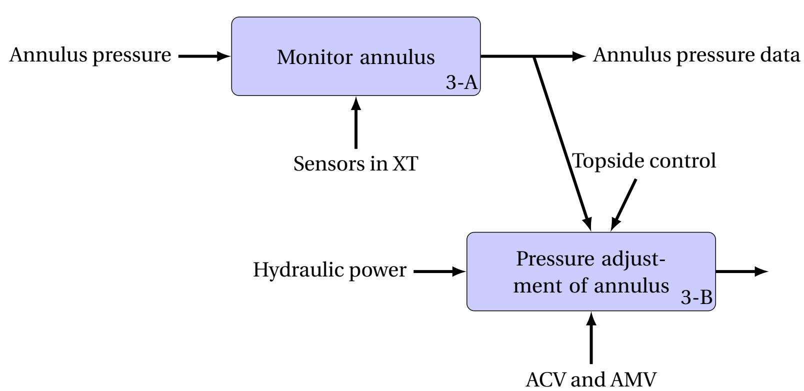


Figure 2.3: IDEF0 functional block diagram of XT function 3, see Section 2.1.

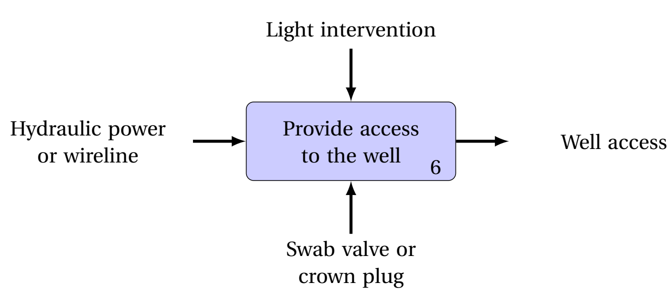


Figure 2.4: IDEF0 functional block of XT function 6, see Section 2.1.

Table 2.1: Main XT component reliability from the SubseaMaster database (taken from Molnes and Strand, 2007)

Item:	**Service time (item years):**	**No. of failures:**	**MTTF (years):**
Choke valve	224,2	18	14,9
Connector (Control/ flow line)	492,4	0	>492,3
Connector (Tree cap)	98,4	0	>98,4
Connector (XT)	552,0	0	>552,0
Piping	5546,3	6	924,4
Pressure compensation system	199,1	1	199,1
Sensor/ indicator	1018,2	7	169,7
Subsea control module	228,0	9	45,6
Valve w/actuator	5396,5	33	168,6
Wellhead	543,1	1	>543,1
XT plug	451,5	2	225,8

2.2 Main Components of a X-Mas Tree

The main components of a XT are described in the following sections. The reliability of a component can partially be described with Mean Time To Failure (MTTF), see Section 3.1 for more information on reliability measures. Table 2.1 shows the main components of a XT and their MTTF. The number of failures includes both installation (within 6 days) and in-service failures. The MTTF is calculated from only the in-service failures. This is why there is a disparity between the service time, number of failures, and the calculated MTTF.

2.2.1 Production Valves

Regulating and stopping flow from a well are accomplished by several valves that make up the XT. Two examples of how the valves are placed are shown in Figures 2.6 and 2.7.

The most important valve is the Production Master Valve (PMV). This is a part of the secondary well barrier and essential for the well's integrity. The PMV is the main valve responsible for stopping the flow from the well on demand in Figure 2.2, function 4.

The Production Wing Valve (PWV) is placed after the PMV and serves as a redundancy of the PMV. When the tree valves are required to stop the flow, the PWV is often closed first to allow the PMV to be closed without flow to reduce wear. The PWV also allow isolation from the flowline during vertical entry into a XT (Golan and Sangesland, 1993).

In Bai and Bai (2012) the PWV is named PMV2, this may cause some confusion therefore PMV and PWV are used in this thesis.

As seen in Table 2.1 the MTTF of the valves on a XT is 168,6 years. This is one of the more accurate MTTFs because of the large amount of service time recorded.

2.2.2 Choke Valve

The choke valve regulates the flow from the well; it is responsible for function 2 in Figure 2.2. It is normally placed on the XT after the PWV, but can also be placed on a manifold. In this report the choke valve is treated as a part of the XT.

The choke valve is exposed to wear due to erosion, and may require more frequent maintenance or replacement than the rest of the XT. The choke valve has the lowest MTTF of the components listed in Table 2.1. This is why the choke valve should be easy to retrieve (Golan and Sangesland, 1993). This is achieved by having a choke insert that allow for easy retrieval of the worn parts of the valve. This allows the choke valve to be replaced without pulling the XT.

A producing well may be required to be changed to an injection well (or vice versa) during the lifetime of an oil field. This can be achieved through some initial design adaptations on the XT and later changing the choke valve.

2.2.3 Other Valves

The annulus master valve and annulus workover valve *"are used to equalize the pressure between the upper space and lower space of the tubing hanger during normal production"* (Bai and Bai, 2012).

An annulus crossover valve is optional. It allows communication between the annulus and production bores. This *"can be used to allow fluid passage for well kill operations or to overcome obstructions caused by hydrate formation"* (Bai and Bai, 2012).

The swab valve on the vertical x-mas tree and the crown plug on the horizontal x-mas tree allow intervention into the well with wireline or coiled tubing.

2.2.4 Subsea Control Module

The Subsea Control Module (SCM) is an important part of the overall reliability of XT. It provides actuation and monitoring of most of the XT's functions. *"The typical SCM receives electrical power, communication signals, and hydraulic power supplies from surface control equipment"* (Bai and Bai, 2012).

The reliability is one of the lowest of the XT components (see Table 2.1). The control module has several redundant systems incorporated into it. Despite of this the complex electronic equipment make the SCM unreliable. The low reliability of the SCM is countered with the module being an independently retrievable unit.

Jardine (1986) states that modularization of equipment *"is a well known mean of improving system maintenance"*. Modularization offers the following benefits (Jardine, 1986):

- Reduction in the actual repair time of failed equipment via quick release modular connections and better access.
- Reduction in the number of different subsea tasks to be carried out.
- Reduction in the number of different types of spares required for system upkeep.

The module also simplifies the design phase because the module is the same on any XT, no matter the configuration or size. The content of the SCM will be different, but the connector, guiding, and size will be the same.

2.2.5 Connectors

The connection between the XT and the wellhead is typically done with a hydraulic connector. This is a modified BOP connector that has been specialized for subsea application (Bai and Bai, 2012). Table 2.1 shows that the reliability of the connectors is not recorded as a problem. The critical phase of the connector is during connection. Failures will be discovered quickly due to function and pressure testing before the well is put into service.

2.2.6 Sensors

To fulfill function 3-A (see Figure 2.3) the XT need various sensors. Bai and Bai (2012) state that the sensors used in a XT are pressure and temperature sensors, placed in the annulus and production bore and upstream and downstream of the choke.

Golan and Sangesland (1993) state that the sensors generally in a tree are pressure, temperature, sand erosion, valve position, and hydrocarbon leak detection sensors.

Some customers also require that the flow from the well is monitored with a flow meter. Either a wet gas flow meter or multiphase flow meter depending on the type of well.

The different sensors available for a XT relate to different types of well, fields and oil companies with different specifications. What kind of sensors installed on a XT is therefore tailored every time.

Some sensors may be required to be changed during the lifetime of the well. Sensors may be worn out or the conditions of the well may change so much that a well parameter goes beyond the range of the sensor. As seen in Table 2.1, the MTTF of sensors and indicators a relatively high. The changing parameters of a well may be a more frequent reason of sensor replacement than failures.

