FACULTY OF SCIENCE AND TECHNOLOGY

MASTER'S THESIS

Study programme/specialisation: **MSc Petroleum Engineering, Drilling and Wells**	Spring semester, 2020 Open
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Title of master's thesis: **Rigless Tubing Retrieval for Plug and Abandonment and Slot Recovery Operations on the Norwegian Continental Shelf**	
Credits: 30	
Keywords: **Plug and abandonment, Light Well Intervention, Subsea Wells, Tubing retrieval, P&A Technology, Slot Recovery.**	Number of pages: 114 Stavanger, 15. June 2020

Abstract

The conventional way of performing permanent P&A operations on the NCS have been with the use of a drilling rig. It is believed that this is not the optimal unit for the purpose, as they are costly to run with day rates up to 6,5 MNOK and being massive and therefore slow to relocate. The rigs are in addition not primarily made for performing P&A operations and are therefore not optimized with regards to layout and machinery. The solution that the industry has been moving towards the past years have been the vessel, which have significantly lower day rates. A Riserless Light Well Intervention (RLWI) vessel may have day rates at around 2 MNOK while it also has lower traveling time between the wells. If equal efficiency of the operations may be obtained with the use of vessels, it is observed that there are substantial amounts of money to be saved.

There are limitations and challenges related to being able to fully complete a permanent P&A operation without the use of a rig, but it is believed that progress is being made as the industry is working towards the same goal. This thesis will elaborate on how Equinor have approached rigless P&A in their company. It covers one of Equinor's most recent projects within rigless P&A, which is to be able to pull production tubing in open sea with the use of an RLWI vessel. The thesis will cover the technical requirements related to the project and the proposed solutions. The operations are expected to be executed on candidate wells during 2021.

Acknowledgements

During the work with this thesis I have been given support and guidance from many individuals. Therefore, I would like to use this opportunity to share my gratitude to those who have helped me along the way.

I would like to thank my supervisor, Dr. Jan Aasen, for providing me with assistance and feedback throughout the work with the thesis. He has been available when needed and have contributed with relevant and valuable information when called upon.

I would also like to show my gratitude to my external supervisor from Equinor, Steinar Strøm, who has given me the opportunity to study such an interesting subject. He has, during the abnormal times caused by the COVID-19 pandemic, been readily available and provided me with valuable documentation and feedback when requested. I would also like to thank Equinor for giving me the chance to utilize their offices and equipment during my time working on the thesis.

Support have also been given by various service companies. Among those to be thanked are TIOS, PSW, TGT Technologies, GA Drilling and Enhanced Drilling.

Finally, I would like to thank my wife, Ingrid, for supporting and motivating me throughout this challenging project, as well as my daughter for giving me something else to think about when needed.

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List of abbreviations

BHA	Bottom Hole Assembly
BOP	Blow Out Preventer
CC	Control container
CCL	Casing collar locator
CT	Coiled Tubing
DHSV	Downhole Safety Valve
DP	Drill pipe
DP	Dynamic positioning
ECD	Equivalent circulating density
EFL	Electric Fly Lead
EQD	Emergency quick disconnect
FAT	Factory Acceptance Testing
HFL	Hydraulic Fly Lead
HISC	Hydrogen induced stress cracking
HMI	Human machine interface
HMV	Hydraulic master valve
HP	High pressure
HPHT	High pressure and high temperature
HSE	Health, safety and environment
HT	High temperature
HXT	Horizontal Xmas tree
IMR	Inspection, Maintenance and Repair
KV	Kill valve

LFS	Low force shear
LLP	Lower lubricator section
LP	Low pressure
LS	Lubricator section
MEG	Methanol and Glycol
MHT	Module Handling Light Tower
MMV	Mechanical master valve
MOU	Mobile Offshore Unit
MQC	Multiple quick connector
NCS	Norwegian continental shelf
NORSOK	Norwegian Petroleum Industry Standard
P&A	Plug and abandonment
PAF	Plug and Abandonment Forum
PBR	Polished bore receptacle
PCH	Pressure Control Head
PFD	Probability of failure on demand
PLC	Programmable logic controller
PMV	Production master valve
PREN	Pitting resistance equivalent number
PTIL	Norwegian Petroleum Safety Authority
PWC	Perforating, washing and cementing
PWV	Production wing valve
QAM	Quadrature Amplitude Modulation
RCT	Radial cutting torch
RIH	Running-into hole

RLWI	Riser-less Light Well Intervention
ROP	Rate of penetration
ROV	Remotely operated vessel
SDM	Subsea Distribution Module
SEM	Subsea electronic module
SIF	Safety instrumented functions
SIL	Safety integrated level
SIS	Safety integrated functions
SIT	System Integrations testing
SIWHP	Shut-in wellhead pressure
SJA	Safe Job Analysis
SNL	Spectral noise logging
SPM	Subsea pump module
SRS	Safety requirements specifications
SSD	Subsea Shut-off Device
SSR	Shear seal ram
SUT	Stack-up test
SV	Swab valve
TH	Tubing hanger
THMRT	Tubing hanger mechanical release tool
TSW	Treated sea water
UTH	Umbilical termination head
VOCS	Volume control system
VXT	Vertical Xmas tree
WBSR	Wireline Blind Shear Rams

WCP	Well Control Package
WHIM	Wellhead injection module
WL	Wireline
WOW	Waiting on weather
XLOT	Extended leak-off test
XMT	Xmas tree

1 Introduction

Since the beginning of the Norwegian oil adventure in the sixties, thousands of wells with different purposes have been drilled on the Norwegian continental shelf (NCS). Around sixty years later in 2020 we are facing a tough economical challenge in the Norwegian oil industry, as an increasing amount of the wells are approaching their end of their lifecycle and will have to be permanently plugged and abandoned (P&A). Back in 2014, the total amount of wells that needed to be plugged and abandoned on the NCS were estimated to be over 3000. [1] Since then, between 200 and 250 wells have been drilled on a yearly basis in total, which means that this number have increased to over 4000 wells. [2] In Norway, the laws and regulations regarding P&A determines that as much as 78% percent of the overall cost of the P&A operations shall be indirectly covered by the state.[2] It is therefore vital that the industry develops both the most time- and cost-efficient solutions achievable to perform P&A operations. The industry believes that a transition into rigless P&A operations may be a large contributor to reducing the P&A related costs. However, to realize this, there are still engineering and technological challenges that needs to be solved.

Equinor have decided to encounter this challenge with a step wise approach by gradually extending the scope of what P&A operations that will be executed rigless. Solutions for completing pre-P&A operations rigless are already in place. The next step in the process will be to perform rigless production tubing retrieval on subsea wells. When developing systems that is to be used for specialized operations such as tubing retrieval, it is important that the systems are generalized with respect to the different equipment and solutions that are utilized in the area where operations are planned to be executed. Examples of critical variables may be pulling capacities required, clearances in templates and measurements of the expected tubing.

This thesis will elaborate on Equinor's approach to rigless P&A and challenges and developments of solutions related to rigless tubing retrieval. Both new technology and engineering of new solutions will be presented. The thesis will also provide some general information about subsea wells, in addition to information about the standards that are followed during the described developments. Chapter 2 to 4 will mainly consist of background information relevant to the rigless tubing retrieval operation that is to be presented in the main chapter of the thesis, chapter 5.

2 Subsea well system

As the rigless tubing retrieval operations are performed on subsea wells, this chapter will be used to give a brief overview to various relevant subsea well system components. The wellhead (WH) in addition to the Xmas trees (XMT) are the interface points for the well control equipment that is to be installed during the tubing retrieval operations. [3]

2.1 Wellhead

The subsea wellhead is a key element in the subsea well systems. The wellhead system provide means to hang off and seal off the casing used while drilling a well. Further, it acts as a pressure containing element while it also provides a structural base and connection point between the well and well control equipment such as Blow Out Preventor (BOP) and XMT. As a result of this, the wellheads are exposed to both high and variable mechanical loads. In addition to this, the WH also accommodates casing strings, which is exerting more loads on the WH structure by means of heavy weight and temperature effects. Due to the loads discussed above, wellheads are highly exposed to risk of fatigue. [3]

2.2 Subsea Xmas trees

A subsea XMT, is a unit installed on top of the wellhead and contains pressure while also controlling and monitoring the flow of fluids into and out of the well. Briefly described, the unit is an assembly of various valves which have the function of controlling, testing, regulating, servicing or choking the flow of fluids coming up from a well. [4]

Some of the main functions of a subsea XMT are listed below. [5]

- Pressure vessel for flow and pressure during completion and production
- Accommodation of the following systems and elements:
  - Active well barrier elements
  - Flow control elements
  - Injection system
  - Monitoring systems
  - Production control systems
  - Downhole control systems
  - ROV interface panels.

There are in general two types of subsea XMTs, namely horizontal and vertical. The main differences between these trees are seen in the valve configuration, in addition to where the tubing hanger is accommodated. The valve configuration differences are illustrated in the figure below. [3]

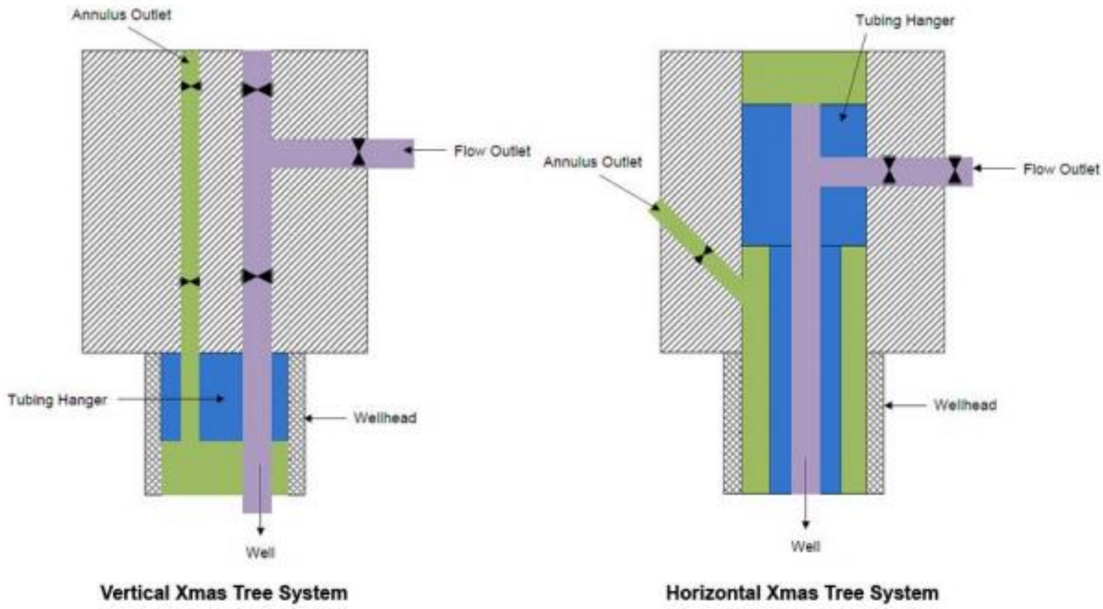

Figure 2-1: Vertical vs Horizontal valve configuration in XMTs. [6]

2.2.1 Vertical Xmas tree

For vertical XMTs the tubing hanger, accommodating the tubing, is installed in the wellhead and therefore prior to installation of the tree. This means that the tubing hanger, with the attached tubing, will not have to be retrieved prior to retrieving the vertical XMT (VXT). As a result of this solution, the tubing hanger and the tree are a dual bore configuration. To open communication between the production/injection side of the tree and the annulus a crossover valve is installed. The other main valves that the VXTs consist of are the swab valve (SV), kill valve (KV), production wing valve (PWV), hydraulic master valve (HMV) and the mechanical master valve (MMV). The HMV and MMV are often referred to as upper and lower master valves. [3]

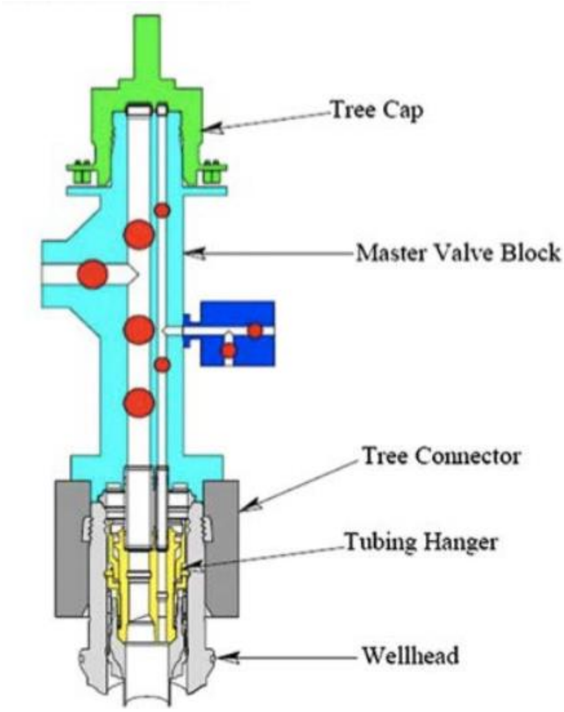

Figure 2-2: Vetrical Xmas tree. [7]

2.2.2 Horizontal Xmas tree

Contrary to the VXTs, the horizontal XMTs (HXT) have the tubing hanger accommodated in the tree structure. Effectively, the tubing hanger and the HXTs are mono bore. As the tubing is accommodated in the tree, tubing will have to be retrieved prior to retrieving the HXTs. These trees will not have valves running in the vertical direction. Instead, crown plugs are installed to act as barriers during production or injection. Having no vertical valves, allows for larger tubing sizes to be used. There will in addition be full bore access to the well, which is favorable. The projects and examples given in this thesis takes basis in use of HXTs. In addition to the crown plugs there are horizontal valves in the HXTs. The main valves are the production master valve, production wing valve, annular master valve, annular wing valve, work-over valve and the crossover valve. [3,4]

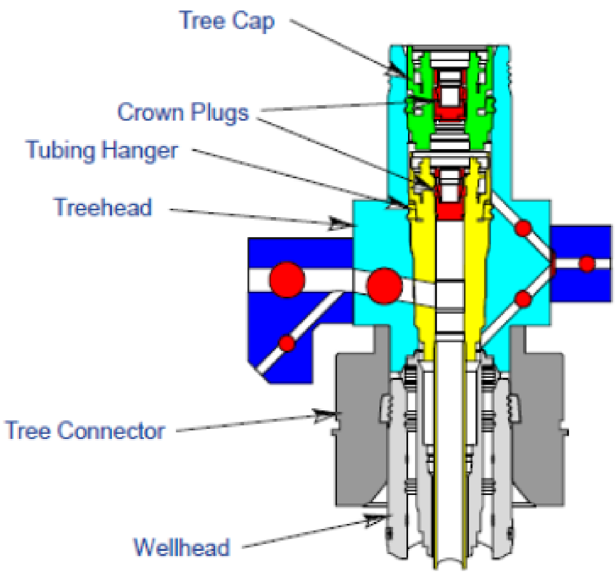

Figure 2-3: Horizontal Xmas tree. [7]

2.3 Casing and tubing

Casing and tubing strings are two of the main components when constructing a well. These components along with their main functions will be briefly described in the following subsections. [8]

2.3.1 Casings

Casings are the major structural component of a wellbore system, as is has multiple important functions. The main functions are:

- Maintaining borehole stability
- Preventing contamination of water sands
- Isolate water from surrounding environment and producing formations
- Acts as a well barrier element during drilling, production and workover operations

In addition to the functions mentioned above, it also provides the locations for the installation of blow out preventers, wellhead equipment, production packers and production tubing. The casing setting depths, grade, size and connector types determine the cost of the casing, which usually is assumed to be the major part of the overall cost of a well. There are generally five types of casings: Conductor casing, surface casing, intermediate casing, production casing and production liner. [8,9]

2.3.1.1 Conductor casing

The first casing that is installed in a well is typically the conductor casing. The main purpose of this casing is to establish a vertical path for the drill bit for the initial drilling. In addition, it provides isolation against unconsolidated formations below the seabed. This casing will also support and accommodate the surface casing and wellhead. [9]

2.3.1.2 Surface casing

When the conductor casing has been set and the next target depth has been reached the surface casing may be installed. This casing shall be fully cemented. The main purpose of this casing is to isolate weak formations down to a depth where the integrity of the formation is sufficient to ensure control if abnormally pressured zones are encountered in the following section. It will also accommodate the wellhead and support the BOP. [9]

2.3.1.3 Intermediate casing

After fully cementing the surface casing, the intermediate casing may be installed. In wells with weak zones, lack of stability or abnormally pressurized zones multiple intermediate casings may be required. In addition, the intermediate casings isolate all formations up to the surface casing shoe, to enable for drilling the next hole section safely. The intermediate casing shall be cemented above the previous casing shoe or 200m above intermediate shoe. [9, 10]

2.3.1.4 Production casing

The production casing is installed in order to isolate the productive zones in the well. It shall also ensure proper cementing of the annulus across the productive zones in order to prevent fluid migration along the wellbore. Further, it shall be able to withstand chemical and mechanical wear from formation- and completion fluids during the planned lifetime of the well. The design of the production casing shall also allow for further deepening of the hole if specified in the drilling program. The cementing requirements are the same as for the intermediate casing, 200m or above previous casing shoe. [10]

2.3.1.5 Production liner

The liner is a casing string that is hung off from another casing string. This is mainly done to reduce cost. However, using liners also do improve hydraulic performance while drilling deeper. The functional requirements for liners and casings exposed to production activities are the same as the integrity requirements for production casings during all phases of the productive life of the well. The liners shall be cemented up to the previous production packer.

Below a well barrier schematic with VXT, tubing hanger, casing hanger, surface casing, intermediate casing, production casing, and production liner is depicted. The illustration also includes a Downhole Safety Valve (DHSV). [10, 11]

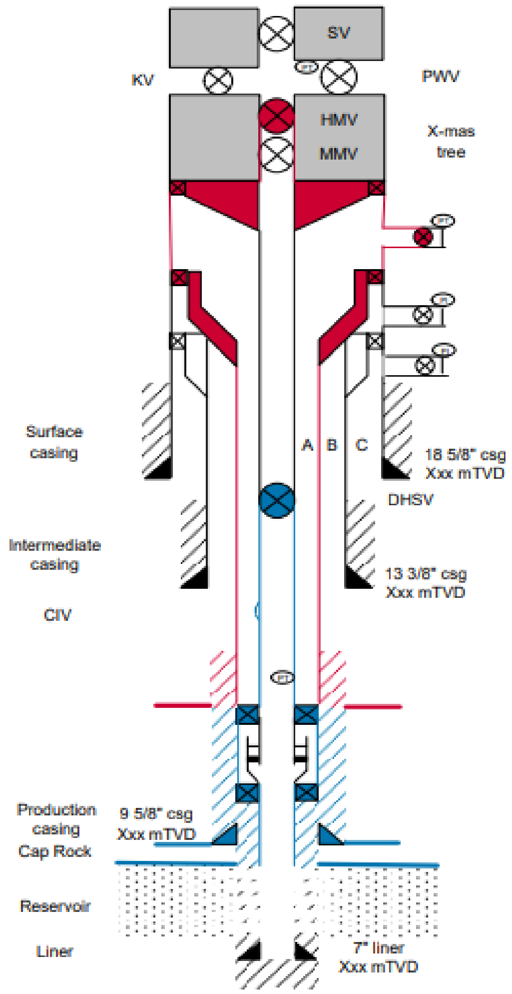

Figure 2-4: Well barrier schematic with VXT. [10]

2.3.2 Tubing

Tubing is a pipe run into the well that has the main purpose of acting as a conduit between the reservoir and the surface while also providing with protection for the casing. Tubing are most commonly utilized for production purposes but may also be used for injection of fluids into the wellbore. The tubing is highly exposed corrosion. The main types of corrosion of tubing are carbon dioxide corrosion, hydrogen Sulphide corrosion, fretting corrosion, stress corrosion cracking and microbial corrosion. However, the most common sources are carbon dioxide and hydrogen Sulphide. [12] Incompatibility between the tubing and the fluid properties can in worst cases lead to holes in the tubing which again may introduce a tubing rupture during tubing retrieval operations. [13]

When designing the tubing material for a well, the following factors shall be considered [14]:

- Environmental conditions
- Projected corrosivity of well fluids
- Minimum and maximum pressures and temperature
- Safety aspects
- Cost

Figure 2-5: Corroded production tubing due to incompatibility between fluid and tubing.[13]

The most common tubing sizes used in the NCS are 5½" and 7". Typically, in wells with high pressure and high temperature (HPHT) conditions 5½" 26ppf or 7" 35ppf tubing are used. In wells with moderate conditions 5½" 20ppf/23ppf and 7’’ 29ppf/32ppf are the most common. Therefore, the well control system must be designed to be able to operate with the mentioned tubing sizes to allow for a generalized solution.

The tubing is hung off from a tubing hanger which is sat in the WH when VXTs are used and in the tree structure itself whenever HXTs are used. Consequently, as mentioned in a previous section, tubing must be retrieved prior to retrieval of a HXT. However, when a VXT is installed the tubing must not be retrieved prior to retrieval of the tree. The two tubing hanger scenarios have been depicted in figure 2-2 and 2-3. [3]

3 Plug and abandonment

When a well reaches the point in which it is no longer cost effective to run, it is often decided to be abandoned. Before permanently abandoning a well, rules and regulations implies that the wellbore must be plugged in order to not cause environmental damage with eternal perspective. [10] This is achieved by placement of plugs with properties that comply with the rules and regulations in the area of work. The costs of these activities may in some cases be up to 25% of the total cost of drilling exploration wells in the NCS. [13] Therefore, new cost and time efficient solutions and technology related to P&A must be developed, without compromising the scope of the operation. How Equinor have approached this challenge will be described in further detail in chapter 4. This chapter will give details about important plug and abandonment definitions and terminology to serve as background information.

As safety is important in the oil and gas industry, standards and guidelines are developed in order to make sure that petroleum activities are carried out in a safe and environmentally friendly manner. Standards and guidelines will be referred to during the development of the different solutions required for the project. There therefore also be a section containing information about some of the standards that is to be used during the development of Equinor's tubing retrieval project.

3.1 Well abandonment types

As the activities in a well is decided to be ended, it is important that the status of the well is clarified in the process of shutting down the well. There are generally three different states that are defined; suspension, temporarily abandoned and permanently abandoned. [13]

3.1.1 Suspension

The state of suspension is generally used for wells that are subjected to construction or intervention, where the well may need to be left without removal of the well control equipment installed. Common reasons for this may be rough weather, workover on another well, waiting on equipment, rig skidded to do short-term work on well nearby or batch drilling, or to accommodate for pipe laying activities close to the field. [13]

3.1.2 Temporarily abandonment

The state of temporarily abandonment are given to wells where the control equipment has been removed, but where there an intention of later re-entry or permanent abandonment. Examples of reasons to temporary abandon a well may be waiting for slot recovery operations or workover, field development or re-development or waiting on permanent abandonment activities. Depending on when the next re-entry of the well is expected in addition to rules and regulations in the area of work, the temporary abandonment may be performed both with and without monitoring system which monitors the conditions of the well in order to detect any potential leakages. For this purpose, mechanical plugs, such as bridge plugs or HEX plugs, will be accepted as temporary barriers. [13,15,16]

3.1.3 Permanent abandonment

Permanently abandonment is a status given to wells that have been permanently plugged with no intention of later re-entry or re-use of wellbore. For this status to be given, the barriers in place must comply with rules and regulations for the specific area. In the NCS the standard referred to is the NORSOK-D010 standard. [13]

3.2 Well abandonment phases

The plug and abandonment operations are generally divided into three phases, regardless of well type and well location. The main objective for Equinor is to perform as many of these steps as possible without the use of a rig. This will be discussed further in chapter 4. The three phases are: Phase 0- well intervention, Phase 1- reservoir abandonment, Phase 2 – intermediate abandonment, Phase 3- wellhead and conductor cut and removal. [13]

3.2.1 Phase 0: Well intervention

Phase 0 is the first phase that is carried out in order to prepare for permanent P&A operations. This phase is already being performed by a Riser-less Light well intervention (RLWI) unit and consists of preliminary actions to reservoir abandonment such as inspection of the wellhead, verifying well bore access and identifying the tubing condition by a caliper log. The first step in Equinor plan of moving towards rigless P&A is to extend the scope of the work done by use of the rigless unit to also include retrieval of tubing in addition to a through tubing logging method that is capable of identifying leakages and cement quality behind casing. [13]

3.2.2 Phase 1: Reservoir abandonment

Phase 1 proceeds with an injection test to identify the well integrity. If the test is successful and integrity is thereby maintained, cement slurry is bullheaded into the reservoir in order to plug it. The quality shall be tested by pressure testing. Phase 1 can be classified as completed when the primary and secondary barriers against the main reservoir are set and verified according to the NORSOK-D010 standards. There is an option for both leaving the tubing in place in the well to be a part of the well barrier envelope, however due to bonding issues it is often preferred to remove the tubing. The conventional method of completing these phases have been to combine rigless units and rigs. Once the main reservoir in the wellbore have been fully isolated, the operation may proceed to phase 2. [13]

3.2.3 Phase 2: Intermediate abandonment

The scope of phase 2, intermediate abandonment, is execution of milling, retrieval of casing, setting barriers against intermediate zones and installation of the environmental plug. If the tubing were not removed in the previous phases, it may also be retrieved during this phase. Once all the flow potentials in the overburden have been secured and sealed by installation of permanent barriers, the next phase may commence. [13]

3.2.4 Phase 3: Wellhead and conductor removal

The final phase executed before permanently abandoning a well is to cut and remove both the conductor and wellhead below the surface. This is done in order to prevent any possible future incidents during other marine activities such as fishing. This is usually regarded as a marine job and not a drilling operation during work in the Norwegian sector of the NCS. [13]

3.3 Guidelines and Standards

In the oil field industry, there are several regulatory guidelines and standards that are required by the authorities to follow in order to reduce the various risks related to the offshore operations. These regulatory documents contribute to standardizing the operations by being updated as new preferred methodologies and technology are discovered. This chapter will consist of information about the content of the standards and guidelines referred to during the development of the tubing retrieval project: NORSOK D-010, OLF081, OLF 070.

3.3.1 NORSOK Standards

The NORSOK standards are standards developed by specialists within specific fields in the Norwegian petroleum industry as part of the NORSOK initiative. These standards are supported by the Norwegian Oil and Gas Association in addition to the Federation of Norwegian Industries. The NORSOK standards have the main purpose of replacing individual oil company standards and guidelines. During development of the NORSOK standards extensive references are made to international standards when necessary and relevant and the industry is frequently involved. The standards are updated with new revisions as new technologies and solutions are developed every 5 year. One of the standards that is currently being revised and set to be released in 2020 is the NORSOK D-010 revision 5. Typical changes that are made during such revisions may be changes to make the language more concise and precise, updating tables, adjusting requirements in order to comply with new technology and changing the structure of a chapter. [10, 17]

The NORSOK D-010 standard, will be the main standard referred to when creating tubing retrieval programs. This standard comprises the requirements and guidelines related to well integrity in drilling and well activities, where the guideline defines well integrity to be "application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well". [10] The chapters which have been of main relevance during development of the tubing retrieval solutions are chapter 9: "abandonment activities" and chapter 10: "wireline operations". By following the requirements and guidelines given in the standard, well integrity may be retained during the abandonment procedure.

