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Abstract

The world's portfolio of oil and gas wells are ageing. Plug and abandonment is the final and inevitable stage of every well. As a result, decommissioning is set to grow steadily in the coming years, as more and more wells are reaching the end of their life cycle. This forces the oil and gas industry stakeholders to increase their attention toward decommissioning activities. Well decommissioning is associated with high expenditure where taxpayers are on the hook for as much as 50% to 80% of these expenditures. Operators are looking for cost-efficient technology and equipment to plug and abandon their wells. Drill rigs' daily rental rates are the highest cost associated with well decommissioning; therefore, an increasing number of operations have been moved to vessels with considerably lower day rates.

Subsea wellhead terminator is an ongoing project in BHGE, which aims to transfer a field proven rig-based technology over to rigless.

This thesis's main contribution is to investigate the business potential for the subsea wellhead terminator. We have estimated demand on the number of subsea wellheads to be plugged and abandon on different continental shelves. The calculated cost of developing and testing the project is less than 1 MNOK. To evaluate the market, a competitor analysis of other large oilfield service companies and how they position towards future well decommissioning activity has been conducted.

Problem Description

There will be increasing activity within decommissioning since the oil and gas industry is becoming more mature. Operators are looking for cost-efficient solutions to replace the high cost and low availability issues of conventional rig-based abandonment, with rigless technology. Baker Hughes, a GE company (BHGE), wants to be competitive in a future rigless market. Therefore, they started a pilot project called subsea wellhead terminator, which aims to transfer their mechanical rig-based wellhead cutter over to rigless.

This thesis will do the following:

- Investigate the business potential for BHGE’s subsea wellhead terminator.
- Estimate the number of subsea wellheads that needs decommissioning.
- Investigate the challenges associated with P&A, and how to address them.
- Analyze the competitors and investigate how they position themselves for the future rigless decommissioning market.

Acknowledgements

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We would like to thank our supervisor at University of Stavanger, Petter Osmundsen, who gave us precise feedback and lifted the thesis to a higher level.

Our gratitude goes to Baker Hughes, a GE Company, to the external supervisors Jarle Hvidsten and Ole Petter Nipen for letting us be a part of the subsea wellhead terminator project. The two have provided us with continuous feedback and guidance throughout the thesis. Their experience and knowledge have been greatly appreciated.

Thank to our spouses Alette and Natalie for support throughout the thesis.

Abbreviations	
ALARP	As Low As Reasonably Possible
APR	Abandonment Performance Review
AWJC	Abrasive Water Jet Cutting
BHGE	Baker Hughes a GE Company
BOP	Blowout Preventer
EAC	Element Acceptance Criteria
GE	General Electric
GOM	Gulf Of Mexico
HC	Hercules Cutter
HXT	Horizontal X-mas Tree
ID	Identification
LCV	Light Conventional Vessel
LWIV	Light Well Intervention Vessel
MD	measured depth
MODU	Mobile Offshore Drilling Units
NCS	Norwegian Continental Shelf
NOK	Norwegian Kroner
NORSOK	Norsk Sokkels Konkurranseposisjon
NPD	Norwegian Petroleum Directorate
NPT	Non-Productive Time
NPV	Net Present Value
OGA	Oil & Gas Authority
OPSAR	Oslo and Paris Conventions
P&A	Plug and Abandonment
PSA	Petroleum Safety Authority Norway
PWC	Perforate, Wash and Cement
QHSE	Quality, Health, Safety and Environment
R&D	Research and Development
RLWI	Riserless Lightweight Well Intervention
ROV	Remotely Operation Vehicles
SSR	Semi-Submersible Rig
TIOS	TechnipFMC and Island Offshore Subsea Company
UK	United Kingdom
UKCS	United Kingdom Continental Shelf
USD	United States Dollar
UWRS	universal wellhead retrieving system
VXT	Vertical X-mas Tree
WB	Well Barrier
WBE	Well Barrier Element
WBS	Work Breakdown Structure

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1 Introduction

This thesis is part of the pilot project subsea wellhead terminator, which is an ongoing internal project in Baker Hughes, a GE Company (BHGE). The project concept is to develop and test a subsea wellhead cutting and retrieval tool for rigless decommissioning. The aim of the project is to transfer BHGE's field proven universal wellhead retrieving system (UWRS) from a rig-based to a rigless operation.