As mentioned in Section 2.2.2, a production well may be changed to an injection well. This will also require changing some sensors. This can be solved with placing some sensors and the choke valve into a retrievable Flow Control Module (FCM). The term FCM is used by GE Oil & Gas and in this thesis, OneSubsea use the term retrievable process module. A retrievable FCM has some other benefits as well, such as lower weight of the XT that can be beneficial for rig cost during installation. However, the main reason for a FCM is improving system maintenance as previous stated in Section 2.2.4.

For the Åsgard field the minimum lifetime is 20 or 30 years, here the choke valve and multiphase flow meter are put into a FCM. The FCM can be replaced with a monohull vessel in less than 48 hours (Østebø et al., 2001) which can save a lot of time in rig cost and mobilization time.

2.3 The Main X-Mas Tree Configurations

The oil companies have different technical requirements that result in adaptations on the XT to the specific buyer. Also the oil fields require different functions on the XT. This has resulted in a wide array of XTs installed around the world.

There are two main configurations of XTs. The conventional XT that is called a dual bore tree or a Vertical X-mas Tree (VXT). The other main configuration is called a Horizontal X-mas Tree (HXT).

GE Oil & Gas has developed a tree configuration they call the Deepwater Vertical X-mas Tree (DVXT). The DVXT is not a conventional VXT; it is installed with a Tubing Head Spool (THS) that incorporates some benefits from the HXT into the VXT. In this thesis the DVXT is treated as an independent type of XT configuration in addition to the HXT and the VXT. Other XT suppliers have similar configurations; OneSubsea call theirs a vertical monobore subsea tree.

2.3.1 Vertical X-Mas Tree

A VXT configuration is shown in Figure 2.6. The VXT is also called a conventional XT or a dual bore XT. The main characteristic of the VXT is that the production and annulus bores run vertically in the tree with the main valves oriented vertically in the main block of the tree (Bai and Bai, 2012).

The well is completed and the tubing hanger hung in the wellhead before the VXT is installed. Well completion is when the production tubing suspended in the tubing hanger is landed in the wellhead or XT.

The VXT lands on top of the wellhead and tubing hanger. The orientation of the VXT is important because of the asymmetric dual bore and the control lines for downhole equipment on the tubing hanger (Bai and Bai, 2012).

A VXT is installed with an installation/workover dual-bore riser and a tree running tool. On a live well a lower marine riser package is required, this functions the same way as a Blowout Preventer (BOP) and is installed between the tree and the installation/workover riser (Richbourg and Winter, 1998).

Bai and Bai (2012) state that a VXT is larger and heavier than a HXT. However, OneSubsea

(2015) state that the VXT and HXT *"typically have the same size, weight, and footprint when comparing equivalent systems"*. The conflicting statements may suggest that there may be a difference, but it is negligible when choosing between the configurations. The main driver of the weight of the XT is not the configuration but the bore size and pressure rating.

2.3.2 Horizontal X-Mas Tree

A HXT configuration is shown in Figure 2.7. The valves on a HXT are located horizontally to the sides.

The HXT is installed on top of the wellhead before the well is completed. The well is then completed through the HXT and the tubing hanger is hung into the HXT. This allows the tubing to be pulled without the need to pull the tree.

The tubing hanger is installed with casing tubular joint through a regular drilling BOP connected to the HXT. However, this requires a complex landing string with valves that is special made to the particular BOP used. This is because of the shear rams incapability of cutting certain parts of the landing string (Bai and Bai, 2012).

2.3.3 Deepwater Vertical X-Mas Tree

The DVXT differs from the VXT because of a THS that is installed on top of the wellhead before the well is completed.

The THS is a combination of a tubing head and a completion guidebase.

ISO 13628-4 state that the uses of a tubing head are:

1. Provide a crossover between wellheads and subsea trees made by different equipment manufacturers.
2. Provide a crossover between different sizes and/or pressure ratings of subsea wellheads and trees.
3. Provide a surface for landing and sealing a tubing hanger if the wellhead is damaged or is not designed to receive the hanger.
4. Provide means for attaching any guidance equipment to the subsea wellhead.

Only number 4 use is valid for the THS but the others may also apply in certain cases.

ISO 13628-4 also state that the tubing hanger may be landed in the tubing head which is the case on the DVXT configuration. Similar to a HXT the THS provides passive orientation of the tubing hanger. The DVXT has a monobore tubing hanger. A bore in the THS with an annulus isolation valve, bypasses the tubing hanger as seen in Figure 2.5, valve 16.

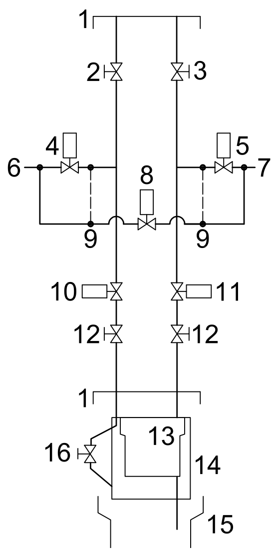
"A completion guidebase, may incorporate piping, flowline connections, and tree piping interface hardware" (Richbourg and Winter, 1998). For the DVXT this means that the flowline connection is not on the XT as usual. The THS supports a piping spool that connects to the DVXT and to the jumper. This allows the jumper to be connected before the DVXT is installed and remain connected if the DVXT is pulled.

The DVXT has a concentric dual-bore design; this means that a dual bore riser is not necessary as with a VXT. A regular subsea BOP can be used together with a marine riser and a tubing hanger running tool during intervention and installation.

The THS provides guidance with orientation fins that orients the DVXT when it is landing onto the THS (GE Oil & Gas, 2012).

After the THS is installed onto the wellhead, the well is completed. The DVXT is then installed on top of the THS as a normal VXT. The connection to the THS consists of two connectors, one with a regular wellhead connector that connects to the THS and tubing hanger. The other is a smaller but similar connector as the wellhead connector, this connects to the flowline connector spool on the THS.

The DVXT configuration is heavier than the VXT and HXT, but the weight is distributed between the two lifts of the THS and the tree. This can be beneficial if the XT weight is around the crane capacity of the installation vessel. Because of the two main components, the DVXT takes up more deck space on the installation vessel.



Key

1 CAP
2 ASV (manual or failed closed or optional plug)
3 PSV (manual or failed closed or optional plug)
4 AWV
5 PWV
6 annulus
7 production
8 XOV
9 option
10 AMV
11 PMV
12 optional master (manual or hyd.)
13 tubing hanger
14 tubing head
15 wellhead
16 annulus isolation

Figure 2.5: Example of a vertical tree on a tubing head (taken from ISO 13628-4).

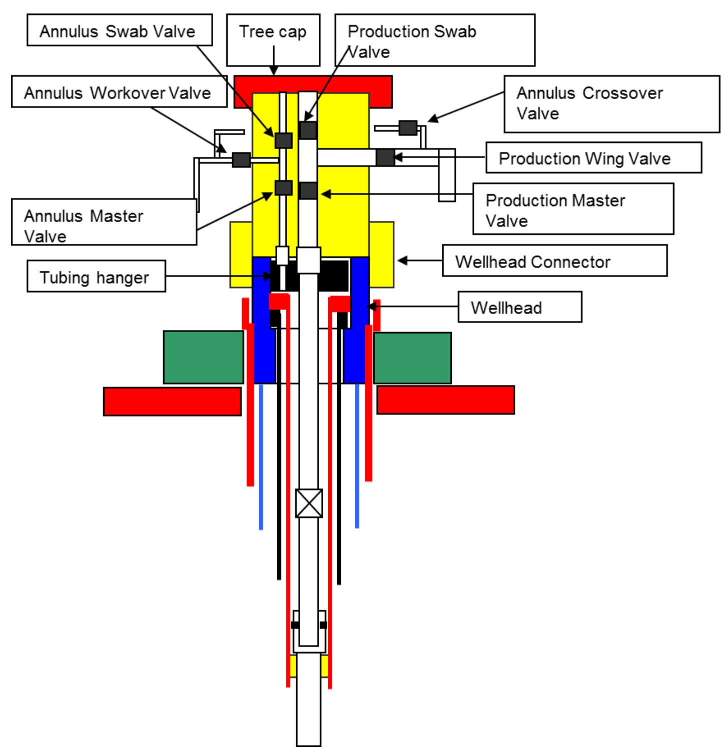


Figure 2.6: Subsea well with VXT, dual bore through XT and TH (taken from Norwegian Oil & Gas, 2012).