Chapter 9- abandonment activities, covers the guidelines and requirements related to well integrity the well abandonment types discussed in chapter 3.1 of this thesis. It has the main purpose of describing requirements related to establishment of well barriers through use of well barrier elements in addition to other required features that focuses on isolating a permeable formation or source of inflow. The standard gives details on the acceptance criteria for both well barriers and well barrier elements for the various abandonment types. In addition, information on various verification and testing methods and requirements and recommended design premises during the abandonment process in order to retain well control during the abandonment process is also given. [10]

Chapter 10 comprises requirements and guidelines to retain well control during wireline operations. It describes requirements for the configuration well control equipment, tool string deployment and operational procedures. Further, it specifies various well barrier acceptance criteria in addition to well control action procedures and drills if unexpected events occur. Lastly, examples of possible well scenarios are given by means of well barrier schematics.

In addition to the NORSOK D-010 standard, other standards will also be utilized during the project development. These standards are NORSOK D-002, NORSOK D-001, NORSOK S-001, NORSOK S-002 and NORSOK M-501. The NORSOK D standards are standards related to drilling, NORSOK S are safety related standards, while the NORSOK M -501 standard gives requirements for the material coating of the subsea components installed. [10,18]

3.3.2 OLF 081

OLF-081 are guidelines developed with the main focus of increasing the safety and reduce the risks related to remotely operated pipe handling equipment. These guidelines are recommended by the Norwegian Oil and Gas Association in addition to being approved by the Managers Forum of Norwegian Oil and Gas. The guidelines were created in consultation with both the Norwegian Shipowners Association and the Norwegian Petroleum Safety Authority (PTIL). The main scope of this document is to provide guidelines that enables for practical implementation of PTIL's requirements for remotely operated pipe handling systems.

The guideline states that "all pipe handling that is possible to remotely operate shall be remotely operated as long as it increases the overall safety of the operation." If manual pipe handling solutions are used for operations where remote systems are available there shall be performed a risk analysis. Various requirements if selection of manual operated systems is chosen is defined in the guideline. The majority of the guideline contains a matrix detailing how the involved pipe handling equipment during pipe handling sub operations are recommended to be controlled. How the matrixes are filled out in order to identify if pipe handling requirements are met is shown in figure 3-1 below. Before any operations may commence, it is also important that some equipment is marked with precise labelling in order to prevent conflict or confusion with other relevant marking. Typical marked equipment is: Elevators, inserts for multi-range elevators, slips, inserts for multirange slips, lifting subs. [19]

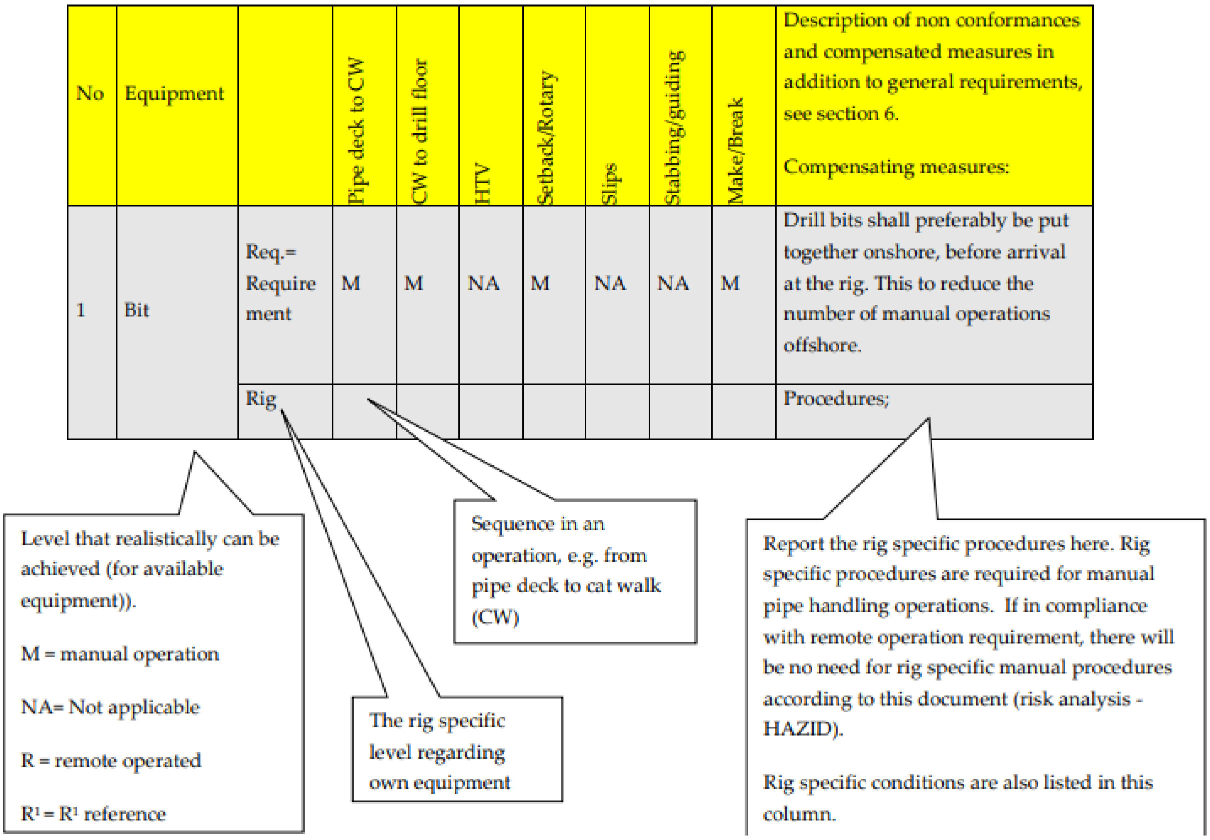

Figure 3-1: How the pipe handling matrixes shall be filled out. [19]

This guideline will be the main focus during development of the remote pipe handling system for the tubing retrieval project. The guideline specifies that pipe handling systems on new drilling unit projects shall have the objective of reducing the extent of manual pipe handling operations even further than described in the OLF-081 document itself.

3.3.3 OLF 070

The Norwegian Oil and Gas guideline number 070 is a guideline created with the main purpose of allowing for a simplified and standardized application of IEC 61508 and IEC 61511 in the Norwegian Petroleum industry. IEC 61508 and IEC 61511 are documents created to implement a risk-based approach for identification and specification of performance requirements for safety-instrumented functions (SIF). The guideline proposes performance requirements for functions that have already been identified as requirements both in the NCS and internationally that may be used together with the requirements determined by the risk-based approach. Both safety integrated systems (SIS) and other safety barriers are normally implemented in these analyses in order to obtain the required reduction of risk. [20]

The guideline gives proposed requirements for the various SIF including process shutdown, emergency shutdown, fire and gas functions, some BOP functions and specific workover functions. These requirements are presented in the safety requirements specification (SRS) section of the document. The SRS provides input to the barrier strategy document. The requirements given are based on derivations performed by estimating achievable probability of failure on demand for the various functions. This is done by use of loop diagrams and reliability data verified by experience gathered from the industry. Based on the calculated probability of failure on demand (PFD) for the functions, requirements for reaching safety integrated level (SIL) from 1 to 3 is given. [20]

The selected functions along with the required SIL and functional boundaries are presented by means of a table in the guideline. For the functions where only SIL 1 is achievable by of the current industry practises, a specific PFD requirement are given in addition to the SIL requirement in order to ensure a certain reliability of the function. These PFD may be within the range of 0.1 and 0.01. For functions where SIL 2 or 3 is achievable, the PFD requirements and calculations are given in a separate table. [20]

The OLF 070 document will be referred to and used as a guideline during development of the safety systems used for the tubing retrieval project in order to ensure that the performance requirements for the safety systems are met. [20]

4 Equinor's approach to rigless plug and abandonment

To be able to encounter the challenge of being able to permanently plug and abandon (P&A) the wells on the Norwegian Continental Shelf (NCS) in the most cost and time efficient way possible, the operating companies involved must work together. As of writing in 2020, there is agreement within the industry that P&A with the use of a vessel as the operating unit has potential to save both time and money and is therefore a subject worth researching further. Throughout this process, experiences will be gained as operations and technology are in some cases executed and tested for the first time in the NCS. It is therefore important for the development of the knowledge regarding rigless P&A, that these experiences are shared among the companies in the industry.

In 2009 a P&A forum (PAF) was established in order to promote development of and share experiences with new cost efficient and robust solutions to the P&A related challenges on the NCS. Since then there has been arranged seminars on a yearly basis, with the main purpose being to present the latest status, exchange experiences and encourage the industry to resolve various P&A challenges. A subject that has been given much attention the past years is rigless P&A. Operating companies have had several presentations requesting development in new solutions related to rigless P&A challenges and shown willingness to test out new technology. This has led to increased focus on the subject within the service companies, which shows that seminars like this are an important contributor to why the industry is moving forward.

The approach that Equinor has taken in the transition into being able to fully complete permanent P&A operations rigless, has been to divide the P&A process into segments. The segments of the operations have been projected on to a roadmap which describes what Equinor see as possible milestones to achieve within estimated time limits. The roadmap that is created for the transition from conventional P&A into rigless P&A is illustrated in figure 4-1 below. [21]

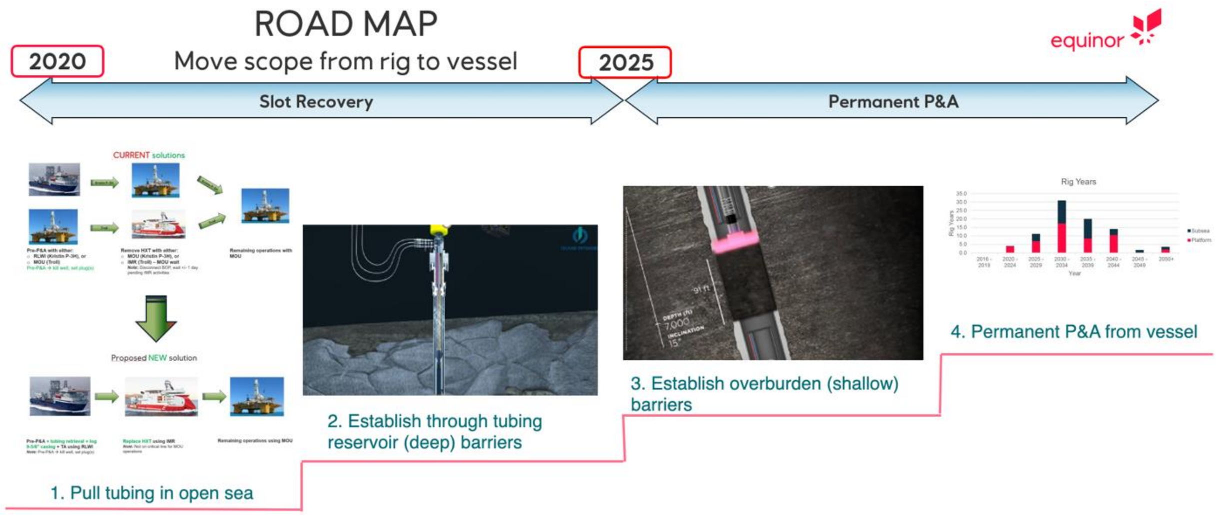

Figure 4-1: Equinor's roadmap towards rigless P&A.

Equinor has divided the transition into rigless P&A into four milestones [21]:

1. Pull tubing in open sea and establishing (Ongoing development)
2. Establish through tubing deep reservoir barriers (Planned development 2020-2025)
3. Establish overburden shallow barriers (Planned development 2025-)
4. Permanent P&A from vessel (Planned development 2025-)

From these points it can be observed that Equinor's approach is to gradually expand the scope of the work done with vessels until the main goal of fully rigless P&A operations is achieved.

4.1 Pull tubing in open sea and establishing deep barrier

4.1.1 Pull production tubing

To be able to pull tubing in open sea with the use of a vessel three main challenges have been identified. The first challenge is to be able to construct a Subsea Shut-off Device (SSD) suitable for the operation and the operating unit. Secondly, releasing the production tubing hanger will require large pulling forces which may be difficult to achieve only with the use of the existing winch system on the vessel. Therefore, development of a subsea jack, contributing with additional pulling force must be evaluated. There is also need for a device keeping control of the fluid volumes in the well during the operation due to the volume changes that will occur when the tubing is being pulled out of the well. Lastly, prior to pulling the tubing, a verified log of the production casing will be necessary in order to identify if there is sufficient cement bonding behind the production casing installed. These points will be elaborated on later in chapter 5.5 – Technical requirements.

The amount of production tubing that will be pulled depends on the well configuration, choice of barrier placement method in addition to what type of Xmas tree that is used. Since the tubing hanger in a horizontal Xmas tree (HXT) is integrated in the tree structure, tubing would have to be retrieved in order to nipple down the Xmas tree. [3] However, in cases where the production tubing is intended to be used as a well barrier element, only the tubing above the shallowest barrier will have to be retrieved. A vertical Xmas tree (VXT) is on the other hand installed on top of a separate tubing hanger structure. Consequently, the VXT must be retrieved in order to be able to pull the production tubing. Based on the tubing condition it may be partially or fully retrieved. [13] There will be a separate chapter discussing the equipment to be used and the specific runs that will be performed during pulling of tubing on a potential candidate well with a HXT in chapter 5.6.

4.1.2 Establishment of reservoir barriers

Once the tubing is pulled as specified in the P&A- program for the well, establishment of the reservoir barrier may commence. This may be done by use of an onboard cementing system combined with a through tubing barrier placement technique, in wells where it is verified that the condition of the production tubing is good. Once primary and secondary barriers against the main reservoir are installed, tested and verified in accordance to the NORSOK D-010 standard rev.4., the reservoir may be regarded as fully isolated from the wellbore and phase 1 of the P&A operation is completed. [10, 13]

4.1.3 Conventional unit selection for P&A – Subsea HXT

The current solutions with regards to selection of P&A unit within Equinor have been to either use a Riserless Light Well Intervention vessel (RLWI) unit or Mobile Offshore Unit (MOU) to execute the pre-P&A phase of the P&A operations. The pre-P&A scope generally consists of killing the well and installing temporary plugs in the well. Thereafter a MOU may be mobilized for pulling the production tubing, while the HXT may be retrieved by either the MOU already in place or an Inspection, Maintenance and Repair (IMR) vessel. Finally, the remaining operations will be performed with the use of a MOU. These are typical unit sequences for P&A, slot recovery or workover operations on subsea wells with HXT done by Equinor. Two alternative unit sequences for P&A, slot recovery or workover operations with the current conventional solutions are depicted in figure 4-2.

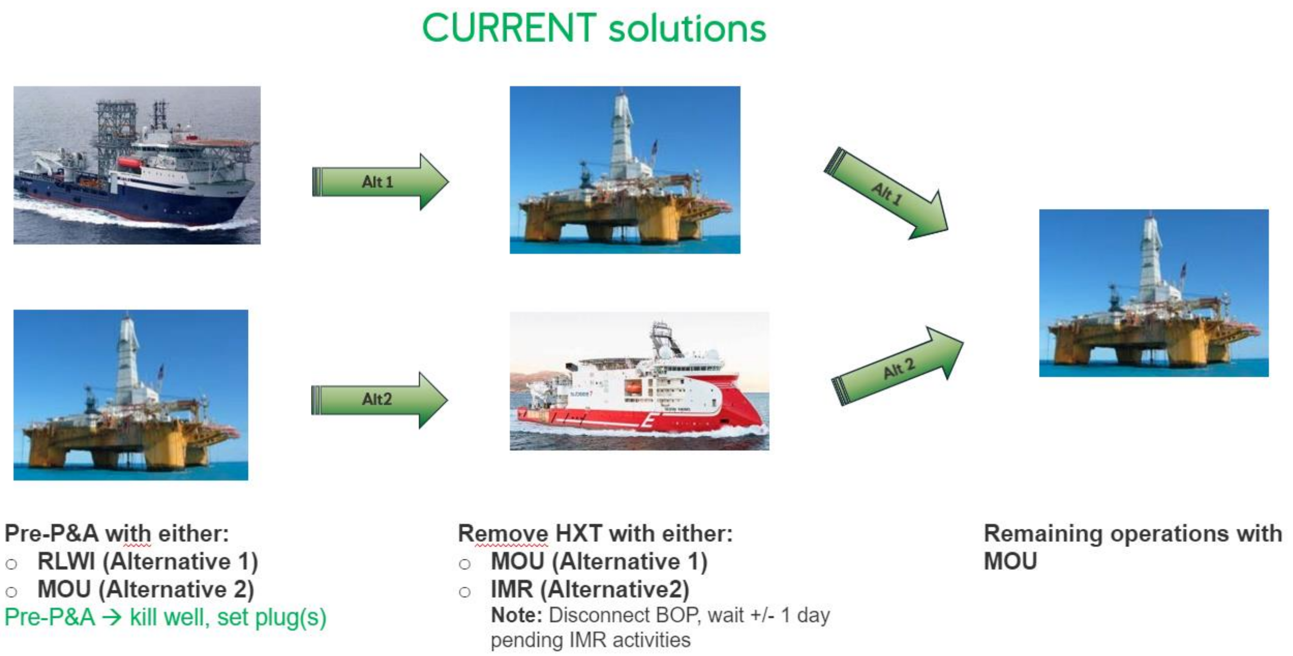

Figure 4-2: Current P&A/Slot Recovery/Workover solutions for subsea wells with HXT [21]

4.1.4 Proposed new unit selection for P&A – Subsea HXT

The first step in the transition towards rigless P&A is as discussed, an extension of the operational scope of the RLWI vessels. The road map suggests RLWI vessels should extend their scope from pre-P&A operations to include performing production tubing retrieval, logging the 9⅝" production casing and placing barriers as discussed above. The HXT will then be retrieved by an IMR, as de-mobilization of equipment would have been necessary for the RLWI vessel to be able to pull the HXT due to space limitations. It is therefore estimated that the IMR-vessels, that travels according to set schedules, is a more effective to utilize for HXT retrieval. The remaining operations will be carried out using a MOU as discussed in the previous section. Figure 4-2 illustrates the new proposal of unit selection.

Figure 4-3: Proposed new unit selection for P&A operations on subsea wells with HXT [21]

4.2 Establish deep reservoir barriers through punched tubing

The second step on Equinor's road map is an alternate method to the previously discussed step of pulling production tubing, where the tubing instead is punched at the bottom to establish connectivity to the A- annulus on the outside.

4.2.1 Barrier placement

After holes are successfully punched in the production tubing, a barrier may be established by pumping cement down through the tubing, into the holes created and into the A-annulus. The desired cement placement technique may be the two-plug method, using a tubing dart launching solution, in order to avoid contamination of the cement. [13,21] This will require that the vessel have an onboard cement pumping and mixing system with sufficient capacities. An advantage with placing the barrier through punched holes in the tubing, is the fact that no tubing must be retrieved, thereby saving rig space. Consequently, resulting in reduction or elimination of the risks of accidents related to pipe handling and reduced tripping activity, which saves time. This barrier placement technique has been tested in experiments, and it is believed that the method shall be ready for field testing during the summer of 2020. [22]

To be able to pump cement into the system, an adapter below the vessels well control package would be required. This adapter would have to be compatible with the tubing dart launching system that planned to be used in the future project. Cement mixing and pump solutions for bull-heading operations will have to be considered in addition to A-annulus barrier cementation. Once the barriers are installed, tested and verified in accordance with the NORSOK D-010 Standard rev.4., phase 1 of the P&A operation is finalized.

4.2.2 Logging method

To perform the operation discussed above fully rigless, a qualified logging method for verifying cement bonding through both tubing and casing is necessary. This was a topic discussed at the 2019 PAF seminar, and solutions were proposed. The solution for dual-string or multi-string logging that Equinor believe has the most potential and have been testing with success recently are the noise logs. These logs detect the noises emitted when gas or liquid are flowing through tight cracks in the casing, cement or formation. The noise log technology will be elaborated on at a later stage of this thesis. [23]

4.3 Establishment of overburden shallow barriers

The third step in Equinor's roadmap in the transition to rigless P&A is being able to establish barriers in order to isolate intermediate permeable hydrocarbon or water-bearing zones, in addition to the establishment of an environmental barrier. This is regarded as phase 2 of the well abandonment phases. Depending on the state of the production tubing it has either been fully removed or left in place in the well. [13] According to the NORSOK D-010 requirements a permanent well barrier shall extend across the full cross section of the well, sealing all annuli in both vertical and horizontal direction. [10,21]

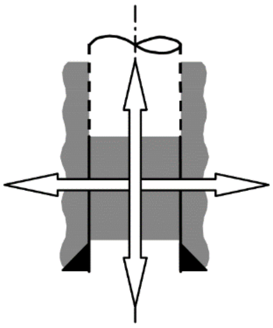

Figure 4-4: Cross sectional barrier in cemented casing. [10]

For this phase to be fully completable by use of a vessel, the two previously mentioned steps in the road map must be qualified. In addition, there will also be need for a qualified logging method that is capable of logging through tubing, tubing cement and the two following annuli. It is believed that the noise logging method discussed previously is the method with the most potential for the intermediate section as well.

Further, Equinor have identified the need for a coiled tubing (CT) based casing removal solution. Solutions that are currently being reviewed is casing milling and plasma milling.

These methods may also be used for milling the production tubing when the tubing is un-retrievable even after a successful cut is made. [24]

4.3.1 Section milling

With section milling a lot of risks and potential challenges are introduced. An example may be both the risks and the health, safety and environmental (HSE) issues that comes along with the *swarf* created during a milling operation. *Swarf* is a term used for the metal shavings created by the milling tool during the casing removal process. [13] In conventional P&A operations one of the concerns is that swarf may get stuck in mechanisms in the well control systems blow out preventer (BOP). Therefore, extensive BOP cleaning is carried out, which is time consuming. There are also requirements for the weight and viscosity properties of the fluid in order to suspend and transport the swarf to surface. These may in some cases lead to fracturing of the formation as the equivalent circulating density (ECD) can exceed the formation strength. This again may lead to substantial fluid losses and subsequently swabbing and in the worst-case scenario loss of well control. [13]

Conventional milling operations done with drill pipes are very time consuming as the rate of penetration (ROP) shall be kept under 2 meters an hour in order to create small and uniform swarf returns. By not having optimized milling parameters there is a risk of creating long swarf returns, which have a higher probability of nesting and may consequently lead to a pack-off situation. [13]

Since the coiled tubing (CT) does not have the ability to rotate in the well, section milling would need a milling device with an integrated motor to cause the tool rotation. It is expected that this device would mill slower in comparison to the conventional milling methods done with drill pipes, as the circulation rates achieved with coiled tubing are significantly lower. Equinor have been in contact with Ardyne regarding the development of a CT milling tool that utilizes a motor in the bottom hole assembly (BHA) for rotation. [25]

4.3.2 Plasma based milling

Alternatives to casing milling techniques such as plasma milling is also being evaluated by Equinor’s rigless P&A team as development on the technology is ongoing. Plasma based milling is a technique where steel is disintegrated into small enough cuttings to be circulated out of the wellbore without packing off. The plasma is created by subjecting some gases to a strong magnetic field created between the anode and the cathode of the system. [13] This creates a superheated electrically ionized gas, magma, with high kinetic energy which forms a jet cutting the electrically conductive material. In the process where the plasma reacts with the casing steel, tests have shown that differences in the thermal expansion coefficients of the metal-oxide multilayers occurs. This difference may give a potential for relatively easy hydrodynamic removal process. [13] Though, for P&A application the cuttings may be left behind in the well without being circulated out. A photo of cuttings from a laboratory test is depicted below in figure 4-6. Plasma milling technology have yet to be field tested and is therefore not yet commercially available. Equinor are in contact with GA Drilling regarding performed at GA Drillings test facilities. Equinor do not have any projects planned with GA Drillings as of writing, but they are following the progress of their work and have been providing field data and technical requirements upon request. [26]

Figure 4-5: Left: PlasmaBit BHA on a test rig. Right: PlasmaBit milling during an inhouse laboratory test [27]

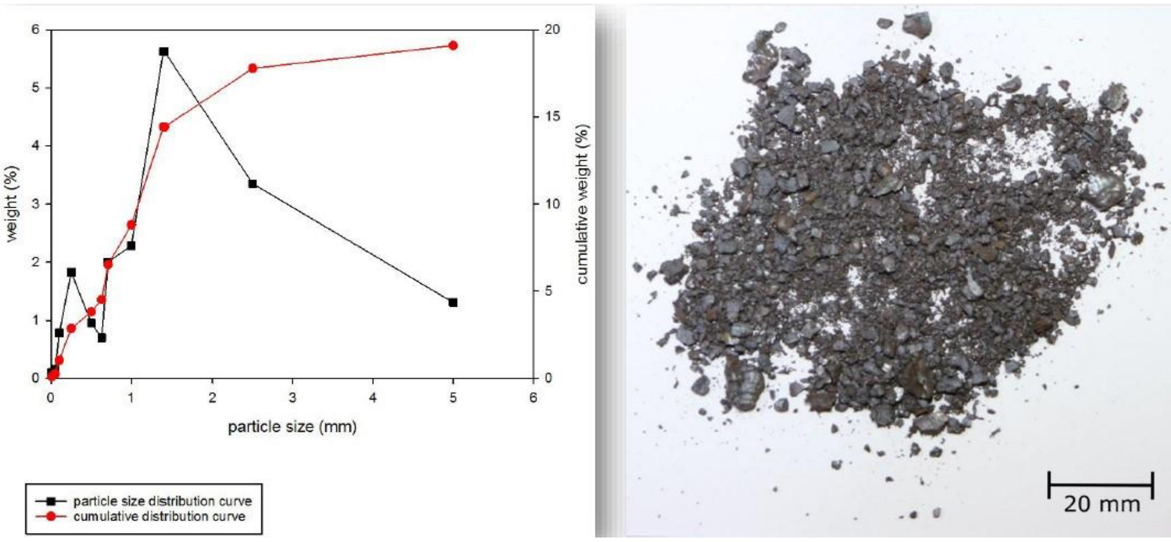

Figure 4-6: Left: Sieving analysis of cuttings, Right: Picture of cuttings from laboratory test of GA Drillings Plasmabit [27]

4.4 Permanent P&A from Vessel

Being able to fully complete a P&A operation with the use of a RLWI vessel is the final milestone in Equinor's roadmap towards rigless P&A. This will require qualification of the three previous steps. Given that a verified method of setting the intermediate barrier as discussed in section 4.3 is available, the same method may be used to set an environmental surface barrier in order to isolate the wellbore from the external environment. The main purpose of the environmental barrier is generally permanent disconnection of the open annuli that is created once the casings are cut for wellhead retrieval. When the plug is set, tested and verified, the last step in the permanent P&A operation may be performed. This step consists of the removal of the upper part of the all the casings in place in addition to the WH. [21]

4.4.1 Cutting methods for wellhead retrieval

NORSOK D-010 specifies that the WH and casings shall be removed at a depth below the seabed which ensures that there is no risk of stick up in the future. [10] In conventional P&A operations, the cut has been performed either by use of cutting knives or by using explosives.

A less risky option that has been developed in recent years is the abrasive water jet. This technique utilizes the kinetic energy of abrasive particles that is being added to a pressurized water stream. [13] The pressurized mixture thereafter enters through an umbilical and exits out of a nozzle on a manipulator creating high pressure forces. The pressures produced may vary between 50-250 MPa depending on the steel grade and thickness, while the flowrates are kept relatively low as they generally range between 40-100 liters per minute. Abrasive water jets can perform cuts through 7'' casing all the way out to a 36'' conductor. The concept of abrasive water jetting with the main components is depicted in figure 4-7. [28]

The velocity and the distribution of abrasive particles in the fluid mixture is an important factor that controls the effectiveness of the jet. A problem that may occur is blockage of the nozzles due to the grain sizes of the abrasive particles. To avoid this, flow is always kept above a certain rate during the operation. The abrasive water jet may be used with RLWI vessels which makes it applicable for rigless WH removal. [28]

When the cut is successfully performed, the wellhead may be retrieved by use of a wellhead connector.