The prime objective of this thesis is to gather available data relevant for plug and abandonment operations to provide BHGE with an estimation of the future market and calculate the cost for developing and testing the subsea wellhead terminator. Thus, increasing activity within decommissioning is a result of wells reaching their end of life. The oil and gas industry are entering a new phase, with decommissioning taking its appropriate place alongside exploration and production activity. Every well that has been drilled will at some point need to be decommissioned.

In this thesis, the final phase of plug and abandonment (P&A), which consist of cutting and retrieving of the wellhead and conductor is the focus. With the increasing decommissioning activity worldwide, the number of wellheads that need to be cut and pulled is increasing. It would be beneficial to have as much information as possible on the exact number of subsea wellheads in each field around the world. This number would give a clear indication of the future demand, but since there are not any international statistics on this subject, estimates based on available data from different regulation authorities are presented.

Through extensive research on the future market of well abandonment, all sources agree that there is an increasing number of wellheads due to decommissioning. The benefit with estimating demand in decommissioning is that every well drilled must at some point be decommissioned.

Well decommissioning prevents contamination of the outside environment by sealing off a section of the well to prevent flow between different formations and hydrocarbons reaching the surface.

1.1 Research Questions

This thesis will answer the following research questions.

- What is the cost of developing and testing the subsea wellhead terminator and what is the business potential?
- What is the estimated number of subsea wellheads that needs to be decommissioned?
- How can the challenges associated with the decommissioning be addressed?
- How are the competitors positioned towards a rigless P&A market?

1.2 Structure of Thesis

The remaining part of this thesis will be structured the following way:

- Chapter 2 explains how the project became a master thesis and which methods been used to gather data and other necessary information.
- Chapter 3 introduces the subsea wellhead terminator project.
- Chapter 4 theory on general life cycle of an oil well, the reasons for abandoning a well, and rig-based and rigless is introduced.
- Chapter 5 gives an overview of the regulations and guidelines associated with P&A activity on the Norwegian continental shelf (NCS), while phases and complexity on United Kingdom continental shelf (UKCS) is introduced.
- Chapter 6 describes the procedure of abandoning a well, divided into the different phases.
- Chapter 7 explains how technology and operations are being transferred from rigbased to rigless. With an example of a multiwell rigless phase 3 campaign.
- Chapter 8 explains the purpose of subsea wellheads and how they have evolved over time.
- Chapter 9 describes mechanical and abrasive water jet cutting technology for wellhead removal.
- Chapter 10 describes and explains the most common challenges associated with P&A activity and gives a description on how to address them.
- Chapter 11 describes what a one-stop shop contract is and how BHGE can strengthen their position as a one-stop shop contractor by implementing the subsea wellhead terminator.

- Chapter 12 Competitor analysis of BHGE´s main competitors on the Norwegian market and comparing of the technology used for wellhead removal.
- Chapter 13 gives the estimated number of subsea wellheads on the various oil fields around the world.
- Chapter 14 gives the calculated cost for developing and testing of the subsea wellhead terminator.
- Chapter 15 discuss the main results of this thesis.
- Chapter 16 concludes this thesis with main findings.
- Chapter 17 recommendations for further research.

2 Research Method

This thesis was completed in close collaboration with the project managers of the subsea wellhead terminator project in BHGE. This thesis investigates the project's business potential. The research method in this thesis started with clarifying and formulating goals, by meetings and interviews with BHGE personnel and supervisor from UIS to formulate the main objective of the thesis. The results of this phase were the definition of what the thesis should cover. The thesis will contribute as a business case for the project because BHGE can use the results of the thesis to assess whether the project should be developed further.

The next phase was a literature study to analyse the activities of well decommissioning to better understand the process and technology used in well decommissioning. The literature in the thesis is from: publications, industry reports, news reports, literature, presentations from conferences, academic articles and reports on decommissioning. Information regarding the project was provided by BHGE. This phase also mapped the available information on the topic and identified where the information was lacking.