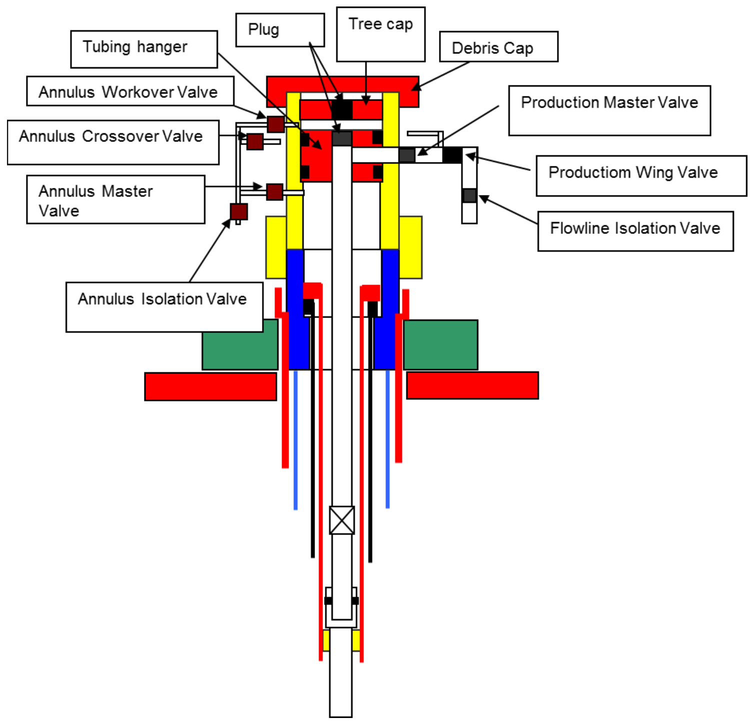


Figure 2.7: Subsea well with HXT (taken from Norwegian Oil & Gas, 2012).

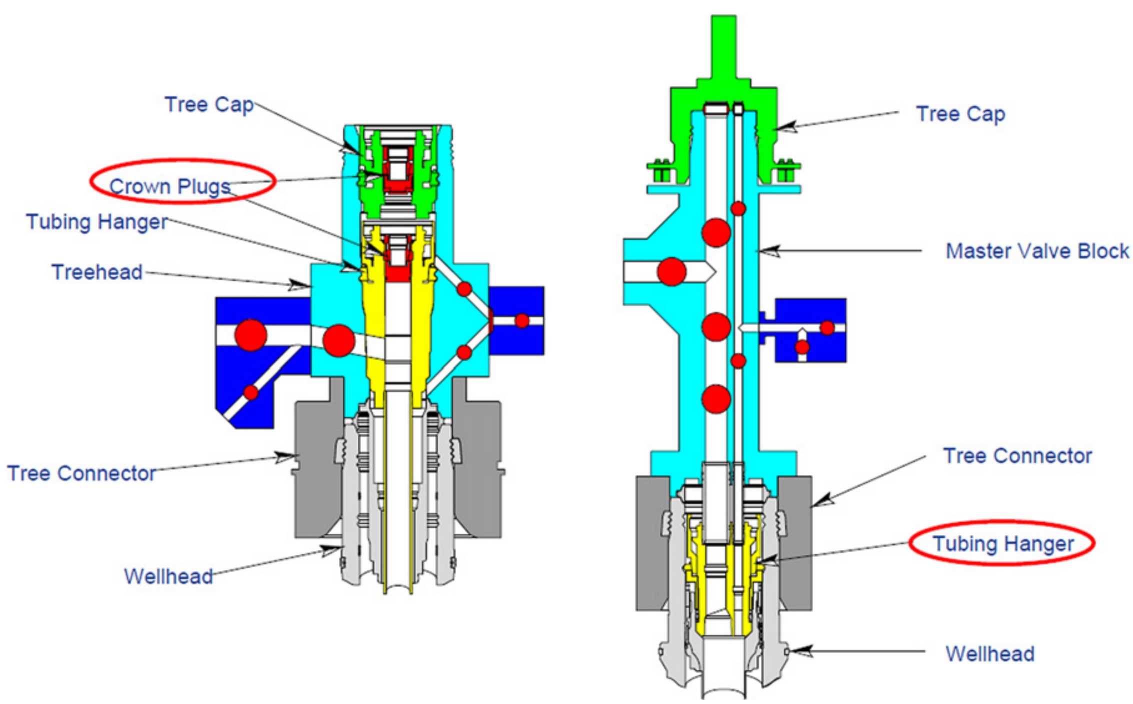


Figure 2.8: XT block assembly, HXT to the left and VXT to the right (taken from Bai and Bai, 2012)

Chapter 3

Approaches to Reliability Assessment

Reliability can defined as the *"ability to perform as required, without failure, for a given time interval, under given conditions"* (IEV Online, 2015).

A reliability assessment does not have a good definition compared to the definition of a risk assessment. Risk assessment is defined as the *"overall process comprising a risk analysis and a risk evaluation"* (IEV Online). This can be transferred to the description of a reliability assessment in that an assessment consists of an analysis and an evaluation.

3.1 Measures of Reliability

Rausand and Høyland (2004) use four measures of reliability of non-repairable item. The reliability function, failure rate function z(t), Mean Time To Failure (MTTF), and mean residual life.

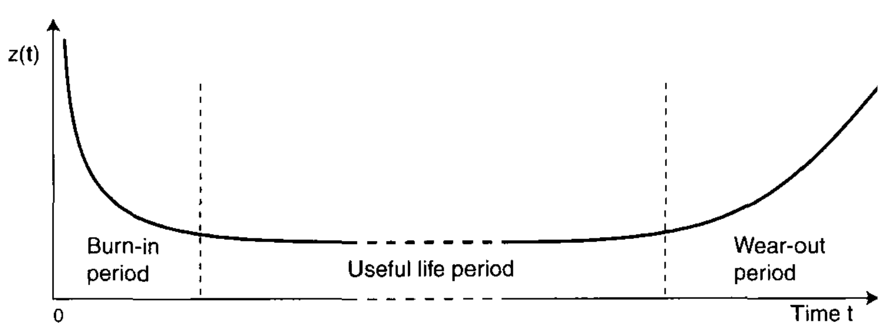


Figure 3.1: The bathtub curve (taken from Rausand and Høyland, 2004).

The failure rate function and MTTF are the most used in subsea reliability engineering.

The exponential distribution is the most common probability distribution that is used to model the lifetime of a non-repairable item. The exponential distribution has a constant failure rate. Rausand and Høyland (2004) state that this distribution *"may be a realistic life distribution for an item during its useful life period"*. The useful life period is the flat middle part of the bathtub curve in Figure 3.1. This is a good assumption since most components will only be in this part during the lifetime of the system. In addition *"most of the commercially available reliability data sources are based on the assumption of constant failure rates"* Rausand and Høyland (2004).