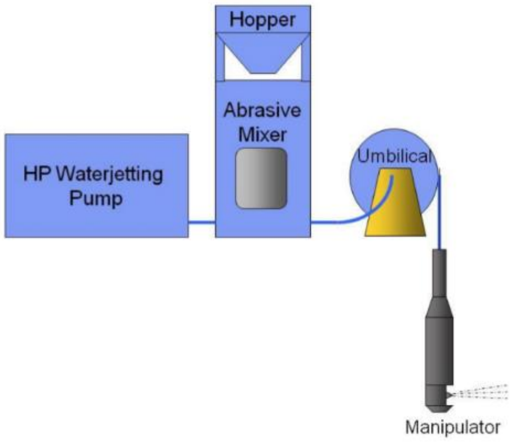

Figure 4-7: The principle of abrasive water jet cutting [28]

5 Rigless production tubing retrieval

5.1 Background

The first step in Equinor's roadmap for rigless P&A was being able to retrieve tubing in open sea with the use of a Category A Vessel. Equinor already have contracts with TIOS regarding two vessels being used for riser-less light well intervention (RLWI). TIOS were therefore contacted and asked to investigate the possibilities of using one of their vessels, Island Wellserver, for slot recovery operations during the planned 2020 RLWI-campaign. The base case that was requested by Equinor was to perform slot recovery operations on 3 specific wells in the NCS. One alternative offered by TIOS was to take basis in that all fluid in the well, both tubing and A-annulus volumes, would be displaced and pumped into the flowline leading back to the host-platform. This will be referred to as Alternative 1.

Figure 5-1: Island Wellserver before any modifications were made. [29]

A point that was brought up and identified during meetings between Equinor and TIOS was that there would be a higher potential for slot-recovery operations in the future if the vessel would be able to take returns from the well back to the vessel. If this would be achievable, there would be no need to connect onto the rigs flowlines and the fluid handling would be independent of the rig. TIOS evaluated if there were any possibility of taking hydrocarbon-contaminated fluid back to the vessel, but early investigations revealed that this would lead to a more complex operation.

When connecting to the well, the fluids in the tubing will either need be displaced from the vessel to the host-platform with the use of the subsea flowline as discussed above or be bullheaded back into the reservoir. The vessel will have the capability of bleeding off smaller amounts of gas-pockets from the top of the Xmas tree by utilizing the vessel's hydrocarbonventing system. for this case the gas received will be cold-flared to the top of the onboard tower through a 6’’ vent-line.

After the tubing fluid have been bullheaded, the vessel must displace the fluid in the A-annulus by circulating either the long or the short way. By circulating the long way, the circulated fluid is pumped down through the tubing and up in the A-annulus, which is typically performed during perf-wash-cement (PWC) jobs. The short way of circulating would therefore be to pump fluid down through the A-annulus and up into the tubing, which is a pumping method utilized when balancing the pressure while retrieving tubing out of a well. A solution that would require contaminated fluid returns to be taken back to the vessel, will be referred to as alternative 2 in the following segments. [30]

5.2 Economic evaluation

The next step in the process was to verify if it would be economically feasible to complete a tubing retrieval operation in open sea with the use of a vessel. This was done by an analytical cost estimation of the cases discussed. The analysis considered potential vessel candidates, the modifications that would be needed on the relevant vessels, estimates regarding mobilization and demobilization of equipment specifically needed for the slot recovery- operations and estimated operational time required. The modifications that needs to be made on the vessels are dependent on what operation alternative that is chosen to move forward with, and what vessel that is to be used for the project. By analyzing this information, an estimated cost summary is created by the company in charge of the vessel, in this case TIOS. [30]

The cost summary is dependent on the factors mentioned in the segment above, but it is also affected by the number of wells that will be worked on during the campaign. The initial investments are expected to be relatively high due to the extent of modifications that will be performed on the vessel in addition to the initial mobilization and demobilization of needed equipment. It is therefore relevant to do an estimate for the second year of the project and onwards, based upon multi well campaigns that may be planned in the coming years. [30]

The candidate vessels that were evaluated by TIOS for this project were Island Wellserver and Island Constructor. The vessels have similar properties with regards to existing onboard equipment and relatively similar deck layout. They are in addition both planned to be used during Equinor’s 2020 RLWI campaign as previously mentioned. Island Constructor have more storage capacity with regards to both equipment and fluid storage, while also being a newer vessel. Less modifications would need to be made compared to the ones needed on Island Wellserver. To compensate for the lack of deck space on Island Wellserver, a mezzanine deck is planned to be built, which would equate for increased modification costs. This additional deck space is planned to be used for pipe storage, so that the RLWI operations may be uninterrupted by the slot-recovery operations, while it would also reduce the mobilization /demobilization needed. [30]

The difference in upgrade and modification costs between Island Wellserver and Island Constructor is estimated by TIOS to be in the range of 6-7 MNOK. In addition to this, differences in cost during mobilization/demobilization between the evaluated vessels was considered. Estimates done by TIOS determined that mobilization costs for Island Wellserver would be in the ranges of 2- 3 MNOK higher than for Island Constructor. These estimates were based on the mobilization time required and the differences in day rates of the vessels. It was decided to move forward with Island Wellserver. Therefore, the rest of the analysis and thesis will take basis in use of that vessel. [30]

5.3 Modification requirements

In this section the modifications that will be needed on Island Wellserver dependent on which of the alternatives discussed in section 5.1 is decided to move forward with. It is worth noting that there is already an existing contract between Equinor and TIOS regarding RLWI operation for this vessel, but a slight modification of the contract would be needed as additional equipment would have to be installed. [30]

The Subsea Shut-off Device must be stored aft of the tower on the starboard side due to space limitations in front of the tower. Consequently, the lower section of the lubricator-section (LLP) will have to be removed and skidded aft of the SSD when the SSD shall be skidded onto the moonpool hatch. It is estimated that the consequence of this is 3 hours added operational time when removing the LLP, in addition to 3 hours added operational time during re-installment. This will in addition be a weather sensitive operation due to heavy lifting during installation. [30] An illustration of the skidding sequence during installation of SSD and LLP is depicted in figure 5-2.

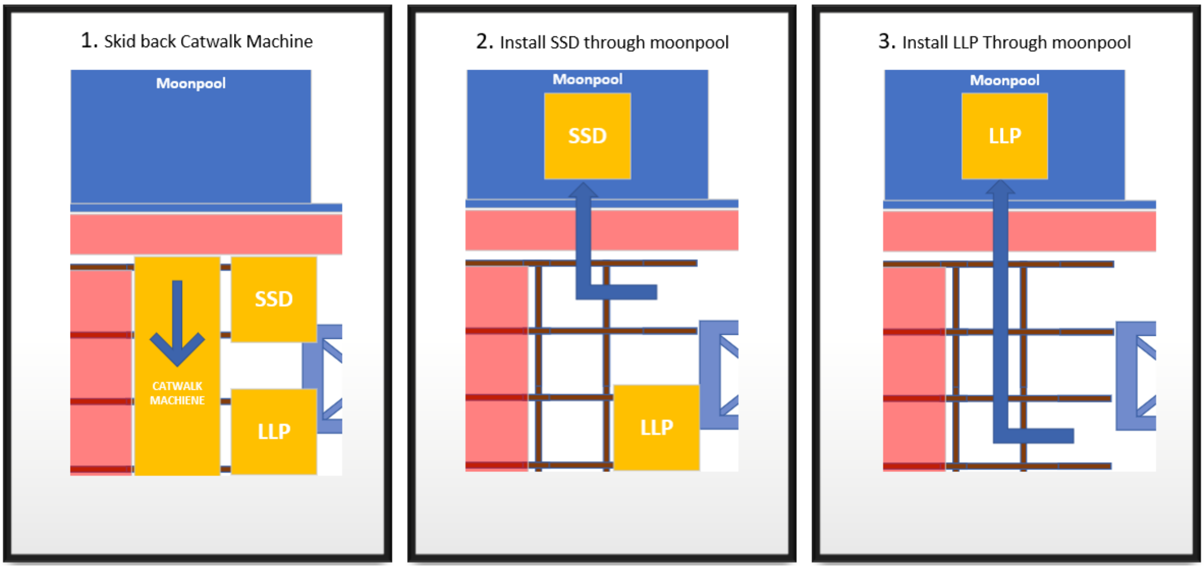

Figure 5-2: Skidding illustration during installation of SSD and LLP.

It is planned to be constructed a maintenance-platform around the SSD and LLP skids, to allow for effective maintenance. This, along with several other changes and modifications will have to be made in order to prepare Island Wellserver for being able to pull production tubing. The major modification needs for the two discussed alternative solutions are identified below.

5.3.1 Alternative 1

Since Island Wellserver have not been used for pipe-handling operations previously, the following changes/modifications will have to be implemented:

a) A new mezzanine-deck will have to be installed for storage of tubing and drill-pipe aft of the control room. The deck will be split in 3 sections, including flanges and will be fastened to the main-deck with the use of bolts. The dimensions of the mezzanine-deck will be 8m x 25m, which will result in a deck area of 200m^2, with a storage area of 187m^2. The deck will be elevated 3 meters above the main-deck. The storage-weight capacity of the deck is estimated to be 220 tons, and if additional storage-weight is required for the operation the wooden deck on starboard side may be used.

b) Utilities for the various pipe handling equipment will be provided from existing utility stations. The main utilities are the catwalk-machine, iron-roughneck and power-slips. In order to comply with "081 – Norwegian oil and gas' recommended guidelines-remote pipe handling", additional permanent piping and signal cables will have to be installed.

c) There will be need for a new lifting-yoke. The pipe and tubing will be handled by a port-side crane between the catwalk-machine and the mezzanine-deck. The existing lifting-yoke that have been used on other vessels by TIOS will not be suitable as Island Wellserver have a longer arm on the crane. A lifting-yoke from another Island Offshore project is planned, and the required interfaces and utilities will be installed on this yoke.
d) A Subsea Shut-off Device with a simplified control system, operate from the tower-cabin will need development. Details on this will be discussed in chapter 5.5.1.
e) Potential reinforcement underneath the main deck.
f) Repositioning of tower turn-over top-sheave and prepare a double-fall sheave installation. The proposed sheave solutions are depicted in figure 5-6 and 5-7.
g) Modification and strengthening of the moonpool hatch for false rotary table installation.
h) Modification of the main winch software due to the new winch configuration.

Figure 5-3: Sketch of the main-deck with Mezzanine-deck installed. [31]

Figure 5-5: Catwalk machine installed on Island Valiant [31]

Figure 5-6: Pipe trolley on Island Frontier. [31]

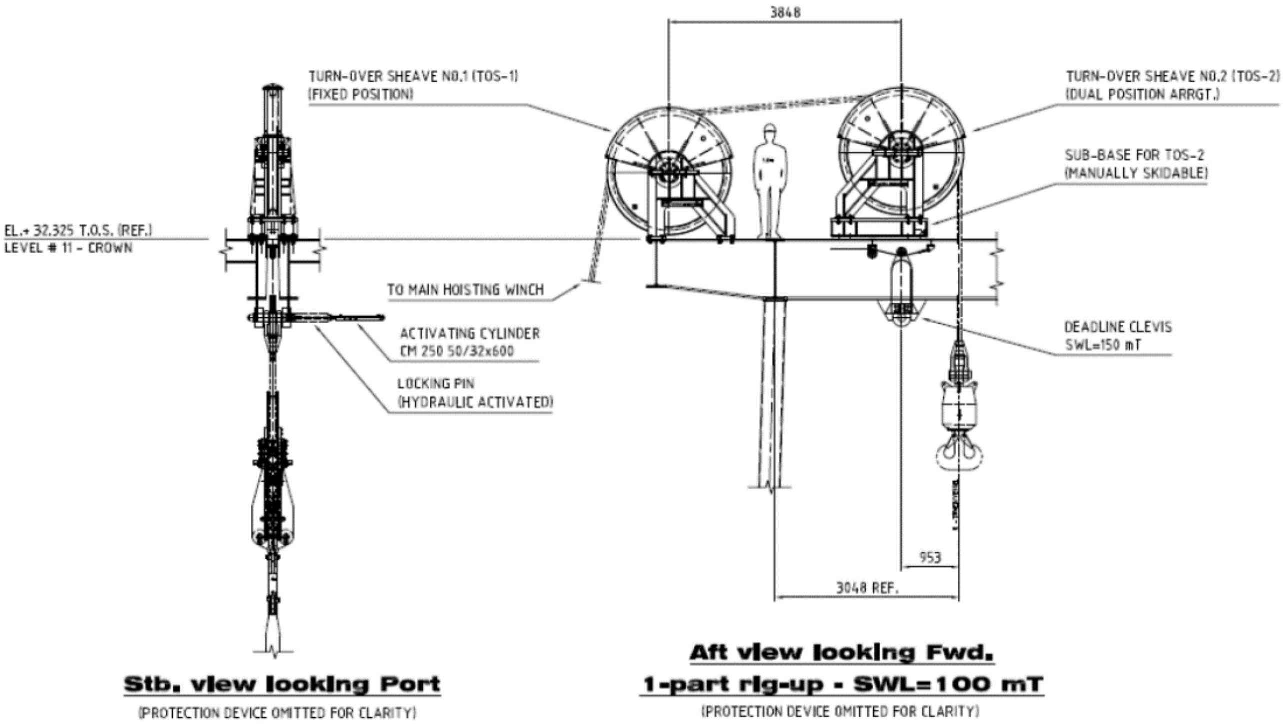

Figure 5-4: Turn-over sheave configuration. Pulling capacity: 100 tons. [31]

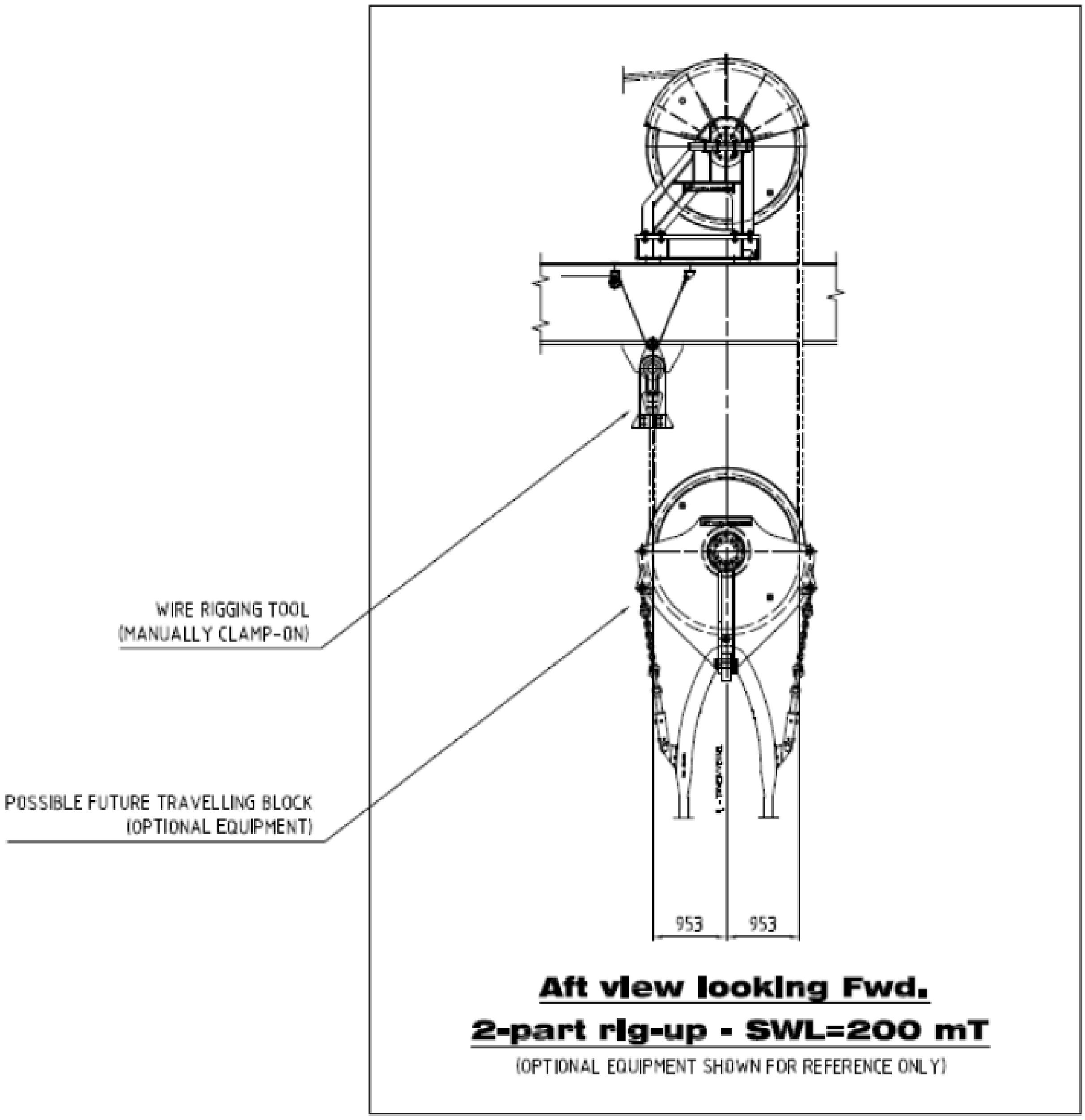

Figure 5-7: Double-fall sheave setup. Pulling capacity: 200 tons. [31]

5.3.2 Alternative 2

The second alternative requires the modifications discussed in the previous section in addition to the modifications listed below.

a) There will be need for an upgrade of the fluid return system on the vessel, in order to be able to handle contaminated returns from the well. The system will consist of high pressure (HP) piping from the fluid pumps to the well-center, and low pressure (LP) piping from the hydrocarbon vent-system and back to the vessels tanks. There will be needed an upgrade of the existing hydrocarbon vent-system, as it can handle a flow of 141 liters per minute, which is expected to be too low.
b) It is assumed that the existing 2'' Black Eagle hose may be used for taking returns from the well.
c) The SSD which will be acting as a secondary barrier during the operation will have to be operated from both the tower-cabin and from the tool-pushers office.

It is important to mention that the points listed are the main components needed and that minor additional equipment will be needed. [30]

5.3.3 Modification analysis

Based on the required modifications, time and cost estimates were done of the two alternatives. The analysis took basis in a 1-well campaign the first year, 4-well or a 10-well campaign the second year. The modifications and upgrades costs would therefore only be present for the first year. The modification cost estimates showed that alternative 2 would be 15% more expensive than alternative 1.

Thereafter, all the costs related to the operation were summarized. Rig rates, fueling, engineering, mobilization and other costs were estimated. It was assumed that it would take 12 days on average between finishing initial mobilization and the final demobilization. This time estimate was based on experience with operational time doing similar operations with a rig and an estimated mobilization time for the vessel. The total operational costs for both alternative 1 and 2, and for the first and the second-year campaigns were estimated. Due to confidentiality no fees will be disclosed. However, the estimates showed that the reduction in costs from the first year to the second year would be in the range of 40-50%, depending on the number of wells in the campaign the second year. This shows the importance of having multiple wells during campaigns. [30,31]

Another aspect which must be evaluated by Equinor is the experience that would be gained with completing this project. For development of rigless P&A methods it is important to have a long-term view on the projects, and costs will be reduced as experience will be gained. New experience on the subject may also lead to increased understanding of the operation which may result in discovery of new solutions. It was decided to move forward with alternative 1, which means that the rest of the thesis will take basis in that. However, most of the solutions developed will be compatible for a vessel that is capable of taking fluid returns.

5.4 Planned activity

For the project of tubing retrieval to be successful, it is favorable that the first operations are executed on wells that have certain specifications. However, it is important that the solutions are not solely dependent on specific well conditions. This means that the solutions discussed must be generalized with respect to relevant well characteristics that are likely to occur in wells in the NCS. Further, it is favorable that the candidate wells do not have any major integrity issues such as leaks or breached barriers that could lead to well control issues. Therefore, green wells be preferred when identifying potential first candidates.

5.4.1 Candidate well

This section will comprise a case evaluation for Kristin P-3H, a well that was identified as a possible candidate for the first rigless tubing retrieval campaign by Equinor. However, it is to be noted that the Kristin well was only evaluated as a potential candidate well and was later decided not to be part of the first rigless tubing retrieval campaign.

The Kristin field is known as a HPHT field, but due to pressure depletion it is now regarded as a HT well. P-3H is a well that has had leakages in the HXT in both the production master valve (PMV) and production wing valve (PWV), leaving the manifold valves as single barriers in the Xmas tree. The well has due to this been left in a shut-in state since October 2018. In order to revive the well the HXT will have to be replaced. As previously mentioned, the tubing hanger in HXTs are integrated in the tree structure, and consequently, tubing retrieval is necessary for replacing the HXT. An illustration of a comparable Xmas tree structure is depicted in figure 5-8. The high temperature conditions in the well has resulted in difficulties regarding the development of a cutting tool capable of sustaining the heats expected. Cutting tools for tubing will discussed in further detail in chapter 5.5.4. There are also concerns regarding the trapped volume that will occur between the temporary deep-set plugs. The temperature effects on the specific elements will have to be evaluated.

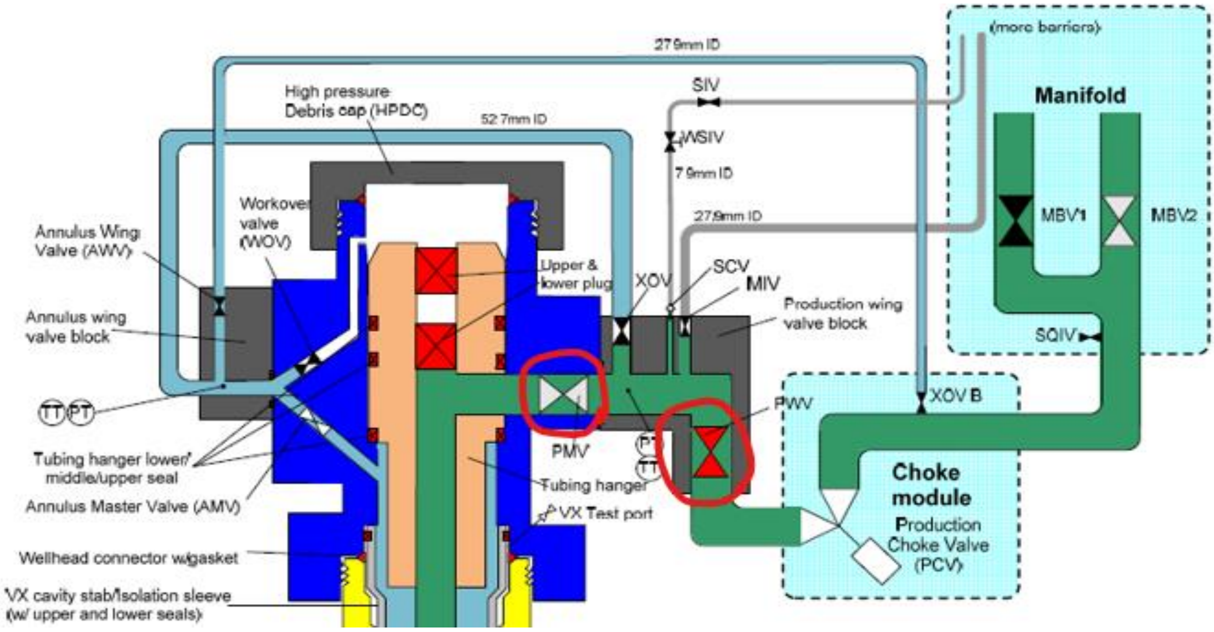

Figure 5-8: Drawing of the HXT on Kristin S-2H which is comparable to Kristin P-3H [32]

The shut-in wellhead pressure (SIWHP) in October 2018 was 211 bar. It is expected by the reservoir engineers that the reservoir pressure in the Garn and Ile formations could increase to a maximum of 460 bar, which will result in a maximum SIWHP of 307 bar based on a 0,036 bar/meter gradient. By including an estimated kill margin, the maximum pressure at the WH will be 342 bar. [32]

There are several factors that makes Kristin P-3H a good candidate well for a rigless tubing retrieval operation. Firstly, the operations planned for the well were set to be in the third or fourth quarter of 2020. This means that there was time for detailed planning of the operation as the planning started in late 2019. However, contracts will need to be agreed upon with contractors before any modifications on the vessel is made, which may result in delays.

Further, Kristin P-3H well also has a favorable well configuration as there are three options for setting deep barriers against the reservoir [32]:

1) In the 5 ½'' tubing, below the production packer, above the polished bore receptacle (PBR)
2) In the 5 ½'' tubing, below the polished bore receptacle (PBR)
3) In the 7'' liner, below the liner hanger

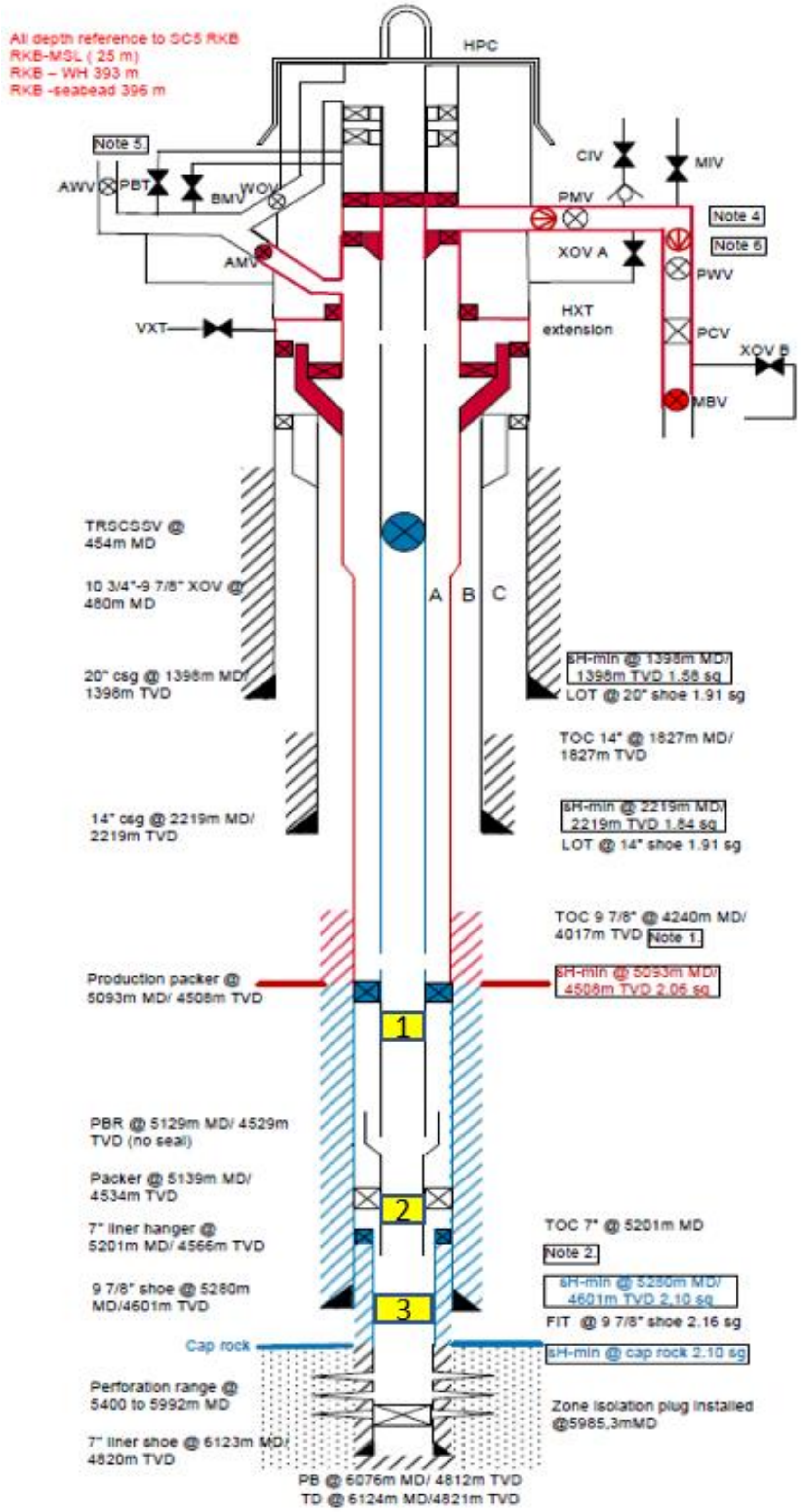

Figure 5-9: Well barrier schematics (WBS) with options for deep plug placement. [32]

Two barriers against the reservoir is required according to NORSOK D-010. [10] Having three barrier placement options left room for more alternatives of plug placement if any problems may be discovered. However, placing a barrier in the 7'' liner could induce some difficulties as an expandable plug would have to be used. It is also worth noting that there had not been identified any major restrictions in the well that could lead to problems when placing the temporary plugs.