The technology trends in the decommissioning market were evaluated by attending the Norwegian Petroleum Society Decommissioning Conference 2019 in Stavanger. Here, key topics and recent trends in decommissioning in the North Sea were discussed. [1].

In the literature phase there was also collected empirical evidence on offshore wells. Here petroleum safety authority (PSA) and Norwegian Petroleum Directorate (NPD) provided empirical datasets and guidance on how these could be analysed quantitatively.

The last phase was to evaluate and present the interpretations of the findings. The focus was to objectively evaluate and present the research data collected in the literature study.

To validate the results many sources were compered, and the researchers made interpretations since the data presented in the sources varied.

At the end of Chapter 10 to 14 there will be discussion and interpretations of the results.

2.1 Data collection

After a dialogue with BHGE, the researchers decided estimating the wells that needed to be plugged and abandoned in the future would be beneficial for the further development of the subsea wellhead terminator. The estimation of wells gives a strong indication of the demand for well decommissioning. Empirical data on subsea wells was collected, considering all subsea wells have a subsea wellhead, the number of subsea wells is most relevant for the development project

The research focus was thus to collect data on subsea wellheads. Collecting data on the NCS was a main objective since this is where the equipment will be used first. This assumption is based on the project being developed in Norway and that large service companies, like BHGE, see the NCS as a place to test new technology [2].

Data collection on the number of wells was conducted, the data was collected by contacting several regulators to obtain relevant data. Mail correspondence and phone interviews with employees in PSA, NPD, Oil & Gas UK and OPSAR were also performed. The communication with the official regulators provided useful data and insight into decommissioning activities.
Data collection was difficult because the information on subsea wells was not gathered and centralized by any official organization. Private companies have information on installed equipment around the world. When these companies where contacted they explicit said that the data was only available for purchase. Collected data had large variations and was contradictory. The approach was to use source criticism to examine and analyse different sources.
Since both authors were working at BHGE, the information collection as well as other work on the thesis, was convenient. Being a company employee meant that all framework for information sharing was governed by company established confidentiality agreements. Therefore, confidential drawings and operating service procedures for components used to develop the project prototype could be shared.
Employment at BHGE also meant that key personnel was accessible throughout the research. The personnel helped by answering questions related to the thesis and provided guidance. Being a part of a large organization means there is many resources available, including information on the company’s products and technology, in addition to its operational track record. The operational track record includes where and how the technology was used, as well as how it performed.

3 Subsea Wellhead Terminator

The subsea wellhead terminator is an ongoing internal project in BHGE. The aim of the project is to develop and test a subsea wellhead cutting and retrieval tool for rigless decommissioning. This is achieved by transferring BHGE's field proven UWRS from a rig-based to a rigless operation.

This sections purpose is providing insight into the project. The project team is introduced and how the project started. A description of the development plan and how the subsea wellhead terminator assembly work, and which parts it consists of.

3.1 Project team

Jarle Hvidsten is a technical advisor in BHGE with experience in pressure control. Hvidsten has been involved since the beginning and is the project manager.

Ole Petter Nipen is an Operation Manager in BHGE with experience from fishing services. Nipen has been involved in the project since its beginning and could be defined as the project champion [3].

Andre Aasen is a project coordinator in BHGE on subsea wellheads. He has been involved in the project coordination and is one of two authors of this thesis.

Sander Stavland is a project coordinator in BHGE on subsea wellheads. Has been involved in the project coordination and is one of two authors of this thesis

Figure 1 - Project Team

In this thesis, the project team refers to these four people.

3.2 Project introduction

The subsea wellhead terminator is a new method for removing subsea wellheads and is currently under development by BHGE in Norway. The idea for the project started when employees in BHGE realized that the UWRS is best in class for rig operations and drill pipe deployed system. However, the employees understood for vessel deployed systems that removed subsea wellhead, BHGE was not able to compete its competitors.

The merger of Baker Hughes and GE Oil and Gas brought employees from different sectors and companies with different technologies together. This project began from the merger as this led to a discussion at a coffee machine between new colleagues in BHGE. One colleague was from Baker Fishing and one was from GE Oil & Gas, with experience from pressure control equipment from Vetco Grey, a company acquired by GE. The two colleagues soon realized that by combining legacy products from Baker Hughes and GE Oil & Gas they could have a system for removing subsea wellheads. The two colleagues started by developing the concept idea into a project. The project would be developed locally because the main assets were in Norway.