Molnes and Strand (2007) state that SubseaMaster does not include failures within the first six days after installation into the MTTF calculations. Brandt and Eriksen (2001) refers to this as the *"infant mortality"* and are subsea components that sometimes fail shortly after installation or an intervention. In Figure 3.1 the infant mortality is the same as the burn-in period. By removing the infant mortality from the calculation of failure rate, the result is more accurate. To cover the infant mortality in a reliability model, Brandt and Eriksen (2001) state that *"an installation failure probability can be applied"*.

With the exponential distribution the relationship between the failure rate (λ) and MTTF is constant, as seen in Equation 3.1, taken from Rausand and Høyland (2004). MTTF is often used when presenting reliability data because it is a more relatable number than the failure rate. However, when using MTTF it is important to note that *"MTTF is merely a performance indicator, not a lifetime prediction figure"* (Molnes and Sundet, 1993).

$$MTTF = \frac{1}{\lambda} \tag{3.1}$$

3.2 Reliability System Analysis

Rausand and Høyland (2004) state that *"the main reliability measure for a maintained item is the availability"*. Availability is defined as the *"ability to be in a state to perform as required"* (IEV Online). A more comprehensive definition is that *"availability depends upon the combined characteristics of the reliability, recoverability, maintainability, and the maintenance support performance"* (IEV Online). Rausand and Høyland (2004) mentions that the reliability incorporated under availability is the inherent reliability.

Recoverability and maintenance support performance are the same for the XT configurations and are therefore not further discussed.

Maintainability is defined as the *"ability to be retained in, or restored to a state to perform as required, under given conditions of use and maintenance"* (IEV Online).

From these definitions it can be derived that the system reliability is the overall systems ability to function and the inherent reliability is the ability of an items to function without failure.

A subsea XT is designed to last as long as possible without maintenance. Depending on the type of XT, the maintainability of the tubing would change. This would affect the availability of the well. So even when a XT is not considered a maintained system, availability is a key factor in the system reliability of the well.

3.2.1 RAM Analysis

Calculating the availability of a system such as a subsea production well is very complex. Many oil companies use Monte Carlo next event simulation data software to simulate the availability, this is called a Reliability, Availability, and Maintainability (RAM) analysis. Miriam RAM Studio and Maros are commonly used software for this kind of RAM analyses.

Well intervention and subsea repair costs can be quantified through a RAM analysis. Combined with CAPEX and OPEX (see Section 5.2) this can be used as support in selecting subsea solutions with the lowest life cycle cost (Brandt and Eriksen, 2001).

The system is modeled with flow diagrams and reliability block diagrams. Then the software generates random events with a specific probability distribution. Scheduled and conditional events are also included. This simulates a lifetime scenario, when this is done enough times the average will show an estimate of the actual lifetime. In Aven and Pedersen (2014) 20 000 simulations were run to give negligible statistical estimation errors. Brandt and Eriksen (2001) state that the output *"will always be uncertain, and rely solidly on the quality of the reliability data."* As well Aven and Pedersen (2014) state that *"production assurance analyses are based on the project team's knowledge at the time of the analysis. This knowledge is to a large extent reflected in the assumptions made during the analysis."* Knowledge on the system and quality data used right is essential in achieving an applicable result.

Aven and Pedersen (2014) address model uncertainties in a RAM analysis. In the article a RAM analysis is conducted on a subsea production system as an example. It is suggested that an importance score in two dimensions are contributed to each assumption made for an analysis. The two dimensions are:

Sensitivity the effect changing the assumption has on the predicted production availability.

Uncertainty the level of uncertainty related to deviations for the assumptions made.

Aven and Pedersen (2014) use the importance score system on the assumptions for a subsea production system RAM analysis. An assumption of three months mobilization time stands out with both high sensitivity and uncertainty. Especially for subsea productions systems mobilization time is very important for the availability in analyses. This enforces the focus on the inherent reliability of the subsea components.

Drakeley et al. (2001) is an article where RAM analysis for the new technology of an intelligent well is discussed. A methodology for establishing appropriate input data was presented. In an analysis of new technology establishing appropriate input data is difficult. For new concepts such as the DVXT this may be a problem. Most of it utilizes proven technology but the system still requires data to be adapted. An important part of the method in Drakeley et al. (2001) is uncertainty management. Several actions were taken to minimize the effect of data and modeling uncertainties. The actions were; sensitivity analysis, uncertainty distributions such as standard deviation, highly sensitive and uncertain components were closely followed up, thorough review of models and input data, and application of expert judgments to calibrate data. The analysis in Drakeley et al. (2001) suffered from the limited field experience of the new technology; however, they still concluded that the analysis contributed to better design increasing the reliability. This is important with regards to the DVXT, with good control of the uncertainties a RAM analysis can still provide an adequate decision basis for choosing a XT configuration.

Lee et al. (2004) has conducted a RAM analysis on the subsea production system. In this analysis the main equipment reducing system availability were found to be the SCM and the wellhead connector. The SCM is expected to be a low reliability component and is therefore easy to retrieve. The reason for the low reliability on the wellhead connector is not stated in the article. This analysis concluded that the some configuration of the facilities needed to be changed and inspection intervals for maintenance were set to reach the availability goal of 99.0 %. The goal was reached by adapting a 2 out of 3 system of the subsea wells to facilitate the further system.

The finding of Lee et al. (2004) of the wellhead connector as one of the equipment reducing system reliability is somewhat surprising. Jardine (1986) state the wellhead connector to be *"highly reliable"*. In Table 3.1 the MTTF of the connector and wellhead is very high. The reason for the unavailability caused by the wellhead connector may be explained by Jardine (1986) which state that *"it is necessary to look beyond the equipment's unreliability and consider its failure impact, its method and time to repair, i.e. the equipment's overall importance within its proposed system environment."* If the wellhead connector is damaged the well may be permanently shut down or extensive repairs have to be conducted. This shows the importance of conducting a RAM analysis, the inherent reliability is not enough to indicate the system reliability.

3.3 Reliability Data

Reliability data are required to accurately model and analyze a system. Molnes and Sundet (1993) state that *"the value of reliability data is time limited. It is therefore vital that operating companies have the capabilities required both in terms of manpower and software to collect data on a continuous basis"*. This data can be used to improve the reliability of the equipment installed and to later design reliable equipment.

For the Åsgard field, reliability data were used to choose a special durable choke valve to meet the expected hard use on the field. The chosen choke valve appears to meet the requirements of the field proving that using reliability information adds value to a project (Østebø et al., 2001).

3.3.1 Reliability Data Sources

Good reliability data is essential for a reliability analysis to be useful. There are several sources of data in different industry sectors. For subsea developments Brandt and Eriksen (2001) state that component reliability can be obtained from the following sources: general industry data banks, vendor data, expert judgments, or synthesized data. In subsea oil and gas there are two

Table 3.1: Main XT component reliability, derived from OREDA (2009) and SubseaMaster (Molnes and Strand, 2007)

Item:	**SubseaMaster MTTF (years):**	**OREDA MTTF (years) All failures:**	**OREDA MTTF (years) Critical failures:**
Choke valve	14,9	6,7	107,4
Connector (XT)	>552,0	308,5	713,5
Sensor/ indicator	169,7	12,7	178,4
Subsea control module	45,6	5,4	21,5
Valve w/actuator	168,6	207,6	207,6
Wellhead	>543,1	326,2	439,1

main relevant industry data banks: the Offshore Reliability Database (OREDA) and WellMaster/SubseaMaster.