Often, there are control lines facilitating equipment or gauges placed deep in wells. In Kristin P-3H there are no such gauges installed. This means that there are only two control lines that runs along the production tubing down to the downhole safety valve (DHSV). This may result in a simpler tubing retrieval operation as majority of the tubing will be pulled without control lines. A well without any deep-set gauges would also be favorable if it is intended to leave the tubing in the well when establishing a permanent barrier during a P&A operation. Control lines may induce an unwanted leak paths or micro-annuli in the cement as good cement bonding with control lines have proven to be difficult, although possible, to achieve. [22, 13]

As there is not a PBR above the production packer, less energy will be relieved if a shallow cut of the tubing is to be performed. This is because a PBR may induce unwanted kinetic energy to build up due to small movements. The fact that the production tubing size is also relatively small, 5 ½'', may also reduce the potential kinetic energy buildup that may be induced if a shallow tubing cut is performed.

Lastly, the weather during the winter months in the first and the final quarter of the year in Norway is known to be rough. By experience, waiting on weather (WOW) with the use of rigs during these months have been significant, and by having a vessel with a more effective heave compensating systems may be advantageous to reduce this down time. Generally, the heave compensating systems used on RLWI vessels can tolerate heave of 5 meters, while rig systems, in worst case, are limited to around 1.5 -2 meters of heave if a workover riser is connected to the well. However, during tubing retrieval operations rigs may tolerate heave up to 4m.

5.4.2 Summary

In conclusion Kristin P-3H is a well with a relatively simple configuration, where the operational risks are expected to be low as there are no known well integrity issues or wellbore component failures. However, the well is regarded as a high temperature (HT) well with temperatures up to 170 °C, which requires the downhole tools to be able to sustain such heats. This is regarded as a drawback.

Further, by installing two deep plugs to act as temporary primary and secondary barriers against the reservoir, the well integrity is maintained while the tubing is retrieved and the HXT is replaced. As the tubing retrieval operation on Kristin P-3H was set to be executed in the fourth quarter of the year, the heave compensation solution on the RLWI vessel may reduce down-time due to rough weather.

Due to delay in the tubing retrieval project, the Kristin P-3H well was later taken off the list for the first campaign. However, two Heidrun wells, in addition to a third well that is yet to be decided, that all have simple well configurations, are planned to be part of the first rigless tubing retrieval campaign scheduled to be executed in 2021.

5.5 Technical requirements

To extend the scope of the RLWI vessel Island Wellserver to include being able to retrieve production tubing, upgrades as previously discussed in section 4.1.1 will be needed. This section will elaborate on some of the necessary upgrades, in addition to technical requirements that relates to the operation. Four main subjects will be discussed:

1) The subsea shut-off device (SSD)
2) The through tubing logging method
3) The Subsea Jack system
4) The tubing handling system

5.5.1 Subsea shut-off device

The current well control package used for light well intervention on Island Wellserver is not rated for cutting tubing and may therefore not be used for the planned tubing retrieval operations. Therefore, a new well control package suitable for the purpose of tubing retrieval operations will have to be developed, namely the SSD. The device is to be developed by TIOS in close collaboration with its subcontractor Petro Support West (PSW) in Bergen, and TIOS' parent companies Island Offshore and TechnipFMC. PSW will be the owner of the SSD and the device will be delivered to TIOS through a rental agreement. The first tubing retrieval/slot recovery campaign is set to include 3 wells as previously discussed. However, the developments shall not be based solely on these well scenarios but instead be generalized in order to allow for possible future campaigns without the need for any major upgrades. Therefore, it is important that the SSD will be rated to cut high quality tubing with an outer diameter up to 7''.

The SSD that PSW initially proposed was based on a National Oilwell Varco SLX BOP consisting of a double block 18 ¾’’ CVX-W Shear Seal Ram (SSR) with an annular packer on top, and two side-bore inlets where one is located between the SSRs and the other located below. The system would be compact and light which was favorable as less rig space will be occupied and reduction in risk when handling the system on deck. However, complications with using this BOP occurred as the SSD would may be too compact. The considered double-ram BOP has limitations regarding the space-out, the distance between the rams, in addition to a limited selection of hydraulic operators that may be used for cutting. [33]

Island Wellserver utilizes a dynamic positioning (DP) system in order to maintain the position during operations. In situations where the weather gets too bad or potential DP system errors occurs, there is a risk of the vessel drifting away from the initial position. If the drift-off become too large during the operation, activation of the SSRs in the SSD may be the only option in order to not damage components in the subsea well system. It is therefore important to verify that the SSD will function during every possible scenario while retrieving the tubing. A situation that was discussed was whether the SSD could function during a situation where the tubing collars were centered between the two SSRs. The proposed ram blocks did not have the capability of cutting tubing collars. This would mean that if the tubing collars proved to be longer than the distance between the two SSRs, a scenario where both SSRs would be unable to cut may occur, which would be unacceptable.

A work sketch was made of the worst-case scenario. The situation is depicted in figure 5-11. The illustration was made with 7’’ tubing and VAM TOP ®HC collars with the length of 11,54’’, which are the longest collars present. The investigation showed that the collars had a clearance of 6mm to the center of both the top and bottom ram which is acceptable. However, there will be a delay between the closing of the upper and the lower SSR, which may result in the tubing moving after the first SSR have been activated. By this, a situation can occur where both the rams initiates cutting on the collar. Two possible solutions were discussed.

The CVX-V rams which were proposed to be used are not capable of shearing the most durable 7’’ production tubing or the tubing collars used. The 7’’ 32lb/ft SuperDuplex tubing is an example of tubing that is used that would not be suitable with the original cutting rams. As discussed earlier, it favorable if the developed systems are generalized in order to handle as many well scenarios as possible. Therefore, if the system shall be compliant for all types of 7’’ production tubing, installation of a different type of shear rams must be evaluated. A solution that have the shearing and sealing capability of the mentioned 7'' SuperDuplex production tubing is the Low Force Shear (LFS) ram from National Oilwell Varco. [34] This type of ram has both shearing and sealing capability, in addition to having a higher shearing capacity than the CVX-V rams. These rams utilize a puncture technique developed and discovered experimentally during a project trying to lower the shear force required to successfully shear steel tubulars. [34] If these rams were to be used, it would have to be investigated if modifications may be made on the door assemblies of the SSD, as the LFS-5 rams are designed to be compatible with NXT type BOPs and not SLX.

Figure 5-10: Low Force Shear ram by NOV. [35]

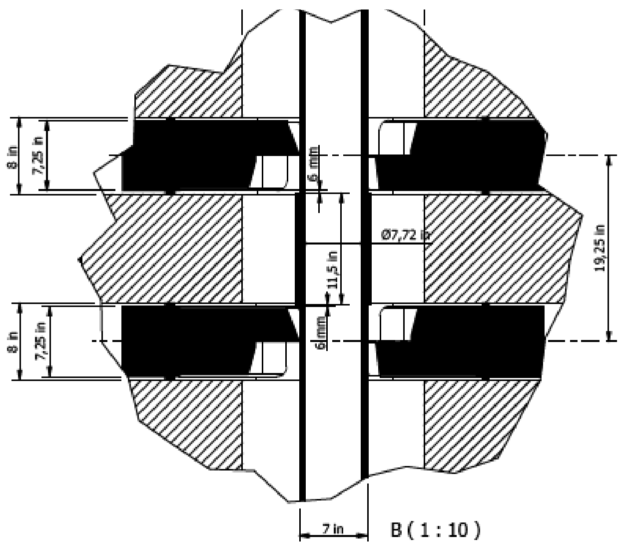

Figure 5-11: Cross-sectional figure of the SSRs with a 11,54'' collar centered between using the proposed NOV SLX SSD.

The other alternative was to increase the distance between the SSRs so that a collar would be able to fit between the two rams. This may be achieved by either installing two single-ram BOPs on top of each other or by using another double-ram BOP with longer space-out between the rams than the BOP previously discussed. With the use of two single-ram BOPS, the design would consist of a casing shear ram at the bottom with a blind shear ram installed on top. This would result in a larger and heavier SSD-assembly which is not preferred due to increased risk of HSE issues related to handling of heavy equipment and limitations with regards to deck space. In addition, a casing shear ram will not be able to cut during wireline operations, meaning that the ram or BOP would have to be switched during these logging runs which would be time consuming.

Instead, PSW identified a double-ram SSD from Hydril, which had a space-out between the rams of 76,9 cm compared to the 30 cm space-out on the NOV SSD. As shown on figure 5-11 above, the space-out of 76,9 cm would be enough to let both rams cut if a collar is positioned inside the BOP with a good margin as the collar lengths are estimated to be maximum 29,2 cm. However, there may be a scenario, ie. drift off, where a delay between the closing of the SSRs would allow the collar to move during activation of the SSD. This could therefore still lead to a situation where both SSRs are closing on the collar as discussed previously. To mitigate this, the delay between the closure of the SSRs must be considered carefully.

After moving forward with the Hydril SSD, the ram type would have to be changed as the ram inserts were not the same as on the NOV SSD. Tests and simulations would have to be performed in order to verify if the rams would be able to cut during the worst-case scenario, which was regarded as the scenario where the ram would have to cut in the tool joint and control lines. A relatively new type of rams was suggested; Wireline Blind Shear Rams (WBSR). The WBSR can cut through both wirelines and tubulars which is an important feature during tubing retrieval operations as both wirelines and tubing will pass through the SSD. [36]

To identify if these rams would have high enough cutting capacity a report was created by Baker Hughes. The report took basis in 15-18 type WBSR, but the shear calculator results would also be applicable for a casing shear, blind shear or wireline shear if any of these rams were decided to be used. Without disclosing any sensitive details of the report, it showed that the suggested WBSR would be able to tackle the worst-case scenario as required. It was therefore decided that these rams shall be used in both the upper and lower ram slot of the SSD. [36]

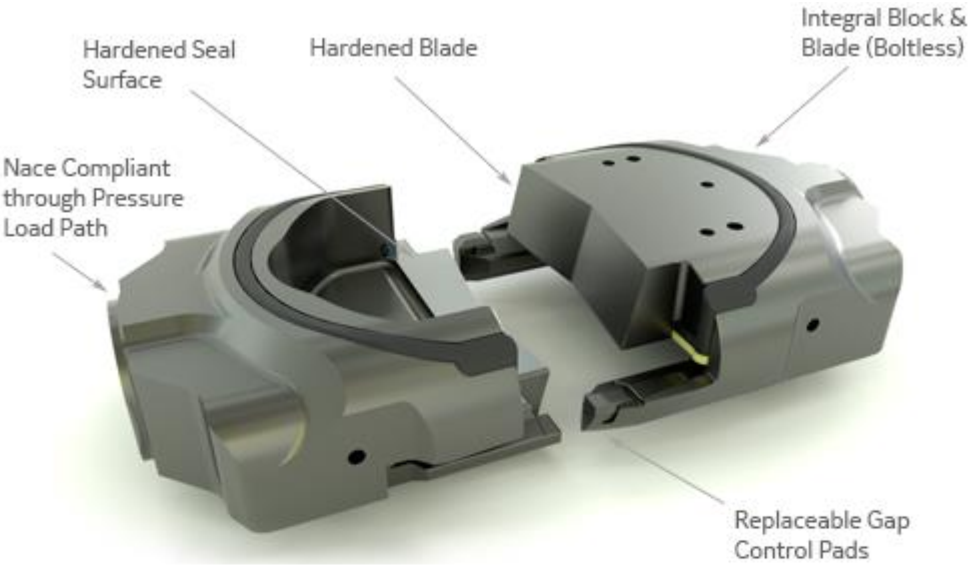

Figure 5-12: Wireline Blind Shear Ram from BHGE. [36]

5.5.1.1 Description of base concept of the double ram SSD

The main body of the double ram SSD proposed by PSW consist of the following elements starting from the top (Fig 5-12) [33]:

- Volume Control System
- Wellhead mandrel, H4/ BOP interface
- Annular Preventer (AP)
- Pressure transmitter
- 1 WBSR (ram)
- Pressure transmitter
- 2’’ inlet for circulation-hose
- 1 WBSR (ram)
- Pressure transmitter
- 2’’ inlet for circulation-hose
- H4 Wellhead Connector, suitable for landing the SSD on top of a XT or WH

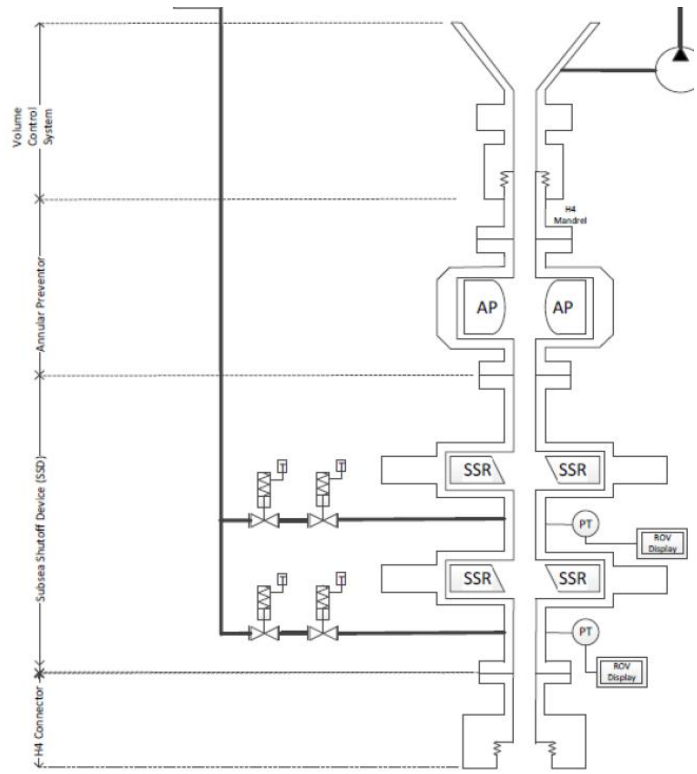

Figure 5-13: SSD configuration including volume control system [33]

The design of the SSD control system shall be based upon ISO 13628-6 Subsea Production Control Systems and will consist of a topside system installed on the vessel and a subsea system. In combination, the systems will control the SSD valves as well as provide monitoring of the subsea instrumentation and any ancillary equipment including the volume control system connected on top of the SSD. The connection between the topside and subsea systems will be via a single umbilical which supplies electrical power and communication signals. The umbilical has a hydraulically operated emergency disconnection system in addition to a built-in weak link in case of drift-off scenario. [33]

It is required that the new system is given a SIL rating of at least 1. The existing control system on Island Wellserver, which is planned to be re-used, does also have this rating. SIL (Safety Integrity Level) classifications are determined based on a probabilistic analysis made on control system hardware in order to identify the probability of system failure as discussed earlier. [33, 20]

It will be developed a ROV panel for operation of all the valves on the SSD, which means that all the functions of the SSD will be controllable from a remotely operated vessel (ROV) if connection is lost to the RLWI vessel. The control system will comprise a topside hydraulic power unit, an umbilical system, a safety system that includes required subsea controls and an emergency disconnect function for the umbilical and circulating hose.

In order to reduce the overall delivery time of the SSD, it has been decided to use as much of the existing well control package (WCP) control system as possible. This will however require an upgrade of the existing software to include an SSD-controller for controlling the SSD functions. By modifying the existing WCP control system, fewer new hardware components will be needed. Norwegian authority legislation will also require that most hardware components in the well control system must pass a 5-year reclassification test. [31]

Equinor requires that the safety system accumulators that shall be mounted on the SSD, must have a safety margin of 25 % of the minimum closing volume of the SSRs. The accumulators operating the systems not within the safety system, may be placed in a SSD controller unit externally from the main subsea unit. If the accumulators for some reason does not work, the SSRs should be able to be ROV operated as previously discussed. The accumulator design shall be done with respect to the API Spec 16D standard. [33]

A framework will have to be designed and constructed to provide a rigid protection with dimensions allowing the SSD to fit the subsea production templates. However, lifting will be done on the main components of the SSD and not through the protective frame. The frame will be corrosion protected with zinc anodes.

5.5.1.2 Shut down philosophy

If an emergency occurs where the vessel will be needed to disconnect from the well during operation, an emergency button activating the emergency quick disconnect (EQD) function is needed. The EQD function shall also be activated automatically upon loss of power and/or communication. If the operator for some reason does not manage to push the EQD button, the system shall activate the EQD automatically when the umbilical shear pins rupture leading to loss of power and/or communication. NORSOK D-001 requires dynamic positioned vessels to have EQD systems with the following three operations as minimum requirements[37]:

- Close and shear one shear ram
- Disconnect LMRP
- Close and seal one shear ram

As mentioned earlier the SSRs are required to have a separate accumulator bank allocated for the safety closing function, with a required pressure of the one-time closing pressure of each ram with a 25% safety margin. This pre-charge level shall always be monitored, and ROV readable gauges may be used for this purpose. The accumulator pressure shall also be displayed in the HMI and they shall be remotely operated due to requirements given in NORSOK standard d-001. [37] It is also of importance that the shut down system at minimum fulfils the requirements for a SIL 1 rating, however, SIL 2 will be favourable to achieve for as many steps as possible. [20]

After the SSD have been installed on top of the XMT, the SSD will be function tested in order to identify that all systems work as expected. During an EQD test the SSRs will be closed with the power supplied by the external accumulators. The same accumulators may also provide operating power to the gate valves outside the main bore. The main power supply to the accumulators operating the SSRs and valves will be the hydraulic power provided by the Hydraulic Fly Lead (HFL). The valves outside the main bore shall be fail-close, meaning that they will be closed if power supply is lost. This is also referenced in the NORSOK D-001 standard. [37]

The SSD will in addition have to be tested on deck prior to installation, if subjected to abnormal loads, after repairs or periodically according to NORSOK D-010. [10]

If the function test of the SSD fails, it will need to be retrieved and an investigation in order to identify the fault must be carried out. This may lead to severe downtime. Therefore constructing a SSD which has good reliability and maintainability is one of the most important functional requirements during BOP system design. [38]

It is important to note that NORSOK D-010 revision 4 is not updated on all solutions for rigless P&A but is expected to be updated with regards to the subject with a new revision planned to be released during 2020. [17]

5.5.1.3 Testing program

In order to identify that the SSD will work as intended with regards to the system, equipment and components, a testing program outlining the methods of testing is proposed. The testing will be split into three levels.

- Qualification testing
- Factory Acceptance Testing (FAT)
- System functions and integration testing

It is required that the system is qualified based on ISO 13628 and OLF070, in addition to internal testing requirements within Equinor, with the purpose of revealing any unidentified dangerous failures. [20]

Qualification Testing

All equipment that are not field proved, represent a new design or technology or equipment that shall be used in different conditions than already qualified for, will need to be identified and qualified for the intended use.

Factory Acceptance Testing

A Factory Acceptance Test (FAT) will be required in order to ensure that the components used in the SSD meet all the specifications. It was agreed upon that testing performed on component level by the manufacturer of the components would be accepted for the SSD system. The FAT shall be performed on all new deliverable assembly or components used that have not already been tested within Equinor's requirements. This means that existing equipment that is re-used will not have to tested. Some of the typical FAT verifications that are made are listed below:

- Dimension control
- Line verification
- Hydraulic capacity verifications
- Function testing
- Pressure testing, including gas tests if required
- Hydraulic flushing and cleanliness verifications
- Interface verifications
- Electric continuity and insulation verifications
- Weight verifications
- Load testing
- Interchangeability verifications

Once FAT is performed and verified on the required equipment the next step in the testing process may commence.

System Integrations and Stack-up testing (SIT/SUT)

As the control system software from several suppliers are used on Island Wellserver, it is important that the systems can work simultaneously as an integrated system to achieve the operational performance required. The purpose of the SIT and SUT is therefore to demonstrate that the interfaces are working as intended and verify the SSD systems operability. The SIT is planned to be performed in two separate set-up-s prior to main mobilization. One test shall be performed in the onshore site, and another test shall be performed onboard the vessel. The final test shall be the commissioning test onboard the vessel, which shall be done by use of the operations procedures, including between well tests, barrier testing and a full-scale emergency shut-down functions test. [39]

Onshore stack-up test

The onshore stack-up test (SUT) shall demonstrate that all interfaces are correct and functionality between the SSD and SSD controller works as intended. This includes the timing of activation of the SSR and volume control. The equipment is stacked up onshore and the equipment are tested and verified in accordance to required guidelines. The main equipment that will be required for a SUT are listed below:

- SSD including SSR accumulator banks
- H4 interface hub/connector
- SSD controller consisting of an umbilical termination head (UTH) base, Reservoir, Subsea Distribution Module (SDM) and Accumulators
- Hydraulic Flow Lead (HFL)
- Electric Fly Lead (EFL)
- Subsea Test Unit for a simulation of a topside test
- Test jumpers with pin connectors to hook-up to SSD controller

Onboard integration test

The main purpose of the onboard integration test is to verify the interfaces and functionality between the existing topside hardware, configuration of software, determine new configuration of existing subsea equipment, correct routing and verify the functionality of the shut-down sequences. For the test to be completed the following equipment are required:

- Integrated topside control system
- Existing umbilical and umbilical reel systems
- SSD controller
- Test Jumpers between umbilical and SSD controller umbilical termination head (UTH) base [40]
- Test multiple quick connector (MQC) plates for line verifications on SSD controller
- A sensor harness for transmission of signals

The commissioning testing onboard the vessel shall be within the normal scope of a test done prior to an operation offshore. During the testing process maintenance procedures and preoperations checks must also be used. The testing is finished when all the components, equipment and systems have been tested and verified in accordance to the required guidelines.

If any failures or degradations of safety integrated system components that requires any corrective actions or repairs occurs during operation, they shall be registered with a malfunction notification in the maintenance system. Depending on the classification of the failure the operations may need to be halted. The person responsible for the SIS offshore, is required to periodically go through these notifications until the fault is repaired by trained maintenance personnel. [20]

5.5.1.4 Corrosion protection

The materials selected for the SSD shall be suitable for the conditions expected during operation and service. To simplify the approach for material selection, the materials used for the primary components shall be in accordance with requirements of both ISO 13628-7 and ISO 13628-1. The ISO 13628-7 is a standard designed to describe the requirements and recommendations for the design, analysis, materials, fabrication, testing and operation of subsea completion/workover riser systems used on floating vessels. The ISO 13628-1 is a more generalized document that govern other parts of ISO 13628 going into detailed requirements of the subsystems in subsea production systems. [41,42]

To determine the materials pitting resistance a pitting resistance equivalent number (PREN) is used. The PREN for pitting in seawater is generally estimated to be around 32. Metallic materials exposed to seawater environment shall therefore have a PREN higher than 32. Further, materials used in seal areas in contact with well fluids are required to have a PREN of larger than 40. Typical materials used that have PREN higher than 40 are Inconel 625 and SuperDuplex steel. [43]

Galvanic cathodic protection

If any metallic materials used for the SSD are not resistant to seawater and the expected environment and conditions, ISO 13628-1 requires that galvanic cathodic protection shall be used. This is done by placing a sacrificial anode that is more reactive with seawater close to the structure that needs protection. The requirements for the materials to resists seawater and hydrogen induced stress cracking (HISC) by galvanic cathodic protection are given in ISO 13628-1. [44]

Protective coating

The ISO 13628-1 and NORSOK-M501 standards gives requirements based on the materials that is to be coated. The coating may have a function of protecting the material against corrosion in addition to coloring the equipment in a recognizable color. The color that shall be used on subsurface equipment is Yellow RAL 1004, while Orange RAL 2004 shall be used on the ROV grabber bars. [42,45]

5.5.1.5 Control cabinet

A control topside control cabinet will be installed on the vessel consisting of a PLC allowing for communication and input and output modules. A built-in 12inch screen will be used as a HMI. The HMI will be elaborated on in the next section. Communication with the subsea modules will be provided through the onboard TFMC Ethernet connection.

The control cabinet will be designed as a single control system with the possibility of connecting to both single and dual subsea units. Further, two fiber connections and two umbilical line connections for future use of the control cabinet without the TFMC control system will be installed. The communication protocol used for the communication between the SSD subsea sensors and HMI will be Modbus. [46]

The cabinet shall be installed in a protected environment. It shall in addition have a design allowing for easy handling and installation. The design shall also allocate free space in case of any future installations of additional equipment is to be made. [33]

5.5.1.6 Human machine interface (HMI)

As a part of the control system for the SSD it is required that user control and monitoring of the SSD sensor system is provided by a human machine interface (HMI) in the topside cabinet. The screen that is planned to be used will have reading of all sensors in the SSD subsea system and reset functions for the flow meter used to measure the consumed BOP fluid. The sensor readings will be displayed in the HMI with selectable engineering units. [33]

The HMI will be designed with a function to control the subsea electronic module (SEM) output signals to enable use of the SEM to control the SSD in installations without the TFMC control system. The SEM is the sensor that reads all the sensors used on the SSD. The TFMC system will read the sensor data, either directly from the subsea sensor SEM or from the topside PSW cabinet. It is required that any failure in the HMI system shall not affect the ability of the safety integrated system to perform its safety functions. [20]

5.5.1.7 Footprint

For the purpose of making a generalized tubing retrieval solution, it is important that the footprint of the SSD can fit the smallest templates on Equinor’s wells in the NCS. According to production tubing retrieval operations done by rigs, the maximum allowed footprint of a BOP is generally specified to be at 4800 x 4800mm in the 7 lowest meters of the template structure. This number includes a safety margin imposed by internal technical requirements of Equinor, that states that there shall be a clearance of 200mm to all interfaces during installation of a BOP. The components that are the most exposed of collision in case of too little space are neighbor trees and manifolds. However, there are templates of Equinor that will not fit a 4800 x 4800mm BOP.

As a request by Equinor, Technip FMC carried out a study of the interface check between Aker Spitsbergens BOP and the subsea equipment on wells in the Halten Nordland area. This area includes the smallest templates that are used by Equinor. The study concluded that the Spitsbergens BOP, with a footprint of 4500 x 3800mm, would collide with the templates and that the clearance in many cases would be less than the required 200mm. Based on the largest discrepancies where the BOP would collide with structures or equipment within the template, and a required safety factor 200mm clearance, the footprint of a BOP used for the most compact templates should be 4180 x 3528mm.

It is important that thorough investigation is carried out with regards to the size of the BOP, not only due to handling of large and heavy equipment onboard and limitations of deck space, but also due to being able to fit the equipment onto as many wells as possible without having to re-design. Although this may induce a more difficult and time-consuming design process, having a generalized solution will benefit the project long term as reconstruction of the BOP would be both costly and time consuming.

5.5.2 Through tubing noise log

After the well control system have been tested and verified according to the required standards, installation of the equipment on top of the HXT may commence. When the well control system, consisting of an SSD, a well control package (WCP), a lubricator section with a pressure control head (PCH) on top, have been installed, a logging drift run will be performed. This is done by use of a multi-finger caliper tool which maps the inside diameter of the production tubing, identifying any potential narrow passages or unidentified leakages in the tubing. With the information gathered during this run it is known what the maximum allowable tool diameter inside the tubing will be. If any holes in the tubing are observed, it would mean that the tubing integrity is weakened. A typical reason for this is acid corrosion. [47] Retrieval of a tubing which have been heavily corroded or weakened may require multiple fishing operations, resulting in a more complicated tubing retrieval operation. [13] Therefore, it is important that the production tubing condition is known prior to retrieval of the tubing.

In addition to the production tubing, the cement bonding to the production casing must be logged prior to retrieving the production tubing. Getting a log of the production casing cement is necessary, as information about the cement bonding will be important for barrier placement done in the following P&A operations. For P&A purposes, a through tubing logging method will therefore be used to verify the integrity of well barriers that are placed behind multiple casing strings. [13]

Over the years there have been performed extensive research in order to discover a logging method that is able to log through multiple steel tubulars. However, recent test projects done by Equinor give reason to believe that the use of spectral noise logging (SNL) technology may be a viable through tubing logging solution. [48] The general principle of this technology is to deploy a tool-string into the well, that can detect the noises created when fluids is flowing through tight spaces or crevasses. [49,50] That information may be used in order to identify the location of a potential leakage. This type of technology is provided by the technology company TGT and have, as mentioned, already been field tested in one of Equinor's wells during a test project done in order log the cement bonding quality where conventional tools did not suffice. This project will be elaborated on in section 5.5.2.3.

5.5.2.1 Technology

For the purpose of detecting leakages through noise logging, a tool provided by TGT called Chorus have been the most used within Equinor. Gullfaks is the field where Equinor have the most experience using this leak detection method, with the earliest test-projects starting in 2018. As the technology is relatively new, using the tool in field operations would contribute to making the logging method more accurate and reliable for the future. Therefore, development of new technology is not only dependent on the company providing the service, but also on the contractors that would have to take a risk using tools which they have less experience with.

Chorus, spectral noise logging tool, is a memory tool used to detect fluid movement that may occur behind multiple barriers with a good sensitivity. [51] The tool is designed and tested for investigation of the isolating status of various completion components such as tubing, gas lift mandrels, sliding sleeve doors, packers, casings and cement. By being a passive technology, chorus gathers information without any interaction from users while the tool is gathering information. The data gathered will however need to be interpreted by trained personnel once the tool is retrieved. The tool captures the noise generated by the movement of fluids through confined spaces or cracks. Depending on factors as the properties of the mediums involved and the flow-path size, noise in different frequency ranges are generated and picked up by the tool's receiver. By analyzing the data gathered, the source and route of a leakage can be determined. [51]

5.5.2.2 Physics of measurement

Chorus records frequencies and amplitudes of acoustic energy associated with fluid movement. The frequencies, recorded by a high-sensitivity hydrophone, are in the range of 8 to 58,500 Hz and are recorded in channels with widths of 115 Hz. Each channel has its own specific amplitude. The data recorded are stored in a memory section in the tool-string, meaning that the data will have to be interpreted after the tool have been retrieved to surface. One of the reasons for this is the limited bandwidth on the e-line cables. The tool-string configuration is shown in the picture below.

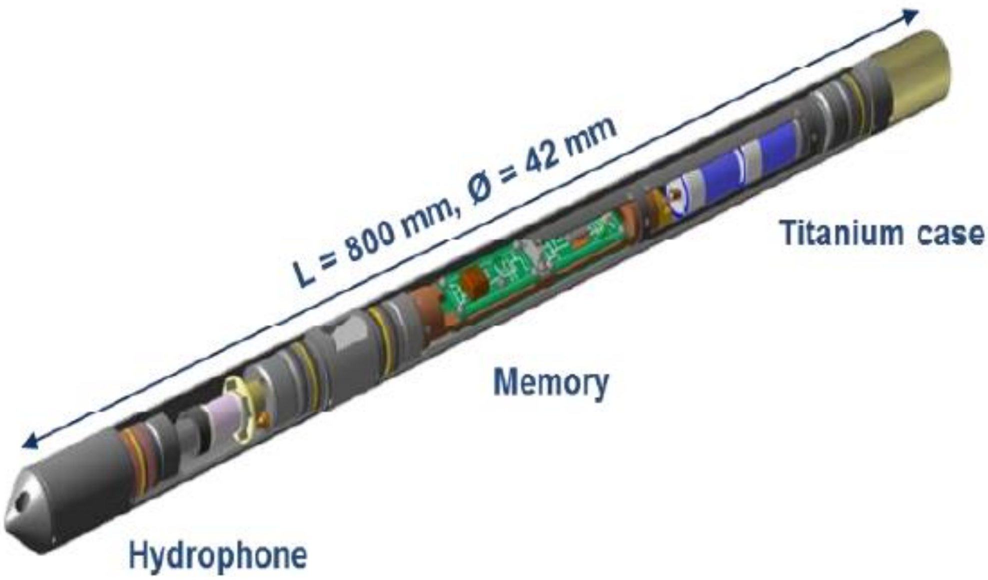

Figure 5-14: Chorus tool-string from TGT. [51]

The tools dynamic range, which is described as the ratio between the maximum and minimum detected value, is 90 dB. The data that the hydrophone records, are recorded with respect to the tool-depth, and are displayed on a data panel when the tool is retrieved. The hydrophone has a sampling rate of 1 second giving a vertical resolution of 0.8 meters. Depending on well configuration and mediums in place in the well, the hydrophone can typically detect noise that is generated 10-15 feet into the area of investigation, giving the tool a good horizontal resolution. One of the key features to getting an accurate noise log is to stack the data samples taken at the different logging stations. Usually, around 50 samples are stacked at every station. Doing this does also enable for extraction of unwanted noises using a correlative method. The tool can log both downwards and upwards. [50]

An analysis of the data received may provide an insight to both the origin and character of the fluid flow. The frequencies picked up are inversely proportional to the size or aperture of the flow path(s). Larger pores will generate low frequencies compared to the frequencies generated through flow through smaller pores. Therefore, an analysis of the received data enables to distinguish between different fluid sources and identifying the pathways of movement. Further, the amplitude of the noise is directly proportional to the product of flow rate and differential pressure through the pore or crack. Higher amplitudes will be observed in tight cracks with high differential pressures. Analysis of the geometry of the noise pattern, also contributes to revealing the source of noise or flow. Generally, noise created by flow in the reservoir is characterized by a wide frequency range streaks at discrete depth intervals. On the other hand, noise created by channeling in the borehole or cement typically have a much narrower frequency range and are tracked over longer intervals. In order to get even more accurate measurements, spectral noise logging have been combined with temperature logs. [50]

The battery capacity of the tool is 48 hours, meaning that battery capacity is generally not a limiting factor to the operational logging time. The tool is rated for 150 degree Celsius and 60 MPa, which in some cases may limit the tools capability of logging in HPHT wells. It is believed that higher pressure and temperature ratings will be introduced with newer models of the tool. The tool is also resistant to H_2S. A spectral noise logging panel with description of characteristics of different flows are depicted in the figure below. The picture shows how the filtered noise data is processed into multiple frequency channels with the use of a color spectrum for easier interpretation. [51]

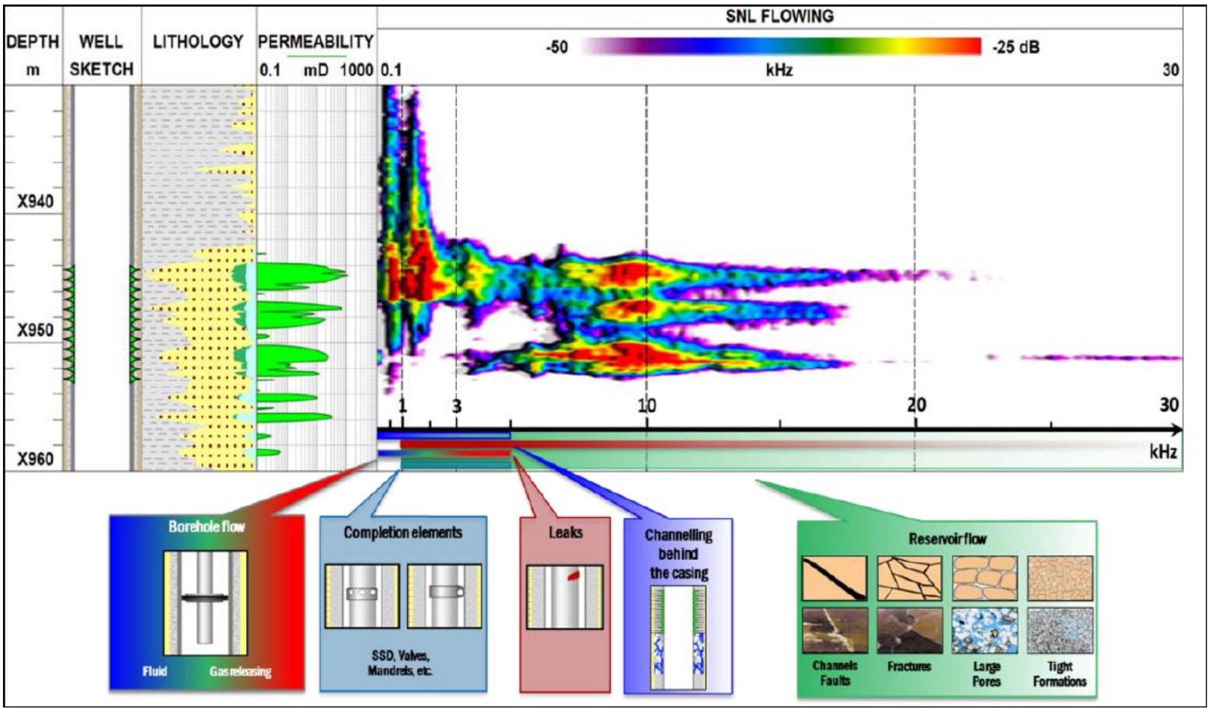

Figure 5-15: Spectral noise logging data panel, with descriptive characteristics illustrations. [51]

5.5.2.3 Field tests

In order to verify and prove that the technology works as intended numerous field tests have been carried out using the spectral noise logging technology. [50, 51] In early 2020 Equinor had a successful use of TGT's listening tool technology as the tool was used to gather information in a Kvitebjørn well. [48] The tool was deployed and taking measurements during an extended leak off test. The test was planned to be performed in order to prove the injectivity of the well and actual stress, confirming the pre-P&A strategy of the well. During the planning phase it was decided that the listening tool, that had previously been run in four Gullfaks wells and one Oseberg well, may provide with additional relevant information. [48]

The TGT chorus listening tool was run inside the drill pipe, while station logs were performed during injection and bleeding back. The test results confirmed that the injection was constrained to the Balder formation, which was essential knowledge for determining the pre-P&A concept. The tool did also provide with additional information regarding fracture growth, compared to the information gathered during standard extended leak-off tests (XLOT). [52]

The first step in the operation was to set a temporary Spartan plug below the formation of interest to build up pressure against. This plug had to be tested from below to verify that the plug was correctly installed. After the plug was verified, the Chorus listening tool was run on wireline without injecting into the well to establish a reference log. Thereafter, three cycles of XLOT were performed while the tool logged the noise both during injection and bleed-off. The tool logged at 30 seconds at each station. [52]

The result of the analysis of the gathered data provided valuable information in addition to the standard surface data. It both verified that injection was constrained to the Balder formation as mentioned while also proving that there was no leakage along the cemented casing below or above the Balder formation. [52]

The outcome of the test was that the listening tool worked as planned and relevant additional information about the wellbore was obtained. In addition, both TGT and Equinor gained more experience using a tool that is relatively new to the industry. Although the information did not change the existing pre-P&A plans, it contributed to verifying existing theories and at the same time eliminating others. [52]

5.5.3 Tubing cutting tools

As mentioned in chapter discussing the candidate well Kristin P-3H it was initially planned to be developed a WL-deployable cutting tool able to sustain high temperature (HT) conditions. Due to the Kristin well being removed from the first rigless tubing retrieval campaign, there was no longer need for such a cutting tool in order to complete this campaign as the Heidrun wells have moderate downhole temperatures. However, there will still be need for development of a HT WL cutting tool, as it is probable that rigless tubing retrieval will be performed on HT wells in the future.

There are several different methods and technologies used for cutting production tubing. When selecting what cutting method is most applicable for the chosen well, it is important that certain factors are considered. Firstly, the tools have differences regarding the amount of cutting debris created when performing the cut. Cutting debris left on top of a deep-set plug is both difficult and time consuming to remove. [13] In addition, there will be a higher risk of having a miss-run when trying to connect to a plug with debris on top of it.

Further, it must be evaluated if, and potentially where, the well shall be re-entered at a later stage in order to determine where to perform the cut. The cut point must therefore be evaluated based on the need for re-entry. In operations where the main purpose of retrieving the tubing is to replace or fix a HXT, it is often common to perform a tubing cut close to a coupling. As couplings have a larger outer diameter than the tubing itself, the couplings centralize the tubing in the wellbore, making for easier re-attachment of the new tubing. This may especially be helpful in wells that are significantly deviated. [53]

Identifying the compressional state of the tubing is also a factor to evaluate, as this could lead to the tubing only being partly cut in some situations. To verify if the cut has been successful, a circulation test with 700-1000 liters per minute should be performed after performing the cut. As discussed previously, the well temperature must also be assessed when selecting the method of cutting. Mechanical type cutters will often generate extensive amounts of internal heat due to the frictional forces, which in some cases may result in overheating the tool if the well temperature is close to the limit of the tool.

Lastly, the need for cutting precision must be evaluated. When cutting packers or annular safety valves, there is a risk of missing the cutting window. In these cases, it is preferred to utilize mechanical cutters combined with a no-go nipple system if possible, to increase the cutting precision. By combining a locating system within the cutting window with a precise cutting technique, the risk of performing the cut at the wrong location is reduced. [53]

Examples of relevant wireline deployable production tubing cutting methods, in addition to the benefits and drawbacks with these, will be discussed in the following sub-sections.

It is also a necessity to part the tubing once it is retrieved and arrives at rig floor. How this is planned to be done in addition to the tool that is planned to be used will be discussed in section 5.5.44.

5.5.3.1 Explosive cutters

A common method of cutting tubing with the use of wireline within Equinor have been to use explosive cutters. A typical bottom assembly while using an explosive cutter consist of: the loaded explosives at the bottom, a spring that centralizes the assembly, a detonator housing, a casing collar locator (CCL) and a cable head that acts as a weak link at the top in case the assembly get stuck. In deviated wells or in wells where the friction is high, a tractor may also be installed as a part of the BHA to aid reaching the desired cutting depth. The position of the tool is identified using the CCL-log which maps where the casing collars are located, in addition to the measured length of the wire deployed. The wire length will however need to be correlated with the CCL-log as the wire will be elongated. When the target depth is reached the explosive mechanism may be activated. An explosive tool utilizes explosive charge that when detonated fires a 360-degree radial explosive jet that severs the tubing. [53, 13]

Explosive cutting is regarded as a method with high reliability where the chance of getting the tool stuck is regarded as low compared to some other cutting techniques. In addition, when using explosive cutters, it is not a necessity to have overpull on the tubing string which is favorable when using a rigless unit due to the limited amount of equipment available. [13]

There are however some drawbacks using an explosive cutting technique. Since explosives are involved, there are certain operational risks related to utilizing such tools. The operational risks are regarded as comparable to the risks associated with using perforation guns. The containers where explosive tools are stored, should be marked with triangular marks that indicates that the container contains explosive material. According to NORSOK D-010 use of explosives are categorized as a critical operation. Further, to allow for use of explosive cutters, measures that reduces the risk of damaging components that are not supposed to be affected by the explosive cutting tool must be taken. Damage to a component in the well barrier envelope may lead to integrity issues. If utilizing an explosive cutting technique for cutting very corroded tubing, there is an increased possibility of causing damage to the surrounding casing and possibly rupture of the control lines. However, in the case of performing a deep cut for tubing retrieval purposes, rupturing the control lines will be a part of the cutting procedure. [10]

Another drawback with using explosive cutters is the amount of debris that is left behind prior to a cut. As discussed previously, debris left on top of a temporary retrievable tubing plug, may induce a more challenging plug retrieval operation. [53]

It must also be considered if the re-entry of the tubing is intended in future operations, as the use of explosives to cut the tubing may form a trumpet shaped cut. This, in addition to misalignment of the tubing, may make future re-entry more difficult.

Examples of wireline deployable explosive cutters that are used within Equinor are the Dynablade from Altus/Deepwell, PowerCutter from Schlumberger and the JRC Jet Cutter from Halliburton. The tools are based on the same principles but have some differences that must be considered when choosing the cutter. Some differences are in temperature and pressure rating, cutting capability and tool size. However, a comparison of the cutters will not be performed in this thesis. [53,54]

5.5.3.2 Downhole electric cutting tools

Another option to part the production tubing is to utilize electro-mechanical cutters. Due to the use of wireline, a mechanical cut must be powered by a motor rather than rotation of the sting. These cutters are conveyed by use of e-line cable that electrically powers the motor in the cutting device. The general principle behind these types of cutters is that the motor powers a rotating blade or blades, that creates a mechanical pipe cut through use of friction. A typical BHA setup using a mechanical cutter would be to have the cutting head at the bottom, followed by a housing containing essential electronics and a centralization system and lastly a CCL for localization purposes finished by a cable-head to act as a weak link.

The cut performed by these types of cutters are typically smoother and cleaner than the cuts performed with use of explosives which usually is regarded as quite rough. In addition, the debris left behind in the well after a mechanical cut is performed are minimal compared to the explosive tools. This reduces the chance of failing to attach to the temporary plug in the well, lowering the probability of miss-runs during plug retrieval operations. [53]

A mechanical cutting tool will also have a lower probability of damaging the outer casing and the control lines when performing the cut. If a successful cut is performed, the pipe may be retrieved efficiently. As mechanical cuts typically are clean machined cuts, re-entry of the well is regarded to be easier than with an explosive cut. These tools may also perform multiple cuts in a single run, reducing operational time significantly. There will not be any exposure of explosives nor chemicals to personnel with use of electro-mechanical cutting tool which also lowers the operational risks of the cutting operation. [53]

Even though most of the mechanical cutting tools indicates that they can cut tubing that is both in compression and tension, a tensioned tubing is preferred. If the tubing is too compressed, there is a risk of the blades getting stuck due to too high friction on the blade surfaces. This may in the worst-case scenario lead to the tool being stuck in the wellbore. The result of this may be additional operational time.

The design of design of electro-mechanical cutters may be described as more complex than the explosive cutters. Mechanical cutters consist of more moving parts and critical components that increases the risk of tool failure significantly.

The different types of wireline deployable electro-mechanical cutters that is most commonly used within Equinor are the DECT delivered by Altus, WellCutter from Welltec, MPC from Baker Hughes and the Single Blade cutter (WECT) from Halliburton. [55,56]

5.5.3.3 Plasma-based cutting

When cutting tubing on a wireline, the two methods previously discussed have been the most common. However, there are alternative methods of cutting that have been developed, which over the years have risen to be good competitors to the conventional cutting techniques. A cutting method that have been used to some extent within Equinor is plasma-based cutting. These tools cut the steel tubular by utilizing an accelerated plasma jet with a high temperature. [57] The plasma jet is activated when the internal pressure generated inside a radial cutting torch (RCT) exceeds the wellbore pressure. The pressure inside the chamber increases due the thermal expansion occurring when the primary fuel load is energized and turned into plasma. When the internal pressure in the RCT reaches a set value above the wellbore pressure it will expose the nozzle to the wellbore by displace a protective sleeve. [57]

A plasma cutting BHA would have the same configuration as the explosive cutting BHA described previously, but with different tools below the centralizer. Starting at the bottom of a plasma based cutting BHA there will be a pressure balance anchor that shall contain the pressure that is built up as the plasma is energized, followed by a radial cutting torch with nozzles, ending with a thermal generator and an isolation sub. [57]

The expected finish of the cut is typically somewhere between the finish of an explosive and a mechanically made cut. These types of tools do also have the benefit of being operable in wells with high temperatures.

It is important that the cutting tool chosen for specific wells is evaluated with respect to the mentioned factors in the introduction of chapter 5.5.3, in addition to previous experience with the cutter.

Figure 5-16: Example of a RCT BHA. [57]

5.5.3.4 Surface cutting

When the tubing arrives at surface it will have to be parted before it is handled by the pipe handling system. To part the tubing at the system a cutting device from NorOil Tools is planned to be used. This tool is a hydraulic cutting tool that breaks the tubing in about 10 to 15 seconds by utilizing horizontal sliding force against a cutting blade. [58] This technique may be comparable to the technique used in BOPs. The surface of the cut is rough compared to a machined finish, but it is not expected that the tubulars should be left heavily deformed. However, a possible area of concern by using this technique may be that the deformation of tubing may become large enough to make it difficult for the elevator to grip on to the remaining tubing after a cut. On the other hand, this situation has not been experienced during previous operations where this surface cutter has been used.

Equinor have already had positive experience with using NorOil Tools surface cutting tool as it has been used during a rig operation while retrieving a high grade 9⅝Q125 53,5 ppf casing on the Huldra field. The tool worked as intended, and it is therefore not to be expected that any problems with using the same solution for the tubing retrieval operations should occur. How the casings looked after the cuts had been made is depicted below. From the pictures as well as a video of the cutting procedure it seems like the casing break is quite brittle. [59,60]

Figure 5-17: Tubing cut with NorOilTools surface cutting tool. [60]

Before the cut is made the tubing is to be hung off in what will be referred to as a false rotary table. A false rotary table is generally a device used on drilling rigs for the purpose of being able to feed control system umbilical's through the drilling riser without interfering with the slips holding the tubular in place. [61] The false rotary table used on the tubing retrieval vessel will cover the moonpool and will be used to grip on to the tubing while performing the tubing cuts. It will also allow for umbilical's that is connected to subsurface equipment to pass through the moonpool while gripping the tubing.

Due to the design of the tool, the tubing will need to be cut approximately 30 cm above the tubing joint. It is not expected that this should impose any problems. When the tubing is safely cut the pipe handling system will transport the tubing to the destination of tubing storage. The tubing handling system will be discussed in further detail in chapter 5.5.6. When the cut tubing is removed, an elevator connected to the vessels heave compensating system will grip onto the tubing, pulling it up in order to prepare for a new cut. There are mainly two types of elevators that may be used for this; hydraulic or mechanic. The hydraulic elevator would grip on to the tubing by using friction, while the mechanical elevator would grip the tubing under the tubing joint securing a mechanical grip as the outer diameter of the joints are larger than the tubing diameter. Which type of elevator that is to be used is not yet determined and it may be likely that both elevators may be tested in order to identify the preferred type.

5.5.4 Volume control system

During the operations the mud level in the well may fluctuate, and in order to keep the mud level in the well stable there will be need for a volume control system (VOCS). The fluid in the wellbore will be used as a well barrier during the tubing retrieval operations, and it is therefore important that the fluid level is maintained at all times. The VOCS may also be used to detect any unexpected changes in the mud level, which in some cases may indicate a kick-scenario. [67] The following sub-sections will describe the main components of the VOCS.

5.5.4.1 Top-side system

The top-side system that will be required consists of a control container (CC) and an integrated pump and hose deployment system. The CC houses transformers, variable speed drives for the pump motors and the VOCS control system. The VOCS may be operated from the CC, however, the computer screens in the CC are normally mirrored to the drill floor main cabin where the VOCS operator will sit together with the TIOS drill floor supervisor and the winch operators.

The integrated pump and return hose deployment and recovery system mainly consists of a hose reel and an umbilical winch. The pump and return hose may be run parallel to other vessel operations as it is run off the side of the vessel. The maximum water depth that may be reached with the planned hose system is about 650m. [67] The CC in addition to the pump and hose system is depicted below.

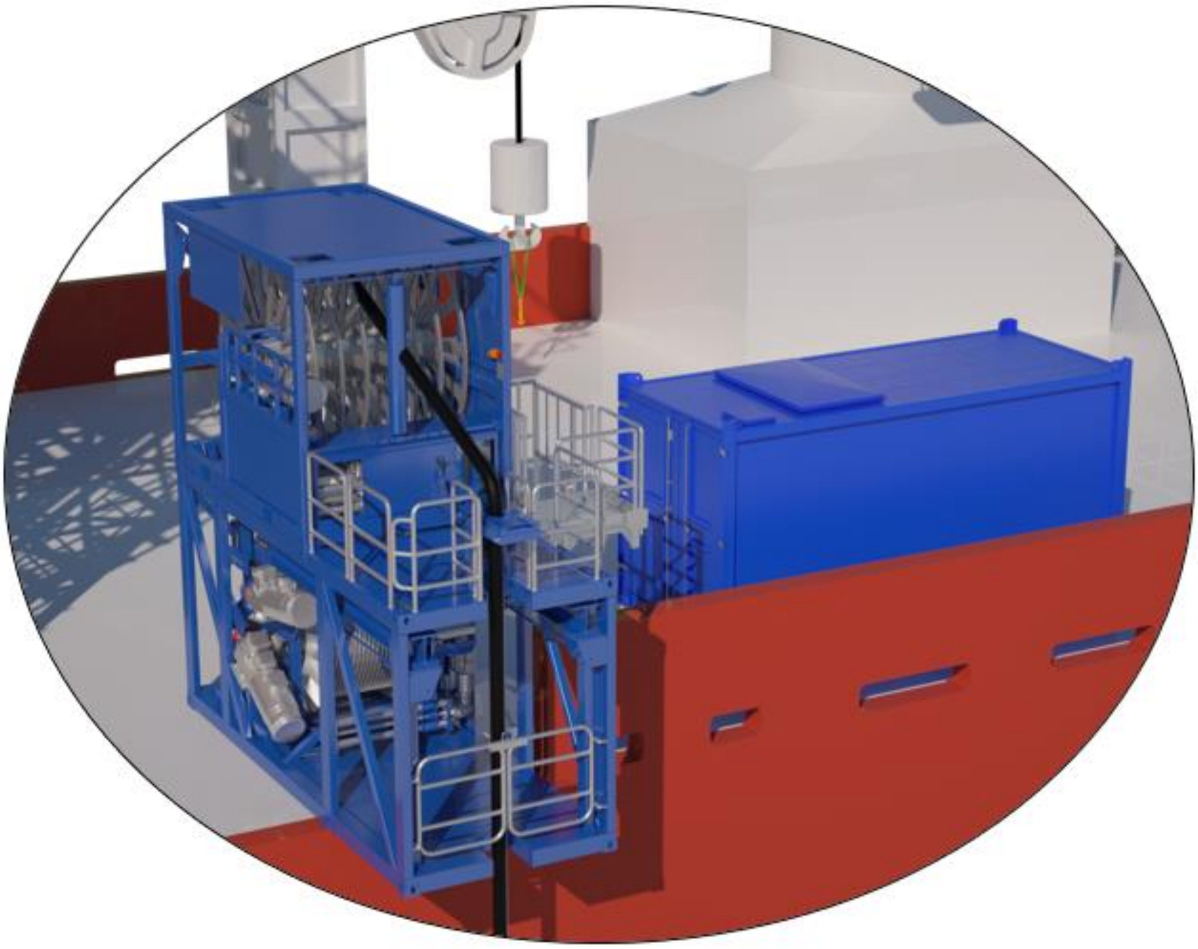

Figure 5-18: Pump and hose system to the left and control container to the right. [67]

5.5.4.2 Subsea pump module

On the seafloor there will be installed a subsea pump module (SPM) to supply pumping capacity. This module may be delivered as a one stage or a two-stage pump, dependant on the water depths and/or mud weights. For the operations that will be performed on the NCS it is believed that a one stage pump module will cover most wells. However, if necessary, a two-stage pump module with two pumps set in parallel mode may be installed. A two-stage pump module would result in 100% pump redundancy in case of a pump failure was to occur. This means that one pump will always be able to take over for the other if necessary.