"OREDA is a project organization sponsored by oil and gas companies with world-wide operations. OREDA's main purpose is to collect and exchange reliability data among the participating companies" (OREDA, 2009).

OREDA reliability data from a participating company is fully available to that one company. Data from other companies are restricted. The OREDA handbooks are released publicly and contain a lot of data on specific components. This data in the handbooks are rather old, the 2009 handbook contains data from years from 2000 to 2003. The data in Molnes and Strand (2007) are collected from 2004 to 2007 and are therefore more up-to-date.

In OREDA (2009) there is reliability data on subsea XTs. OREDA has collected data from 208 VXTs and 62 HXTs. This is more than Molnes and Strand (2007), which contains reliability data from 104 subsea wells.

SubseaMaster does not distinguish between critical, degraded, and incipient failures which OREDA does. The data from OREDA is originally presented as failure rate per 10^6 hours. OREDA also presents mean, lower, upper and standard deviation of the data to allow the reader to know the uncertainty of the data. This is not included in the Molnes and Strand (2007) report, but may be included in the SubseaMaster restricted database.

In Table 3.1 XT components reliability data from OREDA (2009) and Molnes and Strand (2007) are compared. The components which were similarly described were included. The failure rate from OREDA has been calculated to MTTF. From the comparison much of the data coincides. The largest differences are the sensor/ indicator and the SCM. Technology have made great advances in the last decade, this could explain why the newer data show a considerably better reliability.

3.3.2 Bottom-up Versus Top-down Approach

Combining data from the OREDA database and conventional reliability block diagrams often result in a lower reliability than experienced in the field. GE Oil & Gas refers to this as a disparity between bottom-up approach and top-down approach. This is further researched in Stendebakken (2014).

Bottom-up approach refers to reliability models that use specific XT component reliability data in a reliability model for the whole XT system. The component data in the bottom-up approach is taken from GE's own database of components and data received from OREDA on GE's trees in service at the oil companies.

Top-down approach refers to high level reliability and availability experienced in the field. The high level data is from the actual number of times trees are retrieved for service due to failures.

The disparity may be related to how the failures are reported and classified in the reliability database. If a failure is not a critical failure, this may not be noticed and may not require the retrieval of the XT from the seabed. This requires the distinction between light intervention and heavy workover in the database.

At the end of the bathtub curve (Figure 3.1) the failure rate increases. If some components on the XT reach this part during the lifetime of the XT this may be a source of deviation in the bottom-up model. The choke valve described in Section 2.2.2 is a component that has a high wear. It may be assumed that the failure rate of the choke valve starts increasing during the lifetime of the XT. To describe this with another probability distribution such as the Weibull distribution can be more realistic; however, this is most likely not the main source of deviation in the bottom-up approach.

The disparity between the approaches may be a result of inadequate models, but the most likely cause is the reporting and classification of failures to the database. A possible cause of error is when a VXT is retrieved due to a failure in the tubing. The normal procedure is then to overhaul the VXT, failures may then be found and classified as critical. However, the XT would never have been retrieved because of this failure. Classification of failures and control of in what setting failures are discovered is critical for achieving good data and models.

GE modifies their data based on experience so that the top-down and bottom-up approaches correspond. On failures classified as critical, they sometimes use a Pareto rule that implies that 80% of the failures only lead to light intervention and 20% requires a heavy workover. This limits the retrieval rate in the analysis and closes the gap between bottom-up and top-down.

GE has by this method removed some of the uncertainties of their system model for RAM analysis. As previously stated from Drakeley et al. (2001) in Section 3.2.1; with good handling of the uncertainties a good analysis can still be obtained. Especially expert judgments to calibrate data can be used to close the gap between the bottom-up and top-down approach to achieve realistic models.

Chapter 4

Qualitative Reliability Analysis of X-Mas Tree Configurations

In this chapter a qualitative reliability analysis is conducted on the differences between the XT configurations.

This analysis is a qualitative analysis of the reliability of the XT configurations compared to each other. A literature survey has been conducted to identify reliability drivers that differentiate the reliability of the XT configurations.

The analysis is not for a specific type of well, thus XTs are discussed in a broad setting. It is not specific on water depth or if it is an oil or gas well. Only production wells are analyzed, not injection wells. It is not differentiated between satellite, cluster, or template wells.

4.1 What to Assess

When discussing the different XT configurations it is important to assess the required functions of a XT introduced in Section 2.1.

In Section 2.1.1 it is mentioned that the IDEF0 diagrams can be used as functional boundaries for an analysis. In an analysis comparing the reliability some functions are more important that other. The function to stop flow on demand is important for the reliability of the tree, but will not differentiate the reliability of the different types of XTs. This is because the valves are basically the same on the different XT configurations.

The functions of the different XT configurations are the same. Input, control and output should also be the same. That leaves mechanism and how the mechanism affects the function as the main differences. As previous stated the valves are the same on the different configurations. This leaves the production bore, connectors, and swab valve/crown plug to be analyzed.

An important function of the well is to be able to retrieve the production tubing. This is not a direct function of the VXT; however, it is for the HXT. Functions like this that are affected by the XT should also be considered in an analysis.

Redundancy is an important aspect of system reliability. However, the relevant systems differentiating the XT configurations do not have redundancy, thus it is not relevant. Jardine (1986) state that *"in deep water, the advantages of redundancy will diminish and the philosophy of simplicity in design will prevail"*. This analysis do not differentiate between deepwater and shallow water application of the XTs. Simplicity in design is still a philosophy worth keeping in mind during the analysis because of the positive impact it has on reliability.

This section aims to identify the reliability drivers that will differentiate the configurations in a system reliability analysis.

4.1.1 Maintainability

"Statistically, most workover interventions on subsea trees are due to downhole problems rather than problems with the tree" (Richbourg and Winter, 1998). On the other hand Molnes and Sundet (1993) state that gas/condensate producing wells has a *"history of relatively few failures and corresponding high tubing reliability"*. This is a big driver of the system reliability and one of the main factors when deciding the XT configuration of a well.

The downhole problems of an oil well can be contributed to different characteristics of the oil. Characteristics such as sand content, water cut, scale, and H_2S content are some factors that may affect the reliability of the tubing. The concentration of these characteristics compared to tubing failures are not assessed by Molnes and Sundet (1993).

Aven and Pedersen (2014) state that for a subsea production system *"the active repair times are short compared with the mobilization time, and can be ignored"*. This implies that the only important factor for a XT is the inherent reliability, if every failure requires the same type of vessel to be mobilized. As far as the author has understood there is no difference in the types of vessel required to perform maintenance on the different XT configurations. But it may cause a significant difference of the active repair when the XT has to be retrieved as well. Aven and Pedersen (2014) may not have included extra lifting operations into the statement, just the actual repair of a component.

How maintainable the XT and the well system are is an important contributor towards the system reliability. This is also a key difference between the XT configurations so maintainability should be a focus point of the reliability analysis.

4.1.2 Leak Paths

The function to direct flow is the first function of the XT function block diagram shown in Figure 2.2. Without this function the next functions will fail. The most important functional requirement to this function is to direct flow without leakage to the surroundings.

The main focus of well integrity (see Appendix B) is well barriers. The XT is a part of the secondary well barrier in a producing well (NORSOK D-010). This means that a failure in the XT alone will not lead to a blowout. A leakage may still lead to some fluids released to the environment. This would also lead to stop in production from the well for some time until the XT is replaced. This is because *"upon confirmation of loss of the primary or secondary well barrier, the well shall be shut-in and the remaining well barrier verified. Only activities related to the re-establishment of the well barrier shall be carried out on the effected well"* (NORSOK D-010).