The main function of the SPM will be to pump mud back to the vessel during circulation of wellbore fluids. It may also be used to u-tube mud back into the well as steel is pulled out of the wellbore and the fluid level changes. [67] The SPM is depicted in the figure below.

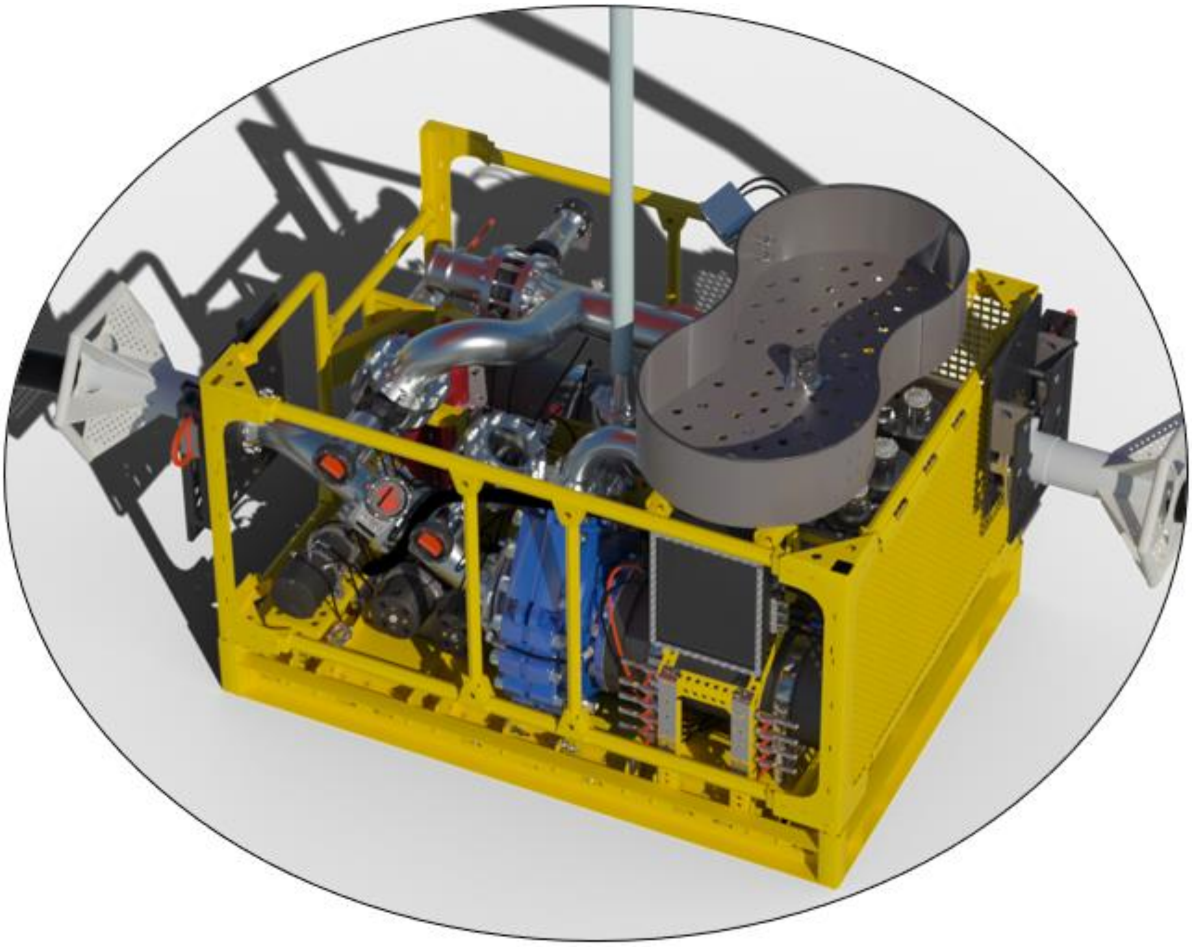

Figure 5-19: Subsea Pump Module. [67]

5.5.4.3 Wellhead injection module

On top of the subsea shut-off device it will be installed a wellhead injection module (WHIM) to enable for fluid to be pumped into the well. This device will be installed together with hydraulic cylinders of the subsea tubing hanger release jack. The subsea jack will be detailed further in section 5.5.5. Connecting the WHIM and SPM there will be a flexible hose that will in addition act as a trip tank during slot recovery.

On the WHIM there will be accurate differential pressure transmitters that will continuously measure the delta pressure between the outside and the inside of the WHIM. Any level changes in the WHIM will be detected by this system and be reported back to the control system. This way, the drilling mud that will act as a barrier during the tubing retrieval will always be under control and any changes will immediately be detected. As steel is pulled out of the well, the system will detect the volume changes and automatically backfill mud into the well to make sure that the well barrier is in place at all times during the operations. [67] The WHIM installed together with the subsea jack on top of the SSD is shown in the figure below. In addition, there is a depiction of the full system in figure 5-21.

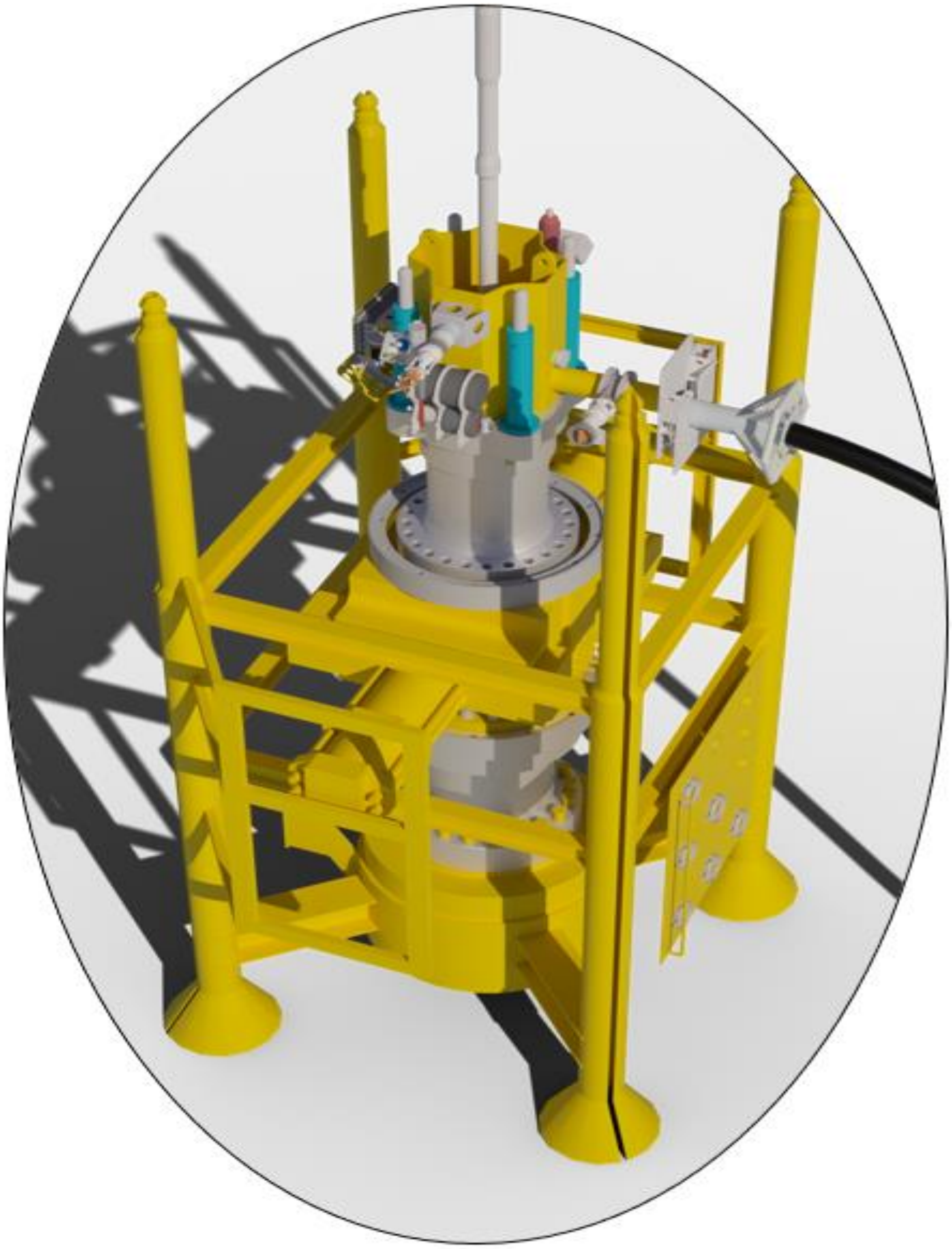

Figure 5-20: WHIM and subsea jack installed on to of SSD. [67]

Figure 5-21: Volume control system installed on an LWI vessel. [67]

5.5.5 Subsea tubing hanger release jack

The main operation of the slot recovery work planned to be done on Island Wellserver will be to retrieve and lay down the production or injection tubing from the well. To allow for tubing retrieval, the tubing hanger (TH) must be released. To release the TH from the tubing hanger seat, the seal-assembly must be released, and high pulling force must be applied.

One of the limitations by using a light intervention vessel for tubing retrieval is the pulling capacity of the vessels tower winch. Tubing hangers have often been exposed to high loads from the hanging tubing for many years, making the pulling force required to release it exceed the self-weight of the tubing hanger and its attached tubing. The tubing hanger condition may also be affected by the temperatures and pressures present, in addition corrosiveness of the fluids that the hanger is exposed to during its lifecycle. [62] It is also likely that a hanger will require a higher release force the longer it has been installed. Therefore, a subsea tubing hanger release jack is planned to be utilized in order to achieve the required pulling force. TIOS is to be responsible for the manufacturing of the device together with Malm Orstad. They will also be supported by Enhanced Drilling as they are responsible for the manufacturing of the volume control system that the jack will be connected to. The planned configuration of the system is depicted below.

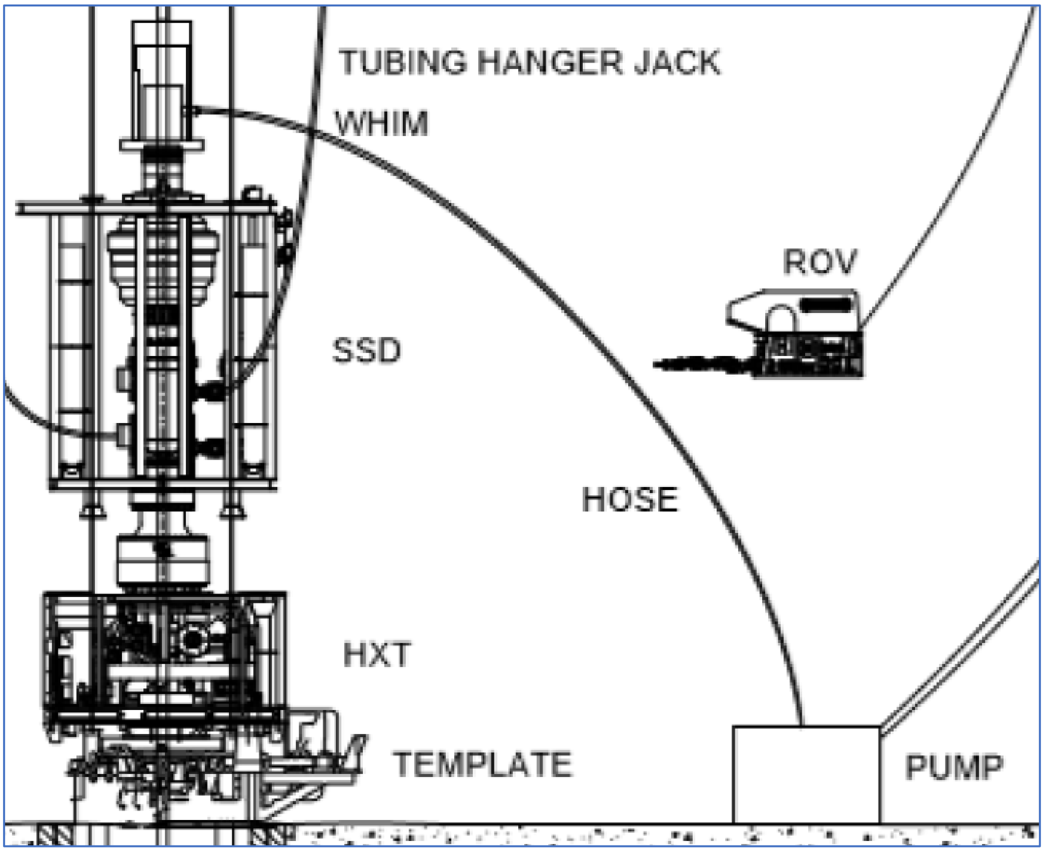

Figure 5-22: Overview of components installed on top of the wellhead. [63]

The subsea TH release jack will consist of the following components [64]:

- A top plate
- Hydraulic cylinders
- An ROV control panel
- Two short 5,5'' drill pipe sections with threads.
  - Top section will have box threads
  - Bottom second section will have pin threads
- A saver sub
- A spare hydraulic cylinder
- Equipment required for transportation and handling on deck
- A hydraulic system with the necessary hydraulic and electric lines

5.5.5.1 Installation

The subsea tubing hanger release jack is planned to be installed on top of the wellhead injection module (WHIM) as shown on picture 5-25. The jack will be lowered in two separate runs. As mentioned in section 5.5.4, the hydraulic cylinders of the tubing jack will be mounted to the WHIM on surface prior to deployment of the volume control system. When the WHIM, along with the mounted hydraulic cylinders, has been landed onto the SSD, and the coherent volume control devices are in place, the tubing hanger jack top-plate, consisting of the remaining components of the jack, may be deployed together with the tubing hanger release tool. Guideposts and guide wires will be utilized for easier positioning of the top plate during the landing sequence. An ROV will be used to monitor this sequence in addition to operate the ROV control panel. [63]

5.5.5.2 Tubing hanger mechanical release tool

When the tubing release jack have been landed in position, a tubing hanger mechanical release tool (THMRT) may be deployed by use of 5,5'' drill pipes. The tool is activated by applying downwards force after the tools lock ring has landed on top of the tubing hanger. The force will move the inner body of the tool downwards, opening a window that enables for compression of the THMRT lock ring. A mechanical spring force will try to push the lock ring outwards when it has retracted. When the ring is aligned with the locking profile in the tubing hanger the ring will snap out to engage. By applying pulling force after the lock ring have engaged the tubing hanger profile, the inner body of the tool prevents the lock ring from moving. The tubing hanger may then be released by applying pulling force. The retrieval tool mechanics are depicted in figure 5-23. [63]

When it is confirmed that the tubing hanger release tool has successfully engaged to the tubing hanger, the subsea tubing hanger release jack may be activated. Hydraulic force will be supplied by the hydraulic cylinders of the release jack, applying an upwards force against the top plate of the structure. The top plate is connected to two drill pipe sections with a connection in the middle, as shown in figure 5-24 below, which is connected to the THMRT. The pulling force will be increased stepwise. When the pulling force is large enough, weight readings from the tower winch will indicate that the tubing hanger is released from the HXT.

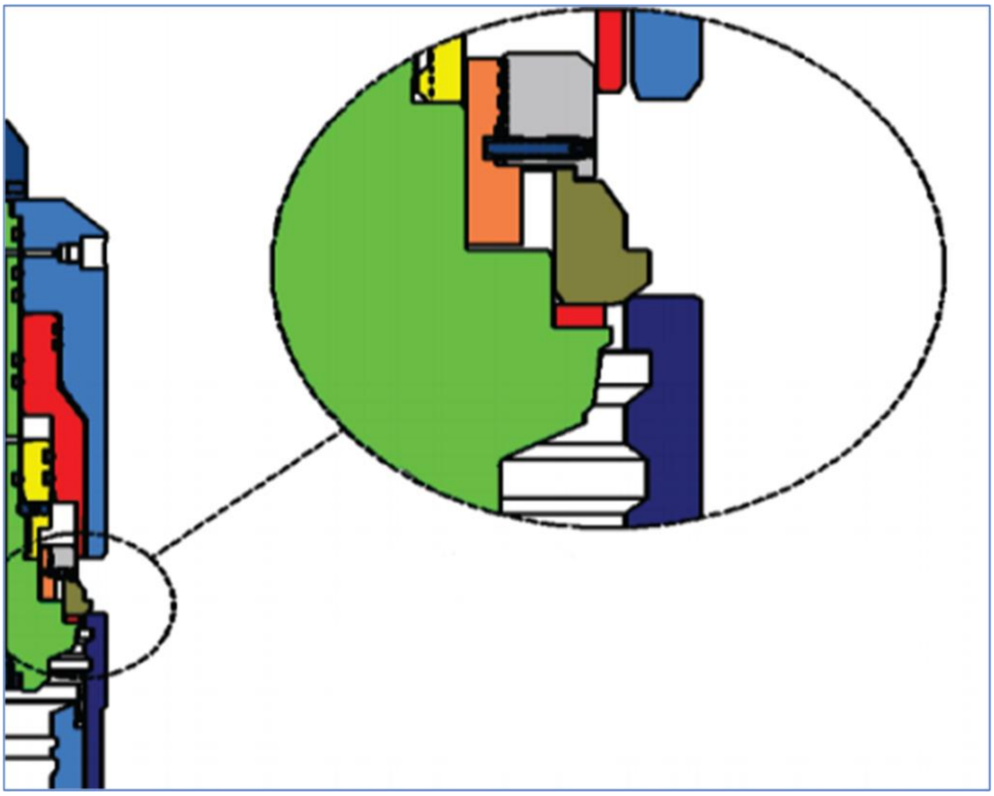

Figure 5-23: Tubing hanger and THMRT engagement mechanism. [63]

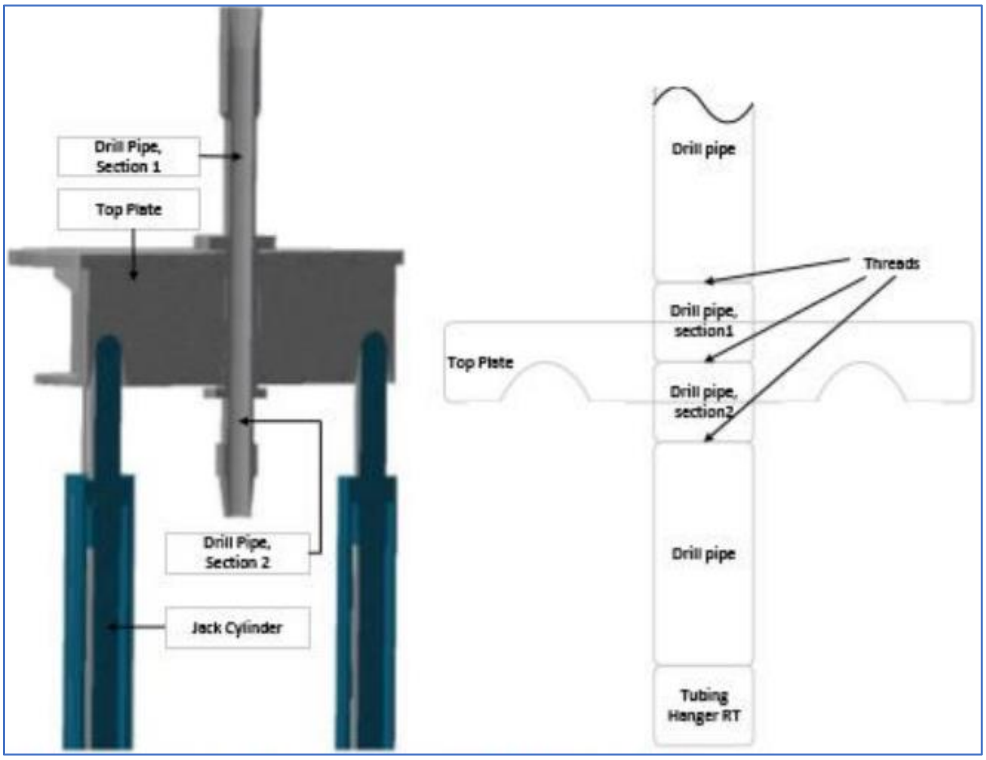

Figure 5-24: Cross-section of subsea tubing hanger release jack. [63]

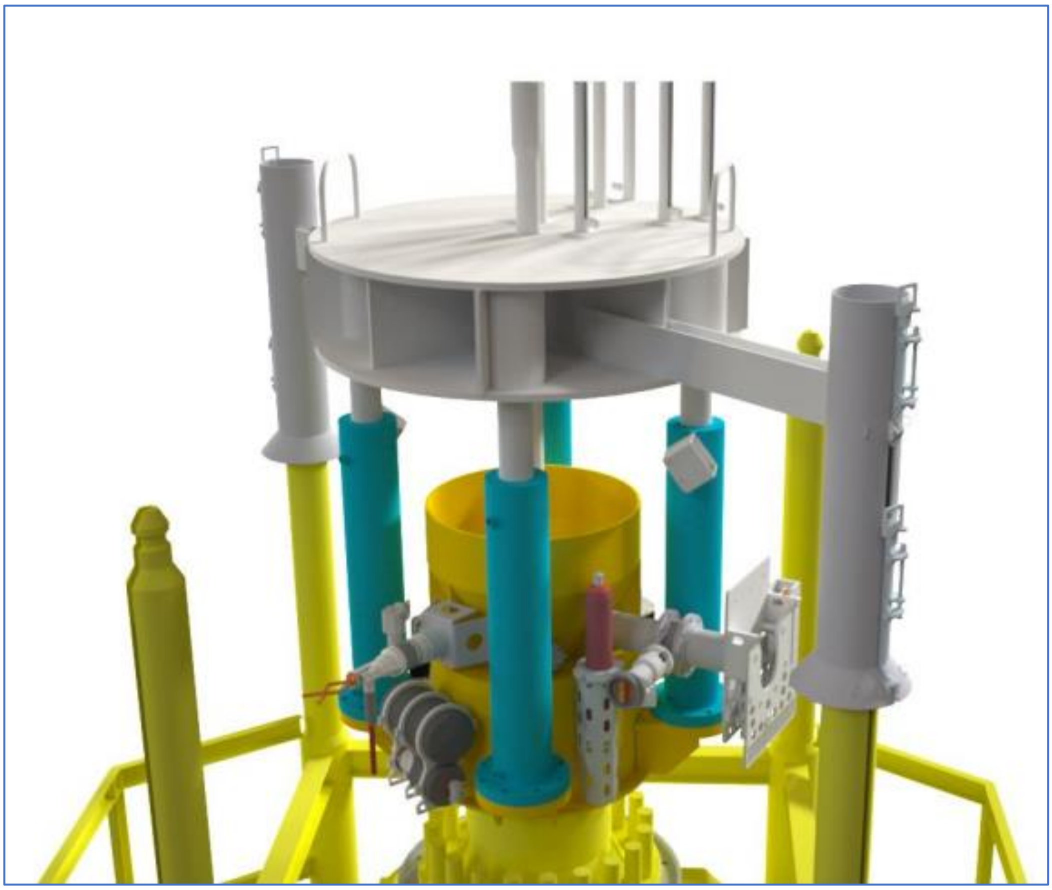

Figure 5-25:Subsea tubing hanger release jack installed on top of the WHIM. [63]

5.5.5.3 Technical requirements for the tubing hanger release jack

1. Previous gathered data regarding pull force required to release tubing have shown that the force required to pull loose tubing hangers does usually not exceed 300 tons. Therefore, the tubing hanger release jack will be designed withstand loads up to 350 tons in addition to a safety factor of 10%.

2. The jack will be designed to be used in water depths up to 500m as this will cover the relevant water depths for both the Norwegian and the UK sector.

3. The jack will be able to withstand temperatures between -18 and 40 degree Celsius.

4. The design life for the jack will be 20 years if maintenance procedures are followed.

5. Corrosion allowance for the equipment shall be done according to ISO 13628-7. Corrosion and corrosion protection were further described in chapter 5.5.1.4 – Corrosion protection. [41]

6. The hydraulic pressure input from the ROV is planned to be 210bar, however the hydraulic flow rate and the hydraulic tank volume used for the ROV is yet to be discussed. The ROV tank volume will however be kept below volumes in the hydraulic cylinders and lines.

The tubing hanger, along with the tubing, will be retrieved along with the top plate-structure of the tubing hanger release jack. The WHIM and the attached hydraulic cylinders will be mounted to the SSD for the remainder of the tubing retrieval operation. [63]

5.5.6 Pipe handling system

Since Island Wellserver was loaded with tool and equipment used for RLWI operations, there were no pipe handling system installed on the vessel. In addition, there were limited amount of deck space for storage of tubulars on the vessel, but as previously discussed in chapter 5.3 a mezzanine deck was planned to be built to encounter this challenge. However, there were no equipment previously installed on the vessel that allowed for save and efficient pipe handling to this deck. As a result of this, a new pipe handling system would need to be developed. This system is to be used both when deploying and retrieving drill pipe used for releasing the TH in addition to handling the retrieved tubing. The following sections will identify the main components of the pipe handling system, describe the operational sequence of the pipe handling system and some contingency plans if an undesired event would occur. The system shall comply with regulations and guidelines given by the OLF-081 guideline and the NORSOK d-

001 standard. [19, 37] The information given in this chapter is primarily based on a draft proposal given to Equinor by TIOS. [64]

5.5.6.1 Key components of pipe handling system

As there have not been performed tubing retrieval operations on Island Wellserver as of recent, the equipment in place does not cover the ability to retrieve pipes and handling them in a safe and efficient manner. Although, TIOS have had experience with using pipe handling equipment on previous comparable vessels. The pictures used in this section is from one of Islands other vessels where similar equipment have been installed. The systems described below are remotely operated in order to reduce the risk of pipe handling accidents occurring. [37]

1. Elevator

To be able to run tubing using the main tower winch, an elevator needs to be installed in the tower. This elevator will need to be able to turn from vertical position to a horizontal position as this will also be used when raising the pipes from a horizontal to vertical position and opposite. The main tower winch system will also need some modification in order to achieve the maximum pulling capacity. This is planned to be done by modifying the current turnover sheave solution with a lifting capacity of 100 tons, to a double fall sheave solution which will yield a predicted lifting capacity of 200 tons. The two scenarios were depicted in figure 5-4 and 5-7 in chapter 5.3.1. [64]

2. False rotary table

A false rotary table will be installed in the moonpool hatch in order to hang off the tubing or drill pipes during connections, disconnections or cutting of the tubulars. As described in section 5.5.3 this device will utilize slips that grips the tubing or drill pipes below the joints. It will be used both during deployment of drill pipes and during retrieval of drill pipes and tubing.

Figure 5-26: False rotary table with insert slips with colour coating as specified according to OLF 070 [64]

3. Iron rough neck

When running in and retrieving drill pipes an iron rough neck will be utilized in order to connect or detach the drill pipes. The rough neck will be used during spinning-in and torque make-up procedures of the drill pipes. This procedure will be described in chapter 5.5.6.2 - Planned operational sequences. The device will be relocated on the vessel by use of skids. The rough neck is depicted in figure 5-27 below. [64]

Figure 5-27: Iron rough neck installed on an Island Offshore vessel. [64]

4. Traveling trolley/cat-walk machine with a tail-in arm

In order to transport the pipes between the moonpool and pipe storage a traveling trolley will be utilized. This travelling trolley will be attached to the middle skids of the main deck as shown in the picture below. The traveling trolley mainly consist of a pipe gutter that houses the pipes during transportation and a shuttle block. The shuttle block is a structure that is able to run the full length of the pipe gutter in order to transport the pipe. [64]

Attached to the trolley will be a tail in arm, that will have the main purpose of guiding the pipe into the right position above the center of the drill pipe stick-up in addition to elevating the pipe. The relevant components of this arm is the monkey roller, which is used to guide and centralize the pipe, then a monkey trap, will secure the pipe in the monkey roller, and the telescopic arm structure will be able to rotate, extend and tilt the tail-in arm as desired. [64]

Figure 5-28: Travelling trolley with drill pipe in the gutter. The pipe storage rack in the background will be placed on the mezzanine as shown in figure 5-3. [64]

When picking up pipes, the shuttle will push the pipe forward until it sticks out of the travelling trolley. The tail-in arm will then manually elevate the pipe until it is in position so that the elevator may be attached to the pipe box end. The tail in arm is depicted in figure 5-29. [64]

Figure 5-29: Tail in arm used to guide the pipes during pipe retrieval and deployment. [64]

5. Pipe handler crane with lifting beam with grabbers

To move the pipes between the pipe storage mezzanine deck and the travelling trolley there will be need for a pipe handling crane with a lifting arrangement connected to it. During pipe handling operations it is planned to convert the port side crane into a pipe handling crane. The lifting arrangement will be two grabbers placed on the opposite ends of a lifting beam. The grabbers will be lowered down to the pipes and activated in order to grab around the pipe bodies. During rough weather conditions where there may be risk of pipe rotation during the lift, a tag line may be required at each end of the drill pipe so that the ends can be held back. [64]

Figure 5-30: Lifting beam grabbing pipes from pipe storage rack. [64]

6. Hydraulic Power Unit

The new and existing equipment installed will need to be supplied with hydraulic fluid. Therefore, a hydraulic power unit will be mobilized in order to serve the hydraulic fluid users.

5.5.6.2 Pipe handling sequences

In this section the different relevant operational sequences for the pipe handling system during tubing retrieval operation will be detailed. During the operations the Module Handling Light Tower (MHT) operator shall assume responsibility for controlling the pipe handling operations under the supervision of the Operations Supervisor from TIOS in addition to the Captain. There will also be personnel operating the pipe handling crane, the rough neck and the main winch elevator. All operators will be equipped with PTT communication radios as there will be communication between the operators at all times. The TIOS Operations Supervisor shall prior to any operations assess the working conditions and based on that, in some cases, conduct a Safe Job Analysis (SJA) with the involved deck personnel to identify and new potential hazards. Prior to operations there shall also be completed a toolbox-talk in order to inform all concerned parties of any potential changes to the scope of work. All involved personnel will be instructed to pause the ongoing operations if they are not comfortable with the safety in place during the work. [64]

5.5.6.2.1 Deploying drill pipe

The pipe handling systems will first be utilized when running drill pipes into the well for release of TH. The first step in this process is to move drill pipe from the storage rack to the travelling trolley. The procedure is done as follows [64]:

Transportation of pipes from storage rack to pipe handling system

1. Skid pipe handling system to the delivery position for pipe handling with the front pallet resting on the moonpool door.
2. Position the travelling trolley in line with the pin end of the drill pipes stored in the pipe rack. This is done so that the pipes may be dropped directly into the trolley without the need for further adjustment.
3. Remove the thread protectors from drill pipe that is to be grabbed.
4. Dope the pin end threads of the drill pipe.
5. Open grabbers on the lifting beam and position the grabbers just above the tubular to be lifted like shown on the picture 5-30 above.
6. Lower the grabber until both grabbers have engaged the tubing and close the grabbers around the tubular body.
7. At this stage, if necessary, a tag line may be attached to the box end of the pipe in order to avoid uncontrolled rotation during rough weather conditions.
8. Lift the tubulars up until it is visible above the tubular cassettes.
9. Retract the pipe handling crane while keeping the tubular aligned with the pipe handling system.
10. Ensure that the pipe is stabilized and lower it until it lands in the pipe handling system gutter.
11. Set down the weight and open the grabbers to release the tubular. Prepare for picking up next pipe.

Picking up pipes from horizontal to vertical position

1. Drive the drill pipe forward in the pipe handling trolley by use of the shuttle until the pipe box end is approximately one meter from the moonpool center.
2. Engage the tail-in arm with the pipe and raise the pipe box end until it is raised higher than the stick-up of the drill pipe joint hung off in the slips.

3. Drive the drill pipe forward until it is above the pipe stick-up to prepare for connecting the elevator.
4. Manually tilt drill pipe elevator from vertical to horizontal position.
5. Lower the elevator and manually latch the elevator on drill pipe. (For this example, a mechanical elevator is used that grabs around the pipe below the pipe joint.)
6. Verify that the elevator is properly locked and attached before lifting the pipe.
7. Set the travelling trolley in free-wheel position.
8. Hoist the drill pipe into the tower. The drill pipe elevator will have a mechanism that will automatically rotate the elevator from horizontal to vertical position as it lifted.
9. Close tail-in arm around the drill pipe pin end before the pin end leaves the travelling trolley.
10. Position the pipe pin end above the center of the drill pipe stick-up box end by use of the tail-in arm.
11. Lower the elevator until the pin end rests in box end of previously run drill pipe.
12. Release tail in arm and retract it from the drill pipe.
13. Drive travelling trolley aft in order to prepare lifting the next joint into the pipe handling system.

5.5.6.2.2 Spinning-in and torque make-up of drill pipe

At this stage the drill pipe is attached to the elevator with the pin end resting into the box end of the pipe stick-up. By use of an iron roughneck, the procedure for connecting the drill pipes together are as follows [64]:

1. Drive the iron roughneck to the drill pipe stick-up in the moonpool center.
2. Adjust the height on the iron roughneck such that the make/ break assembly is aligned with the tool joints.
3. Attach spinner tong to the hanging drill pipe, spin in the pipe and release the spinner-tong.
4. Attach the make/break assembly to the tool joints.
5. Make up drill pipe connection according to the torque given in the drill pipe specifications.
6. Check the first few joints in order to assess if too much dope have been used on the threads. Wipe off dope-excess and adjust the amount applied while the pipes are stored in the pipe rack. (The weight of the dope is noted down before and after all pipes have been run to identify total dope usage)

5.5.6.2.3 Running pipe through moonpool

When the drill pipes are connected the pipes may be lowered through the moonpool. The procedure is as follows [64]:

1. Pick up pipe weight with elevators and open the slips in the false rotary table. The full weight of the sting will be carried by the main tower winch.
2. Lower the drill pipe string until the end of the joint is positioned above pipe slips such that a new make-up may be performed.
3. Establish communication with bridge and identify if the drill string deflection is acceptable with respect to the engineering analysis.
4. Add the drill pipe joint details to the deployed pipe tally log.
5. Open drill pipe elevator and prepare for lifting in the next drill pipe.
6. Continue running drill pipe until required depth is reached.

5.5.6.2.4 Retrieving drill pipe or tubing

Retrieving the drill pipe or the tubing is done in the exact reverse order as the procedures described in the sections above, running drill pipes into the sea [64]:

1. Ensure that the false rotary table is installed properly with all covers closed and safe working environment on the moonpool area.
2. Pick up the end of uppermost tubular joint through the slips with the elevator such that the connection is positioned at the correct height for breaking the tubular. The iron roughneck will be used to part drill pipes while the surface cutter from NorOil tools described in chapter 5.5.3.4 will be used to break the tubing. [58]
3. Set the slips when the tubular is positioned correctly according to previous step. Slack off the elevators in order to transfer the drill string weight to the floor and attach the slips tightly to the pipe body. During the first connection only, observe that the slips are holding the pipe in place after slacking off the elevator. If no movement is observed continue to next step. The scenario of movement is observed are described in at the end of this section.
4. Ensure that all LP and HP pumps are shut down by opening the bleed valves on the HP pumps to ensure that the pressure in the HP system is fully vented to the atmosphere.
5. Check that the drill sting internal pressure has been vented to atmosphere.
6. Break the tubing with the surface cutter or disconnect the drill pipes with the iron roughneck and lift up the cut tubular by using the elevator.

7. Transfer the tubular to the pipe handling machine and place it in pipe storage rack on the mezzanine deck. Repeat the process until all tubing is retrieved.

If tubular begins to descend when the slips are engaged, the following procedure shall be followed:

1. Maintain the position of the elevator or pick up the pipe very slowly.
2. When the joint is one meter above the slips the slips may be opened. The condition of the slip dies shall be identified as these are the most common source of slipping pipe. Replace if necessary.
3. Position the tubular with the correct stick-up length above the false rotary table and engage the slips. Slack of the elevators to verify that the slip is holding the pipe in place. If the tubular is still slipping, repeat the process until the source of slippage is identified.

Having a detailed procedure to follow during operations with heavy lifting is an important part of reducing the risks of injuries. In addition, there will, as mentioned, be communications between all the workers at all times, which will also contribute to increasing overall safety of the operation. Equinor's policy for work deck is that all workers at any time are advised and required to give notice if they do not feel safe about an ongoing operation or if unnecessary risks are taken. The number one priority will be safety. [19]

5.6 Planned operational sequence

In this chapter the planned operational sequence for the rigless tubing retrieval will be discussed. Description of the main methodology of the different steps of the operation will be given. The operational sequence that will be the described is an example of a planned sequence that could be used for a typical candidate well described in chapter 5.4. However, it must be noted that the operational sequence may vary with respect to factors such as the type of XMT that is in place in addition to the desired outcome of the tubing retrieval. The general principles of how the operations are performed will still be the same, and well control must always be considered as the highest priority. The following operational sequence is an example of the sequence that may be utilized when performing tubing retrieval on a well with a HXT.

1. Removal of debris cap

In wells with subsea XMT's it is important to keep the wellbore isolated from the surrounding environment. This is done in order to prevent fish or suspended particles in the seawater to enter through the top of the XMT in addition to preventing degradation or corrosion of the H4 connector. For this a debris cap is always installed on top of the XMT before leaving a well. Therefore, the first step of an operation is to remove the debris cap. This will be done by the vessels slickline as these caps are regarded as relatively light.

An ROV will be used to connect the slickline to the top of the debris cap but will usually not monitor the debris cap while it is being retrieved. However, the ROV will be used to inspect and wash the H4 connector sub in addition to the multiple quick connector (MQC) as scale to various degrees may be present. Depending on how long it has been since the last workover on the well in addition to the subsea environment on the well this washing procedure may typically take between 1 to 15 hours. The washing technique that is most commonly utilized is the high pressure washing, brushing and acid treatment.

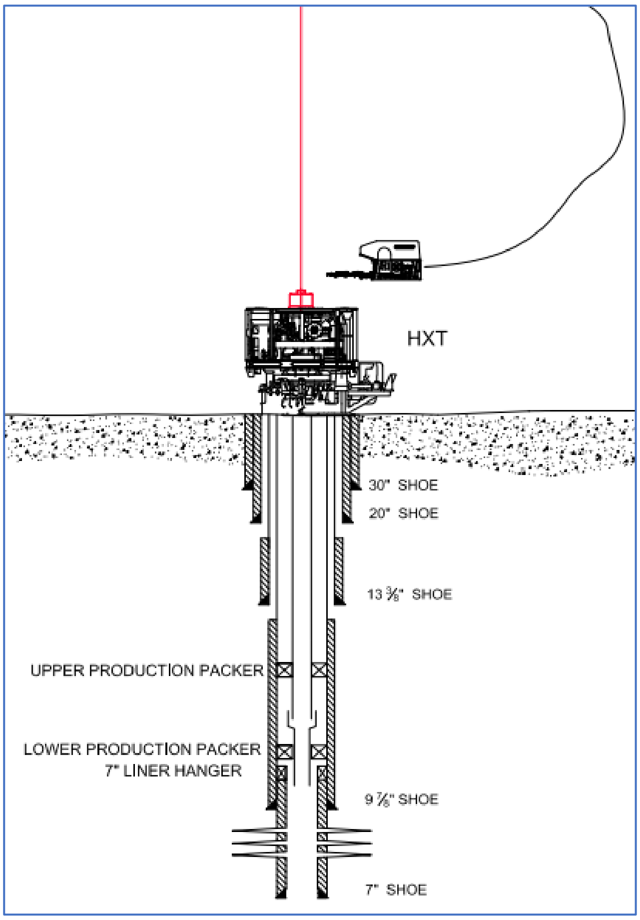

Figure 5-31: Removal of debris cap. [65]

2. Deployment of SSD

When the connectors have thoroughly washed the installation of the well control equipment may commence. There is an option to run the subsea shut-off device at this stage or wait until the wireline operations have been executed and wireline control equipment have been retrieved (step 10). However, for this example, the SSD will run prior to deployment of the wireline control equipment and will act as a foundation for the WCP and Lubricator Section (LS).

Given that the SSD have been tested and verified, it is deployed with use of the main tower winch through the moonpool. The vessels heave compensating system will be activated when the SSD have reached a certain depth. This system compensates for the vertical movement that may occur due do the wave oscillations. The heave compensating system is especially important to utilize when installing heavy equipment as a possible impact against the subsea equipment could lead to severe damage. It is preferred to perform this operation in nice weather conditions as transportation of heavy objects on deck can be highly dangerous.

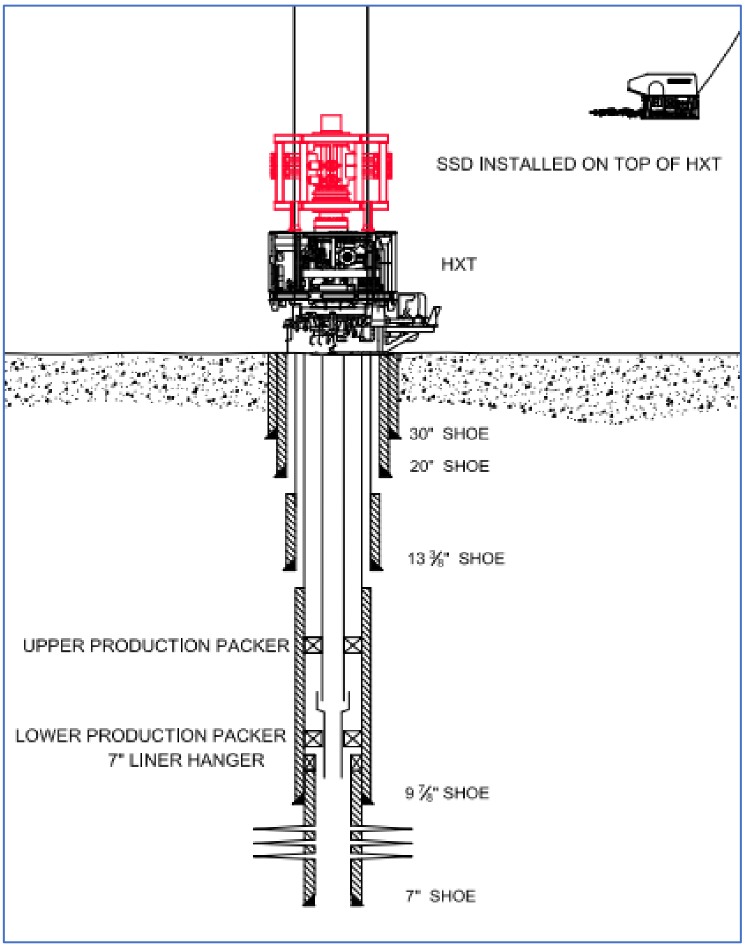

Figure 5-32: Installation of SSD on top of HXT. [65]

In order to control the direction of the SSD during deployment guide wires is to be used. These guide wires run from the vessel, through the SSD and down to the guideposts on the XMT. An ROV will be used to monitor the SSD while it is being lowered down onto the XMT.

3. Deployment of WCP and LS

Before the production tubing may be retrieved, the well must be temporarily isolated from the reservoir. This is usually done by use of a wireline deployable and retrievable temporary plug, which means that wireline well control equipment must be installed. The WCP is lowered onto the SSD or the XMT, depending on if the SSD is planned to be installed before or after the wireline operations will be performed.

Thereafter, the lubricator section is landed onto the WCP and the wireline well control system is finalized by installation of a pressure control head (PCH), also called grease injection head. The grease injection head is run after the tool has been lowered through the moonpool and has the main purpose of creating a seal around the cable used. The equipment installed in this step is run with the use of guidewires while being monitored by the ROV during transportation.

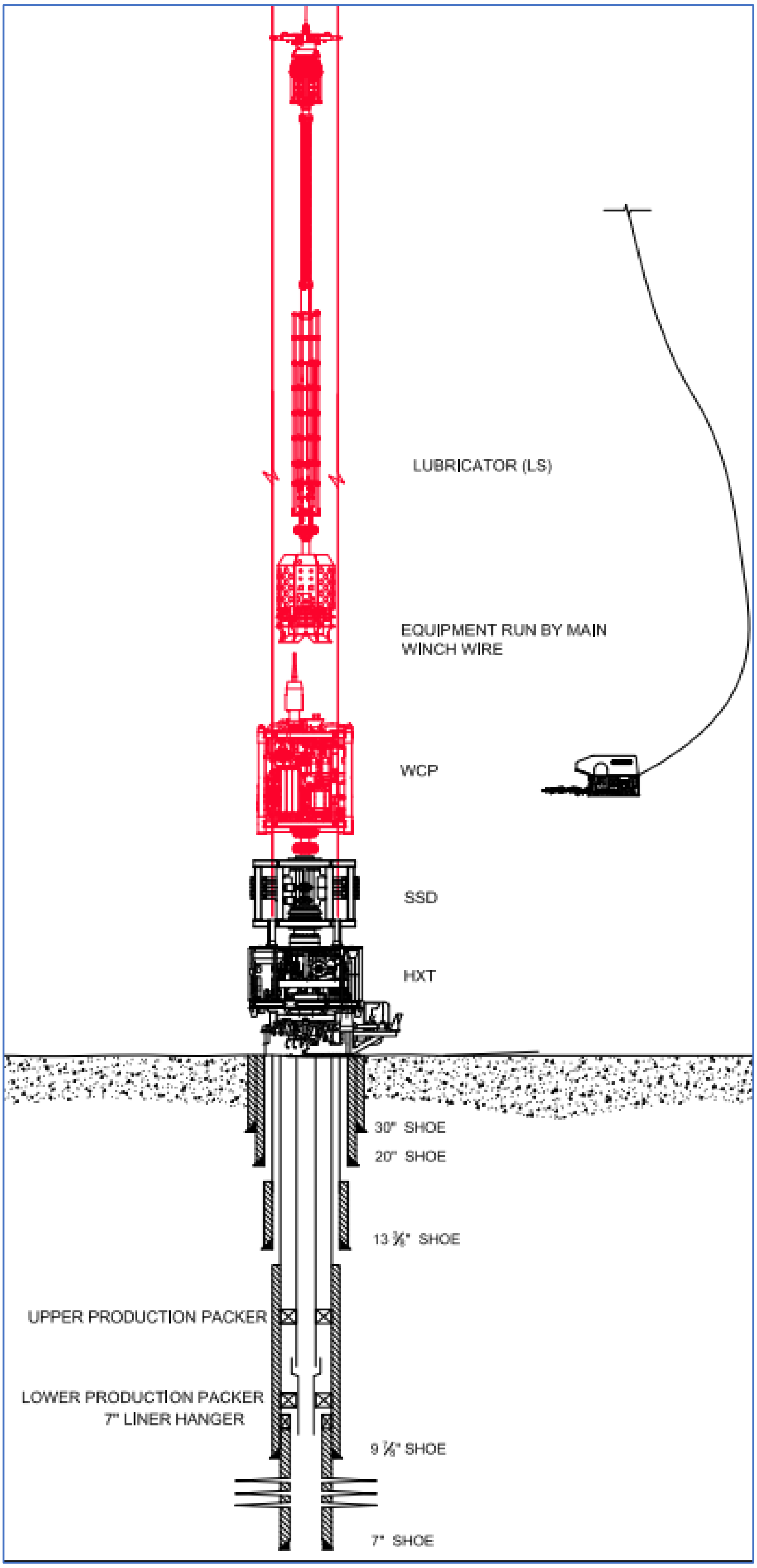

Figure 5-33: Installation of WCP and LS by use of the main tower winch. [65]

4. Installation of electrical and hydraulic hose(s)

When the well control equipment is in place, both the electric and hydraulic hoses are connected. This is done by use of an ROV. The hydraulic hoses provide with both low-pressure functions and high-pressure functions, while the electric hose provides power and communication interface modules to communicate with the XMT. Communication is usually provided through use of ethernet, but the ethernet signals may also be converted into Quadrature Amplitude Modulation (QAM) signals which provides a higher transfer rate at the cost of more noisy signals. [66]

When all well control equipment and hoses are installed, the NORSOK d-001 standard requires that the well control system shall be tested and documented with suitable recorders for both low and high pressures. All valves in the XMT is to be leak and function tested prior to any operations may commence. The standard states that the test procedure shall be executed in a safe and efficient manner on dedicated test stumps. [37]

5. Retrieval of crown plugs

When the well control equipment has been tested and verified the crown plugs may be removed. This is most commonly done by utilizing a spring jar run on a 7/32" wireline. There is a risk of not being able to properly latch on to the crown plug if there is too much debris on top of the plug. It is important that the tool string used while latching onto the plug is spaced out in such a way that it facilitates for cutting possibilities if loss of well control occurs. The perfect time spent retrieving a crown plug is usually between 3-4 hours depending on debris, water depth and latching system.

6. Perform a drift run (Caliper log)

In order to map the tubing condition in addition to verify the cement bonding to the production casing, a BHA including caliper and a noise logging tool is ran as described in section 5.5.2. These runs are typically run with a 7/16" e-line cable which supplies direct current to the tools used in the BHA. The data is stored in a memory unit in the tools and is analyzed when the tools are retrieved as the bandwidth on the current e-line cables are limited. The 7/16" wirelines are also stronger than the slickline used during retrieval of the crown plugs.

The main purpose of running the caliper tool is to verify that there is access down to the setting depth of the plug and identifying any possible restrictions. It is also performed in order to verify that the plug setting area is accessible and clean enough for plug placement.

While logging it is important to monitor the annular pressure for abnormal changes and ensure that this pressure is maintained within limits to avoid a potential collapse. It is also important to identify any possible areas where the BHA may become stuck prior to performing the run. Some caliper tools are also only operable while RIH and the tool may become stuck or damaged if the tool is retrieved out of hole with its caliper in opened position.

7. Installation of deep-set plug(s)

After the data from the drift run have been analyzed and the production tubing and casing condition have been verified, the wellbore may be isolated by installation of temporary deep-set plugs. The number of plugs that is used is dependent on the well configuration. In the example illustration below two plugs are set in order to maintain the NORSOK D-010 two-barrier philosophy after the well control equipment has been retrieved. [10]

As with the drift run, there is a risk of collapse while installing the plugs if the annular pressure become too large. Therefore, monitoring the internal and external pressures and identifying any sudden pressure changes is important. In addition, it is also important to consider any potential narrow areas detected during the drift run to ensure that the plug may not become stuck during deployment. Depending on the plugs setting mechanism there also exists a risk of activating the mechanism prematurely prior to reaching the plug-setting-depth. A stuck plug or an early release of the plugs setting mechanism could induce significant delays as a fishing operation would be very time consuming.

When the plug, or plugs, are installed in the desired locations, pressure testing may commence. It is desired to test the plug from below by use of an inflow-test, but if two plugs are utilized in the same well the upper plug must be tested from above. If the volume between the plugs are relatively small, a manometer may be used to verify that the pressure is not increasing between the plugs during the test. If the pressure between the plugs were to increase, it is likely that the upper plug is leaking. However, if the volume between the two plugs are larger, calculations using the pumped fluid volume and the fluid compressibility may be performed in order to verify that the upper plug is not leaking.

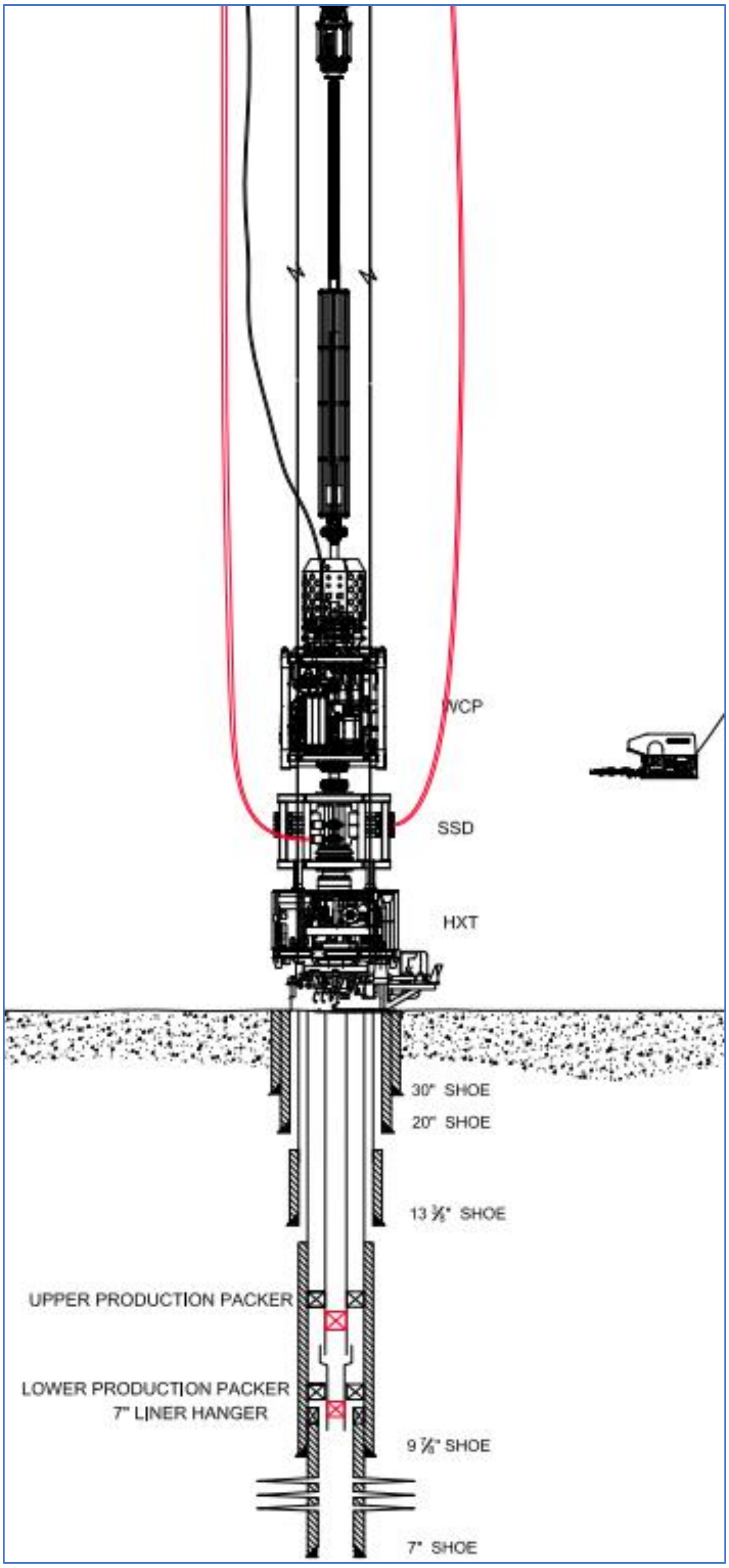

Figure 5-34: Install circulation hoses, retrieval of crown plugs, caliper/drift run and installation of two deep set plugs. [65]

8. Cut tubing above production packer

When the deep-set plug (plugs) is installed, cutting the production tubing is the next step of the operation. This procedure, along with various methods of cutting production tubing, have been discussed in section 5.5.3 – Tubing cutting tools.