ISO 13628-4 state that *"the number of potential leak paths should be minimized during system design"*. More leak paths may lead an unacceptable level of safety, a higher probability of leakage, and a lower system reliability.

The parts of a XT that has the potential of being a direct leak path to the surrounding are the connectors, wellhead, and XT block. The XT configurations have different number of connectors, forces on wellhead, and design of the bore. This should be looked into in a comparison.

4.1.3 Flow Control Module

As mentioned in Section 2.2.6 the choke valve and some sensors may be put into a retrievable FCM. This will improve the maintainability of those parts. However, this makes the system more complex and adds potential leak paths. This may impair the reliability and safety of the tree. The need for a FCM may be different for the different XT configurations and should be discussed in the analysis.

4.2 Vertical X-Mas Tree

In Table 4.1 the HXT has over twice the MTTF of the VXT. This may relate to that VXTs were more frequently used before and newer wells more frequently have HXTs. They also may have newer more reliable technology, the older VXTs may lower the MTTF and a new VXT may have a higher MTTF. It is difficult to discuss this further without improved knowledge on the data collected.

4.2.1 Maintainability

The VXT is easier to replace than a HXT because the tubing hanger is hung in the wellhead.

If the tubing is going to be replaced a VXT provides a more comprehensive procedure with more operations. Disconnecting the jumper and the umbilical has to be done first, then the tree can be removed and eventually the BOP can be put on the wellhead and the tubing hanger and tubing retrieved. This is the reason that a well that is expected to have downhole problems is equipped with a HXT and vice versa. *"A HXT is not recommended for use in a gas field because interventions are rarely needed"* (Bai and Bai, 2012). Retrieving the tubing from well with a HXT is a simpler and less time consuming procedure. What kind of maintenance that is expected in a well and XT is therefore key in the maintainability of the system. This favors one configuration over the other in a maintainability perspective depending on the well.

Table 4.1: XT configuration reliability (derived from OREDA, 2009)

Item:	**No of units:**	**MTTF (years) All failures:**	**MTTF (years) Critical failures:**	**Active repair time (hours), all failures:**	**Active repair time (hours), critical failures:**
VXT	208	8,5	46,0	26,6	25,0
HXT	62	22,9	116,5	140,0	240,0
VXT Wellhead	199	292,7	407,7	288,0	288,0
HXT Wellhead	62	193,5	207,6	-	-

In shallow waters the time used to retrieve a XT is much shorter than in deep water. When retrieving the tubing from shallow water the extra time used to pull a VXT may be negligible.

The swab valve of the VXT allows shorter time spent with wireline operations. It is faster to open the swab valve than to retrieve the crown plug of a HXT in the preparation of a wireline operation; however, this time is very short and negligible.

4.2.2 Leak Paths

The VXT has a swab valve compared to the HXT which has a crown plug. As seen in Table 2.1 a valve (MTTF of 168,6 years) has a lower MTTF than a XT plug (MTTF of 225,8 years). The XT plug is assumed to be the crown plug of a HXT.

The two plug failures were both failure to disconnect. The valve failures vary more but the main contributors were spurious operation and failure to close (Molnes and Strand, 2007).

A valve instead of a plug is therefore a slightly worse option with regards to reliability and leak paths due to the nature of the failures.

4.2.3 Flow Control Module

Since it easier to retrieve a VXT it may be available for repair on a rig or sent to the manufacturer for an overhaul, temporarily replaced by a backup XT. Replacing or repairing the choke valve or a sensor on this occasion may remove the need for pulling the tree because of the choke valve or the need for replacing this subsea.

A VXT without a FCM would not have the negative effect of the FCM on safety and still have good maintainability of the choke valve and sensors.

4.3 Horizontal X-Mas Tree

4.3.1 Maintainability

As mentioned in Section 4.2.1 a key difference between a VXT and a HXT is how easy it is to retrieve the tubing. Bai and Bai (2012) state that *"an HXT is applied in complex reservoirs or* *those needing frequent workovers that require tubing retrieval, whereas a VXT is often chosen for simple reservoirs or when the frequency of tubing retrieval workover is low"*.

Table 4.1 show a considerably worse repair time for the HXT. This relates to the extra time spent retrieving the tubing before retrieving the HXT.

4.3.2 Leak Paths

All of the XT configurations use a BOP during retrieval of the tubing. The HXT has the BOP mounted on top of it compared to the VXT where the tree is retrieved first and the BOP is connected to the wellhead. When the BOP is on top of the HXT it adds height to the already high BOP stack. This increases the moment force on the wellhead. *"Bending loads at the flex joint are a function of the riser bottom tension and the riser bottom angle. These loads can result in large bending moments at the wellhead due to the moment arm arising from the BOP stack height."* (Golan and Sangesland, 1993). With the increased height from the HXT the strength of the wellhead and connector may be a problem.

As previously discussed in Section 3.2.1, Lee et al. (2004) found the wellhead as a component reducing availability. The wellhead is critical for the wells integrity and replacing a damaged wellhead is not possible requiring a new costly well to be drilled. This is shown in the extensive repair time of the wellhead in Table 4.1.

According to Holand (1997) tripping out is one of the top three most dangerous activities for a well, retrieval of the tubing is therefore a dangerous activity. This raises the question of which XT configuration has the safest setup during retrieval of the tubing. The HXT setup with the BOP on top of the HXT makes this solution more vulnerable.

As seen in Table 4.1 the HXT wellhead has a considerably lower MTTF than the VXT. The low MTTF of the HXT wellhead may be related to the low number of units recorded. No failures were recorded as well, how the failure rate then was calculated is uncertain. If the MTTFs are assumed to be correct, the level of availability and safety may be considerably lower than of the VXT.

4.3.3 Flow Control Module

On a HXT the cost of pulling the tree is high, this imply that a FCM is the best choice with regards to maintainability. However, this may impair the safety of the HXT with the addition of complexity and leak paths.

4.4 Deepwater Vertical X-Mas Tree

4.4.1 Maintainability

The DVXT is more maintainable than the VXT. Because of the piping spool on the THS the jumper is not disconnected when retrieving the tree. The annulus isolation valve also is beneficial as a secondary barrier of the annulus during XT retrieval because it eliminates the need for a temporary barrier in the annulus. The DVXT is therefore more maintainable for both tree and tubing problems than the VXT. However, the HXT still has an advantage when over the DVXT on tubing retrieval.

4.4.2 Leak Paths

The DVXT is a more complicated XT than the other configurations. Extra connections are made subsea; the THS to wellhead and the XT to the flow spool on the THS. Connections are a vulnerable part with regards to leak paths. As seen in Table 2.1 the connectors are a very reliable component; however, the infant mortality is not assessed.

If the connector fails during installation it has a high chance of being discovered. If a connector is damaged this would require the connector to be replaced or the whole tree replaced. This would cost a lot of money and installation time. The infant mortality in the burn-in period is not found to be a problem but may be so. Many connector that is supposed to connect at the same time make installation difficult and more tedious since more time is spent overseeing and testing. When the connection is made and the XT put in service the low failure rate means that in service the extra number of connectors are not a problem for the availability.

4.4.3 Flow Control Module

The cost of pulling a DVXT is the lowest of the three configurations, this may eliminate need for a FCM from a maintainability perspective.

Chapter 5

Qualitative Comparison of X-Mas Tree Configurations

This chapter highlights other factors than reliability that are important during the selection of XT configuration.

5.1 OneSubsea Tree Selector Tool

To help their customers, the XT provider OneSubsea has made a tree selector tool available on their web page (OneSubsea, 2015). The OneSubsea Tree Selector Tool (TST) is fully available to their customers, but only a simple version that is available to the public is used in this thesis.

The TST uses ten categories listed in Table 5.1. In each category a slider is placed to rank the importance of that category to the customer. The importance is rated from none to critical. The result is given in a percentage on how each tree suits the customer's ranking of the importance of the categories.

With every category rated to middle criticality a baseline is established. Changing one category at a time gave an indication on how each category affected what the result, this is shown in Table 5.1.

OneSubsea has three types of XTs that are ranked in the result. A VXT, a HXT and a vertical monobore subsea tree that looks similar to GE's DVXT. In the description of OneSubsea's tree they mention a tubing spool that lets the annulus bypass the monobore tubing hanger. The

Table 5.1: OneSubsea tree selector tool, favored type of XT if category is critical = X (derived from OneSubsea, 2015)

No:	Category:	VXT:	DVXT:	HXT:
1	CAPEX costs	-	-	X
2	OPEX costs	X	X	-
3	Availability of installation tooling	-	-	X
4	Tree size and weight	-	-	X
5	Safety barriers in installation	-	-	X
6	Safety barriers in intervention	-	-	X
7	Light-well intervention flexibility	X	X	-
8	Downhole communication fault during installation	-	X	-
9	Ease of access to tubing	X	X	-
10	Ease of access to tree	-	-	X

author has used this information to state that OneSubsea's vertical monobore subsea tree and the DVXT from GE are similar and can be treated as the same.

5.2 Cost

Cost is another factor that influences the choice of XT configuration. Costs are divided into two categories:

Capital Expenditure (CAPEX) is the total amount of investment necessary to put a project into operation and includes the cost of initial design, engineering, construction, and installation (Bai and Bai, 2012).

Operating Expenditure (OPEX) is the expenses incurred during the normal operation of a facility, or component after the installation, including labor, material, utilities, and other related expenses. OPEX contains operational costs, maintenance costs, testing costs, and other related costs (Bai and Bai, 2012).

Bai and Bai (2012) state that *"the cost of an HXT is much higher than that of a VXT; typically the purchase price of an HXT is five to seven times more"*. This contradicts the OneSubsea (2015) TST, there it is stated that the VXT and DVXT involves the most CAPEX, as seen in Table 5.1. The main contributing factor of this is the tolling and riser investments. This view is confirmed by

Norwegian Oil & Gas (2012) which state that during installation *"a HXT reduces the amount of equipment needed, time, and cost"*.

The DVXT this is a more complex tree with more parts than a VXT. The expensive special dual bore riser that a VXT requires is not necessary for a DVXT. The total CAPEX is not public, but it can be assumed that the tree itself is more expensive than the VXT. It can also be assumed that the tooling investments for a DVXT are much lower than a VXT, similar to a HXT.

The OneSubsea (2015) TST favors the VXT and DVXT if OPEX is critical. This is because of the cost from wireline plug installation or removal on a HXT. On the other hand the HXT has much lower cost from retrieving the tubing. The OPEX is therefore entirely dependent on what type of failures that are expected in the well.

The DVXT may have a lower OPEX than the VXT because of the THS. The THS lowers the amount of operations required during tubing retrieval.

Both the CAPEX and the OPEX is dependent on the variable factors in the subsea production system. The HXT has the lowest CAPEX, but if the required riser and tooling already are available the VXT can be favored. The OPEX depends on what type of interventions is expected in the well.

The OPEX discusses is only the cost associated with the tree and operation itself. The cost of unavailability of the production is also a large contributor. However, this is covered in the reliability analysis.

Chapter 6

Evaluation of X-Mas Tree Configurations

The selection process of a XT configuration is complex with many uncertainties. A good selection requires detailed expert knowledge of the production field being developed and the available configurations.

The selection seems obvious with the statements from Bai and Bai (2012) (see Section 4.2.1), recommending a VXT for a gas well and a HXT for an oil well. However, the introduction of a more complex tree that incorporate other benefits, make the selection more difficult. In addition for shallow water the advantages of the HXT on tubing retrieval may be negligible and the VXT the best choice even for oil wells.

A key point in the selection process is good data. Good data combined with a RAM analysis form a good foundation for the selection. Good knowledge of the subsea production system and the oil/gas field is also important in establishing a realistic model to support the decision.

Molnes and Strand (2007) found that the choke valve and the SCM were the main XT components to fail. Both these components are the same and independent of the different XT configurations. The low reliability of those components is solved through them being easy to retrieve and replace with a smaller intervention vessel.

Lee et al. (2004) (see Section 3.2.1) had through a RAM analysis found the main components to lower availability to be the wellhead and SCM. In choosing between the configurations there is no influence on the SCM.

The interesting part from Lee et al. (2004) is the finding of the wellhead connector as a component reducing system availability. This could have an impact on the selection of XT configurations. As stated in Section 4.3.2 the HXT may have a higher strain on the wellhead connector than the other XT configurations due to the combined height of the HXT and BOP during interventions. This phase is also critical since in would often imply that the dangerous procedure of tripping out tubing is being conducted.

The DVXT may seem like a good choice despite of the well type. It induces less strain on the wellhead compared to the HXT and is more maintainable than the VXT. The main problem with the DVXT can be the increased installation time due to the extra number of connectors. The DVXT is also a more complex system; simplicity in design increases the reliability and the DVXT may therefore have worse inherent reliability than the VXT and HXT. This may be overcome with the technology advances and the increased maintainability of the DVXT.

The author recommends that the end result of the decision process is made on the basis of a RAM analysis. For wells where many or few tubing interventions are expected a RAM analysis may not be necessary. In all other wells a RAM analysis should be conducted. Then probably the DVXT or other monobore XTs would more often be the best choice. This should not be unexpected since these XTs are the new generation and is being developed to give better performance.

Chapter 7

Summary and Recommendations for Further Work

7.1 Summary and Conclusions

The focus of this thesis is to provide input for choosing the optimal XT configuration for a subsea production system.

Throughout this thesis many different aspects of XTs are described and discussed through literature studies. This is the first objective of this thesis.

The second objective in this thesis is to describe the main functions, components and the reliability of those components. The functions are described in Section 2.1, they are also modeled as functional block diagrams in Section 2.1.1. The subsea XT is used to direct, regulate, and stop the flow from or to a well.

The main components and their reliability are described in Section 2.2. The functions of a XT are achieved through several valves, mainly the production master valve, wing valve and the choke valve. Other main components of the XT are the SCM and sensors.

The choke valve has the worst inherent reliability of the components on a XT. Because of this the choke valve is designed for easy retrieval. The choke valve could also be placed in a separate module together with some of the sensors. These are the sensors that are expected to require replacement either due to failures or the changing characteristics of the well. This module is called a FCM and is placed on the XT and easy to retrieve by a small intervention vessel. The

SCM is the XT component with the second worst reliability. Similar to the FCM, the SCM is a module that is easy to retrieve and replace. Modularization is a good method of improving system maintenance of unreliable components.

Objective three is to describe the different XT configurations and how they affect the reliability of the subsea production system. The configurations are described in Section 2.3. There are two main configurations which are the VXT and the HXT. A third configuration is also described; the DVXT is a modified version of the VXT. The main differences are how the main valves are placed and how the tubing with tubing hanger is installed. The DVXT is different from the VXT because of the THS. The THS is installed on the wellhead, and then the tubing hanger is installed and hung in the THS. The DVXT can then be installed on top of the THS in the same way a VXT would be installed on the wellhead.

Objective four is to evaluate the reliability data and models that are used to assess the reliability of a subsea XT, this is done in Chapter 3.