An effect that may be experienced when cutting through the tubing, achieving connectivity to the annulus, is an effect called the u-tube effect. This effect is caused when you connect two tubulars filled with fluid of different densities. The hydrostatic pressure of the system will try to equalize, which induces flow of fluid. To avoid flow of fluid into the production tubing, it must be ensured that there is overbalance on tubing side. However, when using a HXT, the XMT will still be installed at this stage, which means that any potential returns may be taken out the PMV through a pipeline system back to the host platform.

To avoid damage to the casing when cutting through the tubing, the cutting tool must be configured to match the inner diameter and thickness of where the production tubing in place is to be cut. As mentioned in section 5.5.3, the point of cutting the tubing must be evaluated based on future plans for the well. Generally, if a tubing is to be replaced a cut shall be performed close to a coupling, whereas tubing that is to be removed for P&A purposes are often cut in tubing joints. Different types of cutting tools were also discussed in section 5.5.3, tubing cutting tools.

It is to be noted that the wireline control system, consisting of the WCP and the lubricator, is to be used during this step as the cutting tools are run on wireline.

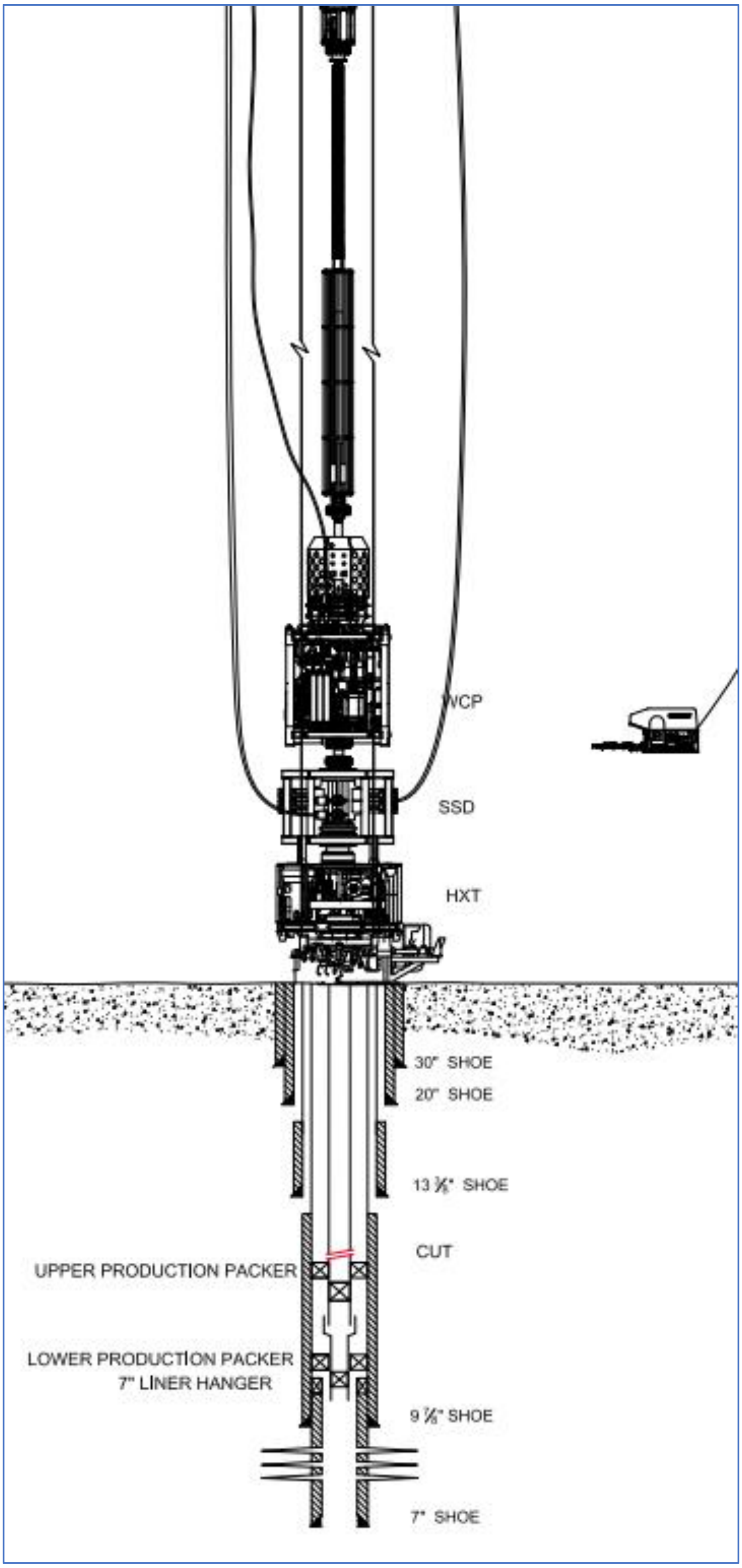

Figure 5-35: Tubing is cut on wireline above the upper production packer. [65]

9. Installation of upper crown plug and displacement of wellbore fluid

When a cut has been successfully verified through a circulation test, the final steps prior to retrieving the tubing may be initiated. To enable for the tubing retrieval the wireline control systems must be retrieved as the inner diameter of these are too small. However, since the wellbore at this stage is open, a crown plug must be installed in the tubing hanger to act as a barrier so that wellbore fluids may be circulated out of the well. The crown plug will be deployed by use of a slickline and it is therefore still need for the wireline control system.

When the crown plug has been successfully installed and pressure tested in the tubing hanger, the wellbore fluids may be circulated out of the well. This is done by displacing the well to treated sea water (TSW) or a Methanol and Glycol (MEG) solution in wells where hydrate may be an issue. The TSW or MEG will be reverse circulated into the well, meaning it will be pumped down into the annulus, and out through the production tubing. Potential holes or cracks in the production tubing at this stage may induce difficulties circulating out all the existing wellbore fluid. For this scenario a contingency plan must be created.

The fluid returns, which may be consisting of hydrocarbons or mud depending on the well, are planned to be transported through a flowline back to the host-platform as they have larger test facilities and fluid handling systems on board. As there are limitations regarding the tank capacity and separation system on the vessel that is planned to be used, and the vessel's 'poor boy' separator, which is already in place, may only handle small amounts of hydrocarbons at a time. However, it may in the future be relevant to increase the vessels tank capacity to enable for return of larger amounts of wellbore fluids to the vessel, although this have not yet been discussed in detail. When the well has been fully displaced to either TSW or MEG the next step may commence.

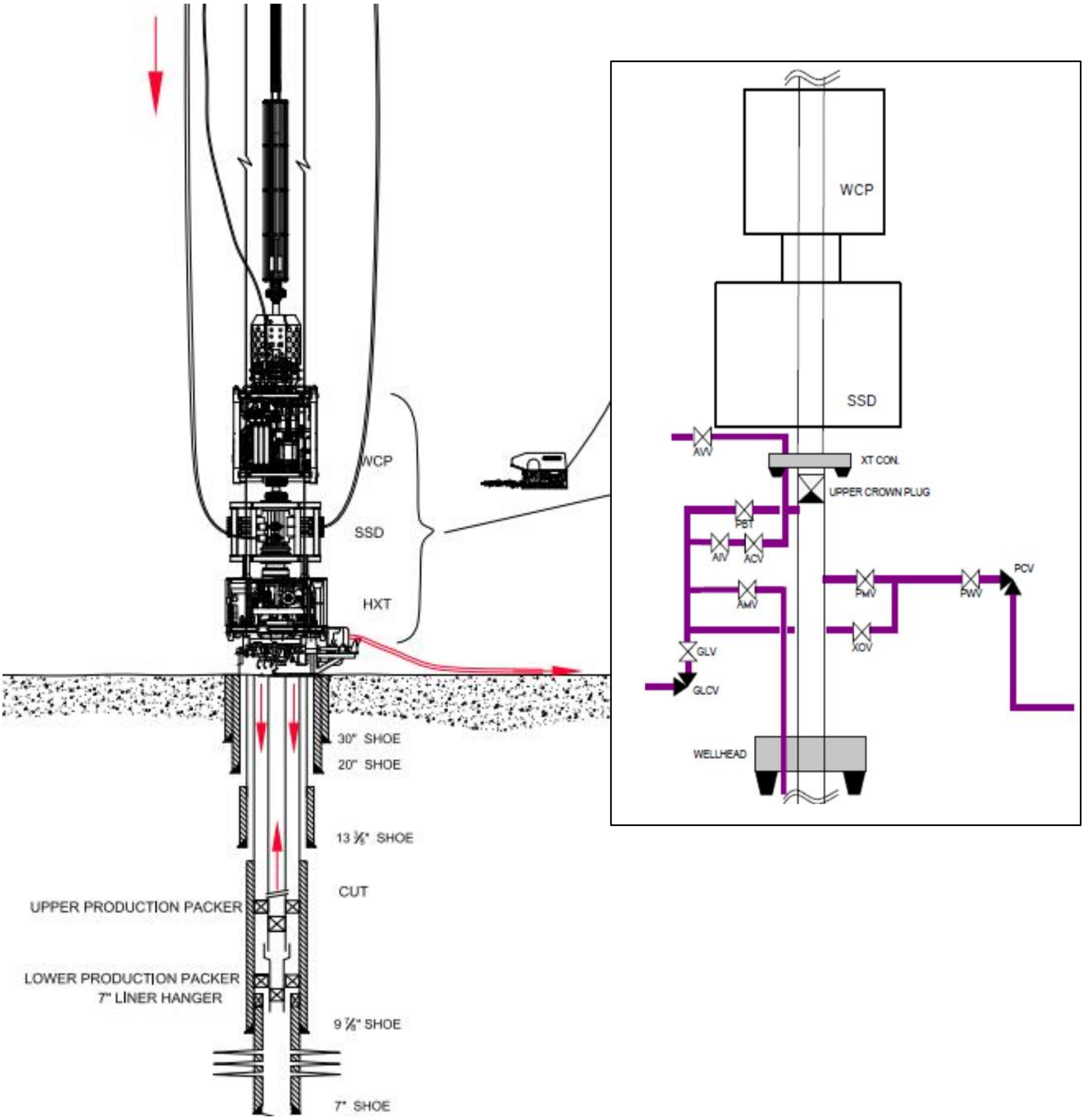

Figure 5-36: Installation of upper crown plug and displacement of wellbore fluid. Schematic of the HXT valves, the SSD and WCP. [65]

10. Retrieval of WCP and lubricator

The lubricator section and well control package is retrieved to surface while being monitored during transportation by an ROV. As for the deployment, guide wires will be used in order to avoid uncontrolled rotation of the heavy equipment. At this stage the wellbore will be isolated by use of either one or two deep-set temporary plugs and a tubing hanger crown plug. The SSD will act as a secondary barrier for wells with one deep-set plug, while it will act as a third barrier for wells with two deep-set plugs. Both the annulus and the tubing has also been displaced by either TSW or MEG and the well may therefore be assumed to be dead.

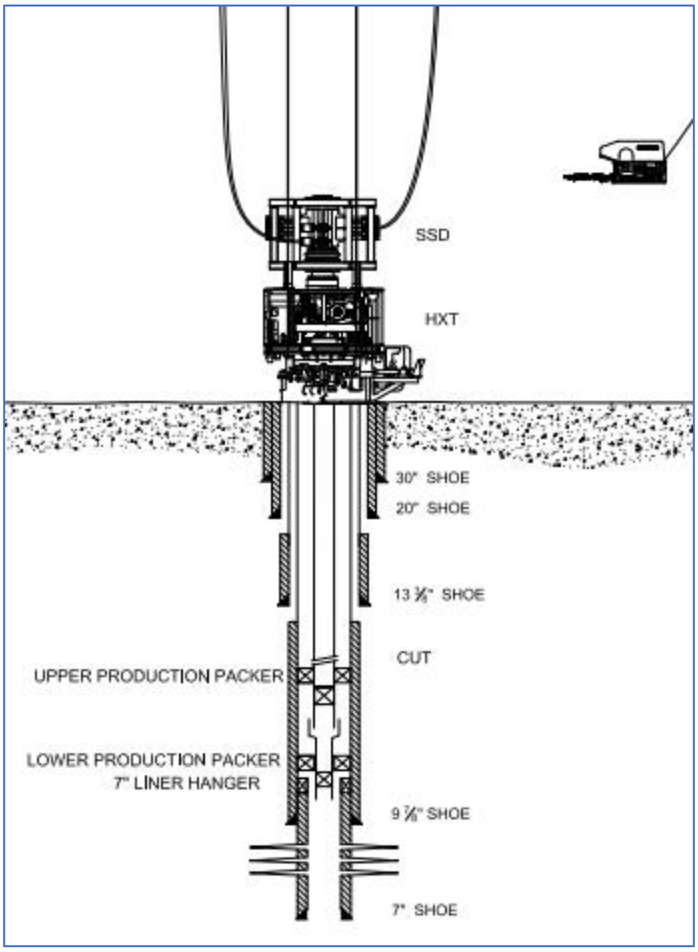

Figure 5-37: Retrieval of WCP and LS. [65]

11. Installation of volume control system and subsea jack

The VCS consisting of the modules described in section 5.5.4, will be installed in wells where only one deep-set barrier is placed. The WHIM will be installed on top of the SSD while the other modules such as pumps and control modules will be placed on the seafloor or elsewhere on the template. The purpose of this system is to monitor the fluid level in the well during tubing retrieval, as well as keeping the fluid level while retrieving the production tubing stable. It will also serve the function of identifying any unexpected changes in the fluid level in order to prevent uncontrolled flow from the well.

On top of the WHIM a subsea jack, used in order to achieve a greater pulling capacity while pulling loose the tubing hanger, is planned to be installed. This system was described in further detail in section 5.5.5.

Following the installation of the VCS and the subsea jack, the crown plug placed in the tubing hanger will be retrieved, and the next step may commence.

13. Run tubing hanger retrieval tool (THRT) on drill pipe (DP)

With all the necessary equipment in place, and the crown plug removed, the next step of the operation is to run the retrieval tool on drill pipe. To enable for this, the tubing hanger will need to be pulled loose. The tubing hangers in HXT have in many cases sat in the XMT for many years, carrying the load of the tubing string. Due to this, most tubing hangers will need additional pulling force than only its buoyed gravitational self-weight to be pulled loose. However, experience has shown that the required pulling weight does not usually exceed 300 metric tons. This means that by using a subsea TH release jack with a pulling capacity of 350 tons the solution will be sufficient for most tubing retrieval operations.

When the THRT is landed in the TH, the subsea jack will grip around the drill pipe and supply additional hydraulic pulling force on demand. Pulling force will be supplied step wise until the tubing hanger is loose as described in chapter 5.5.5.

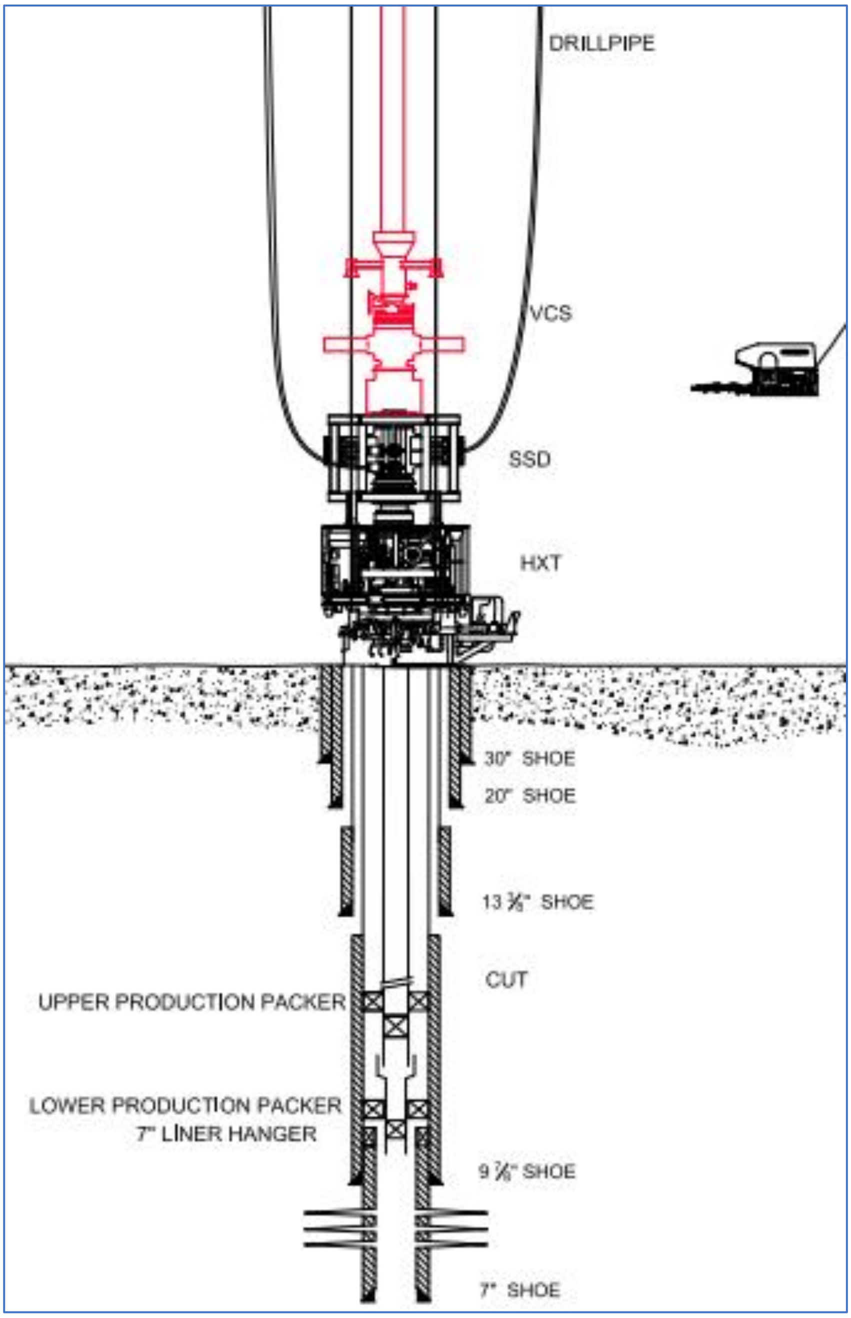

Figure 5-38: Deployment of VCS, retrieval of upper crown plug and running of THMRT on drill pipe and land in TH. [65]

14. Release tubing hanger and pull DP and tubing to surface

When the tubing hanger has been pulled loose from the HXT, the drill pipe will be retrieved while having the subsea jack, tubing hanger and tubing attached to it. How the pipe handling process is performed is described in detail in section 5.5.6. The tubing and the drill pipes will be elevated by use of either a hydraulic or mechanical elevator connected to the vessels main winch system. One of the main reasons to utilize this winch is that it already has an active heave compensating system incorporated, which is crucial for work on relatively small vessels that are exposed to heave. The section length of the tubing that is to be cut is decided by the length between each coupling. The tubing is hung off by slips gripping onto the tubing just below the tubing coupling, to then be cut by the surface cutter around 30 cm above the coupling. The tubing section will then be transported to the mezzanine deck for storage. The elevator will then grip on to the tubing sticking up, the slips will release, and the next tubing section will be pulled up. This process is repeated until the whole tubing length is retrieved.

During the retrieval the SSD will act as the secondary or tertiary barrier, while there will be either one or two temporary plugs placed below the cut tubing acting as primary or secondary barriers. The volume control system will be used in order to keep the fluid level in the well stable in addition to identifying any sudden fluid level changes in the well as described.

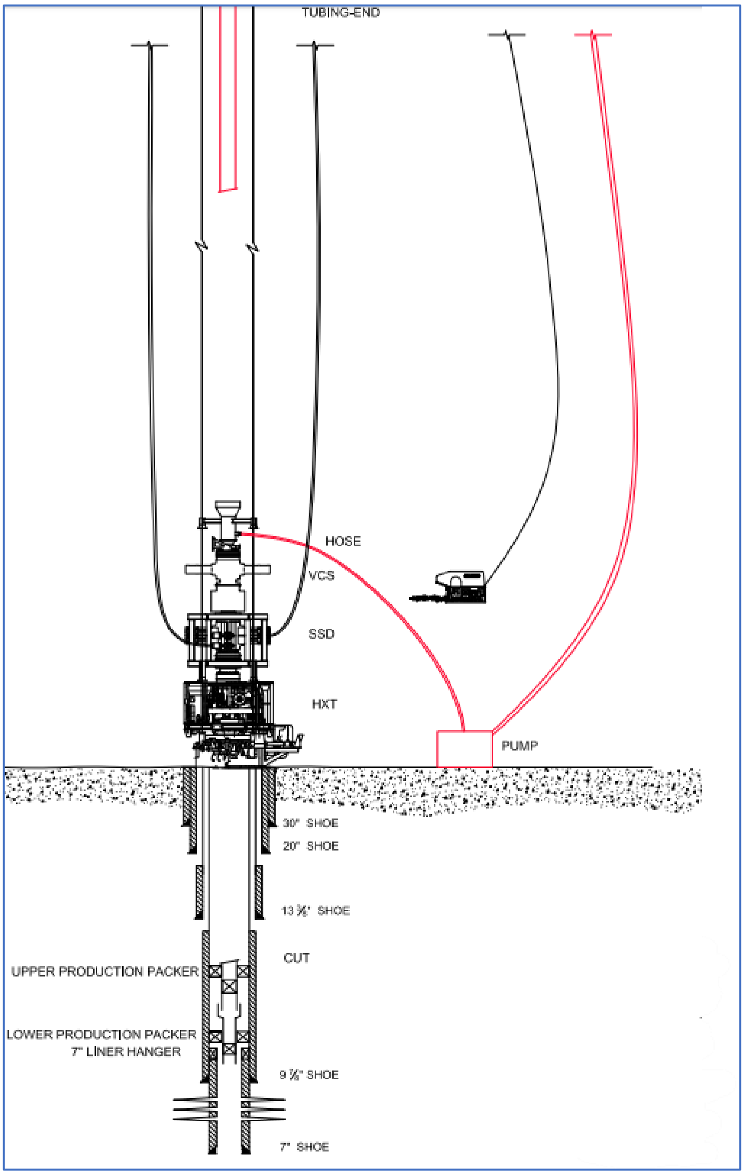

Figure 5-39: Installation of VCS hoses, release TH and pull drill pipe and tubing to surface. [65]

15. Set bridge plug in production casing

When the tubing has been fully retrieved to the surface the next step is to install a bridge-plug in the production casing to act as a temporary environmental barrier. Regulations require that the well pressure in wells that is planned to be abandoned for more than one year shall be monitored. However, since there in the discussed scenario have been installed minimum one deep temporary plug in addition to the bridge-plug in the production casing, there will be at least two barriers against the reservoir and monitoring will not be required. [10]

As for the upper most deep-set plug, the bridge-plug set in the production casing must be pressure tested from above. In this scenario there will not be a need for a manometer below the plug as the volume between the bridge-plug and the deep-set plug is large enough to allow for verification through compressibility calculations of the pumped fluid volume. This means that potential leak through the plug would be identifiable through compressibility calculations.

When the plug has been set and tests have verified that it is not leaking, the next and final step in the operation may commence.

16. Retrieve VCS, SSD (and HXT)

Before leaving the well, the remaining well control systems in addition to the HXT must be removed. Firstly, the WIM placed above the SSD is released and retrieved along with the other components of the volume control system. Secondly the hoses connected to the SSD is dethatched and retrieved, followed by retrieval of the SSD by use of the main tower winch. As for the deployment, guide wires will be used in order to avoid uncontrolled rotation. Transportation and handling of such heavy equipment are preferred to be executed under nice weather conditions as mentioned earlier in this chapter.

The final step before the well is left, is to retrieve the HXT to surface and install a debris cap on top of the WH.

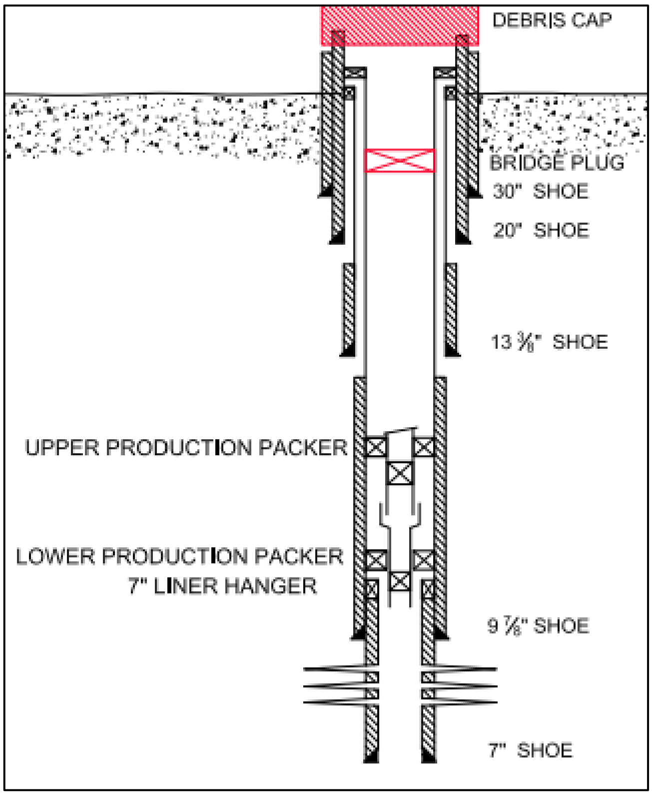

Figure 5-40: Set bridge plug in production casing. Retrieval of VCS, SSD and HXT. Installation of debris cap. [65]

5.7 Conclusion

Projects like this are important for the industry to move forward. In the coming years, there will be need for an extensive amount of P&A operations, and development of solutions that prove to be both time and cost efficient is therefore highly important. Although there are several challenges still to be solved regarding fully rigless P&A, operations such as the rigless tubing retrieval may be used as a foundation for development of new technology. Investments must be made to start off such projects, and the business case will not always be positive for the first campaigns. Therefore, it is important that thorough planning is performed, that results in generalized solutions that may be utilized for as many wells as possible without the need for any major upgrades in the future.

As of writing, the tubing retrieval project has not yet been finalized and there may still challenges that needs to be solved as not all of the discussed equipment have been manufactured. During the project, challenges have been discovered, while solutions have been identified through consultations with experts within various fields as well as implementing unconventional solutions while still maintaining operational safety.

In general, well control and HSE has been and will be the highest priority for Equinor as an operator during the preparatory work. One of the main discoveries of work performed so far, have been to verify that completing rigless tubing retrieval operations should be possible with the current technologies, while still complying with the rules and regulations in the NCS. There have in addition been developments regarding the challenges related to the technical requirements described in the thesis. Thus, it is important that standards and guidelines are updated and revised to include new operations and solutions to allow for further development of technology without compromising the overall safety of the operations.

Although the operations have yet to be performed, the main operational challenge may prove to be the limited amount of deck space in and idle time due to rough weather conditions. In addition, the solutions presented in the thesis are also primarily based on operations for wells with simple well configurations and only minor well problems. Performing operations on problematic wells with constrictions or well control issues should however be possible with the current solution, as more campaigns are completed, and experience is gained. It is likely that the first campaigns will contribute to optimizing the solutions so that as many well scenarios as possible may be included in the rigless tubing retrieval scope. Further, as challenging situations are encountered, contingencies must be made, which again contributes to experience and knowledge being gained.

The initial plans were to perform the first operations in the end of 2020. Due to delays caused by contractual agreements and long lead times of key components, the project was postponed, and the operations were set to begin in early 2021. However, as the COVID-19 pandemic has caused uncertainties within the industry and for the future campaigns, the project has as of writing been put on hold with the intention of being continued at a later stage. Though, it is still likely that the rigless tubing retrieval operations will be executed during 2021.

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