MTTF is the most used performance indicator of subsea reliability. The exponential distribution is the most frequently used model of a subsea components lifetime. This assumes constant failure rate during the useful life period of a component, then the failure rate is constant proportional with the MTTF. It is important to note that the *"MTTF is merely a performance indicator, not a lifetime prediction figure"* (Molnes and Sundet, 1993).

The subsea production system is maintainable; the main reliability measure is then the availability. The availability consists of the inherent reliability, maintainability, recoverability, and the maintenance support performance.

A good and frequently used method to analyze the availability of a subsea production system is through RAM analysis software. It uses reliability block diagrams, flow diagrams, and Monte Carlos next event simulation to simulate the lifetime and the availability of the subsea production system.

RAM analysis is dependent on quality reliability data and expert knowledge on the system to give a usable output. The sensitivity and uncertainty of assumptions should be considered. Lesser quality data may still be useful if used correctly and the uncertainties are managed.

In a RAM analysis the inherent reliability is just one piece of the puzzle. The failure impact is just as important. The wellhead connector is an example of this; it has high reliability, but will have a large impact on the availability of the well if it is damaged.

Two main sources of reliability data for subsea components are OREDA (2009) and Molnes and Strand (2007). There is some disparity between the two data sources. This could relate to how, from when, or from where the data are collected.

When applying component reliability data in a RAM analysis, this often give a lower availability than experienced in real life. This most likely relates to the same problems experienced in the disparity between the different reliability data sources.

A RAM analysis may still prove useful if these problems are handled correctly. Expert judgment can be used to calibrate the data so that the model fit the real life scenario. The model and analysis can then be used to optimize the reliability of the design.

OREDA (2009) distinguishes between data collected from wells with a HXT and VXT. A lower MTTF is recorded for the VXT, this may relate to older generation VXTs installed. Understanding the quality of the data is difficult and decisions should not be taken solely on the basis of data straight form the OREDA handbook.

Objective five is a reliability assessment on the differences between the XT configurations. An assessment consists of an analysis and an evaluation. A qualitative analysis is done in Chapter 4 and the evaluation is conducted in Chapter 6.

A key difference between the XT configurations is the maintainability of the tree and the tubing. Wells that is expected to have many tubing failures should be equipped with a HXT and a VXT should be on a well with few tubing failures. This is mainly due to the order of which the components are installed as the HXT allows the tubing to be retrieved without retrieving the tree and vice versa for the VXT.

A failure on the wellhead connector will have a large impact on the availability. Interventions on the HXT are done with a BOP on top of the HXT. The height of both these components puts more strain on the wellhead than the other XT configurations. Tripping out tubing is one of the more dangerous operations in a well; this combined with the extra strain on the wellhead may cause bad consequences. This may give an advantage for the VXT in a risk perspective.

A XT with a FCM will have improved maintainability. The FCM adds leak paths and makes the design more complex. The HXT is the configuration that would benefit the most of a FCM. The VXT and DVXT are easier to retrieve and may have the benefit of a simpler design without the FCM.

The DVXT is more maintainable than the VXT and does not have the challenges of the HXT with the wellhead. This configuration may be a good choice of configuration for wells with a medium amount of tubing failures. The DVXT is more complex and has more leak paths than the other two configurations. The DVXT may have a higher infant mortality because of this.

Objective 6 is to describe and evaluate what should be assessed when selecting a XT configuration for a new subsea well. Some factors that should be considered are described and discussed in the qualitative analysis in Chapter 4. Some non-reliability factors are described in Chapter 5.

As discussed in Section 3.2.1, Drakeley et al. (2001) suffered from limited field experience of new technology. Drakeley et al. (2001) concluded that if data and model uncertainties are handled a RAM analysis may still contribute to better design and reliability.

The expected failure rate of the tubing, the failure rate of the wellhead with different XT configuration, and whether to have a FCM or not are important reliability drivers that can be analyzed in RAM analysis software.

CAPEX and OPEX are also important factors in the decision process. The overall life cycle cost is difficult to estimate. One result from the RAM analysis is the OPEX cost; this could easily be combined with CAPEX to find optimal XT configuration from a cost perspective.

OneSubsea (2015) help their customers choose XT configuration with a TST. This gives a basic indication of which configuration to choose for a well.

A RAM analysis would give an overall look on the reliability and life cycle cost of the subsea production system. RAM analysis software is able to process the many varying factors that impact the optimal XT configuration for a subsea production system and should be the foundation of the decision process.

7.2 Discussion

The diversity of factors involved in subsea production systems make a general statement on the optimal XT configuration hard to formulate. In some parts of the industry the factors of configurations selection is well known. As stated in the Limitations (Section 1.3), the limited open research and data available are a limitation for this kind of research and has limited the result of this thesis.

7.3 Recommendations for Further Work

The next step after this thesis may be to conduct a quantitative RAM analysis using software described in Section 3.2.1. It should investigate the impact of tubing failure on the cost and availability of a subsea well with different XT configurations. A finding may be an intersection between tubing failure rate and the optimal XT configurations. A base case scenario of a subsea production system should be established. Then three different setups with the three XT configurations should be established. The failure rate of the tubing can then be adjusted. The availability and cost could then be assessed as the tubing failure rate is adjusted.

Another topic of further research can be the effect that a HXT and BOP has on the wellhead. As discussed in Section 4.3.2 the failure rate of a wellhead with a HXT may have a lower level of availability and safety than a VXT. This could be researched further, a thorough review of failure data and loads on the wellhead is recommended. The focus could be on wellheads and the different XT configurations that are installed on them. A deeper look into more detailed OREDA data may provide some results on this topic.

Appendix A

Acronyms

BOP blowout preventer

CAPEX capital expenditures

TST tree selector tool

DVXT deepwater vertical x-mas tree

FCM flow control module

GE General Electric

HXT horizontal x-mas tree

IDEF0 integration definition 0

MTTF mean time to failure

OPEX operating expenditure

OREDA offshore reliability database

PMV production master valve

PWV production wing valve

RAM reliability, availability, and maintainability

RAMS reliability, availability, maintainability, and safety

SCM subsea control module

THS tubing head spool

VXT vertical x-mas tree

XT x-mas tree

Appendix B

Definitions

Blowout an uncontrolled flow of fluids from a wellhead or wellbore (Holand, 1997).

Conductor housing is the top of the casing conductor, the casing conductor is installed through the temporary guide base, either by piling or drilling, and provides an installation point for the permanent guide base and a landing area for the wellhead housing (Bai and Bai, 2012).

Jumper a short pipe connector that is used to transport production fluid between two subsea components, for example, a tree and a manifold (Bai and Bai, 2012).

Lower marine riser package a device similar to a small BOP attached to the tree mandrel used for emergency well control and riser disconnect when running, retrieving or working over a dual bore tree (Richbourg and Winter, 1998).

Manifold an arrangement of piping and/or valves designed to combine, distribute, control, and often monitor fluid flow (Bai and Bai, 2012).

Permanent guide base is installed on the conductor housing, establishes structural support and final alignment for the wellhead system. The permanent guide base provides guidance and support for running the BOP stack or the subsea tree (Bai and Bai, 2012).

Production tubing the tubing through which the production fluids are delivered from the reservoir to the production tree (Richbourg and Winter, 1998).

Tubing see production tubing.

Tubing hanger a component of the wellhead system for supporting the production tubing in the well (Richbourg and Winter, 1998).

Well barrier envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation, or to the external environment (NORSOK D-010, 2013).

Well integrity application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids and well fluids throughout the life cycle of a well (NORSOK D-010).

Wellhead a structural and pressure-containing anchoring point on the seabed for the drilling, casing strings, and completion systems (Bai and Bai, 2012).

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