3.3 Development Plan

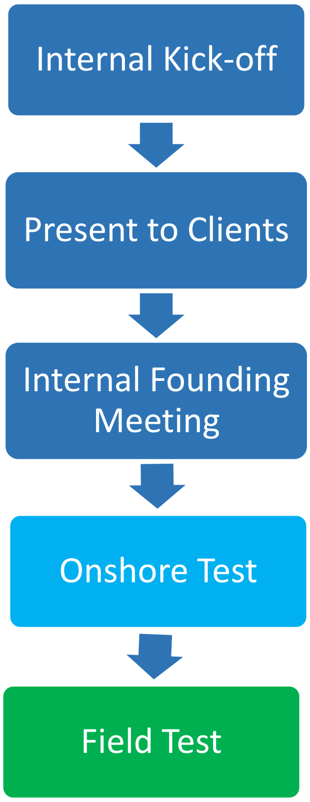

Figure 2 - Project Development Plan

The project team than made a development plan for the prototype. The first step was the internal kick-off meeting, where the concept was presented to management. Management was positive and agreed to the next step: to involve clients. In the client meeting, it was pointed out that rigless wellhead removal was a gap in BHGE portfolio. For the client, this meant increased competition that could help to reduce the cost of well decommissioning. They wanted to witness the onshore test and if they liked what they saw, an offshore field test would be performed. This outcome was above BHGE's expectations for the meeting. The internal founding meeting was held to get allocated resources to the project. Here, some content of this thesis was presented. The meeting was successful, and management gave founding to develop and test the prototype. The decision to fully commercialise the concept had to be decided later.

Significant efforts have been made to get the onshore test while this thesis is being written, unfortunately unforeseen events delayed the test.

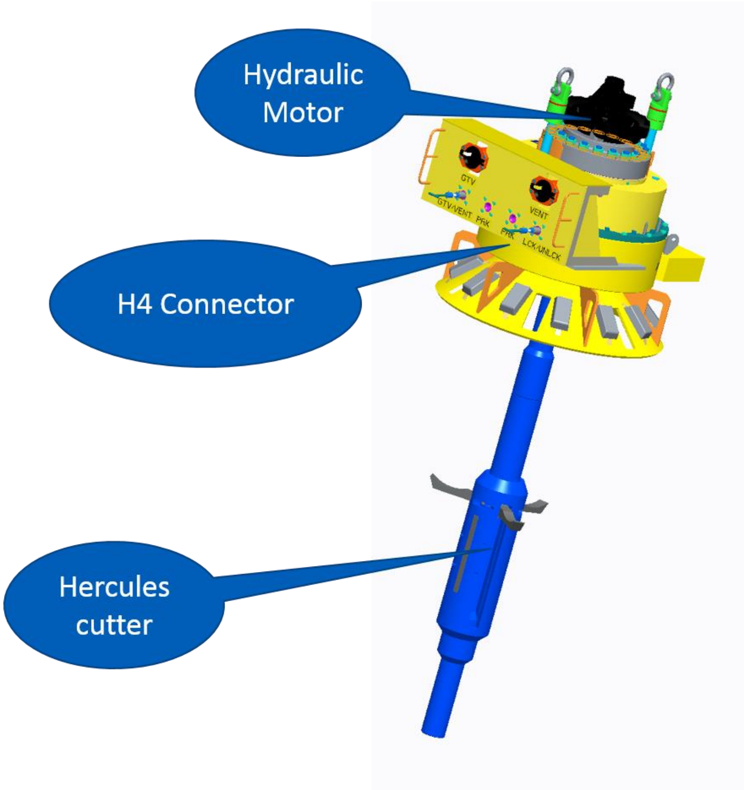

Figure 3 - Subsea Wellhead Terminator Assembly

3.4 The Prototype Test

The test will be performed by cutting of a 36 x 20-inch wellhead. The wellhead will be lowered down into a subsea pool in a workshop in Bergen. The freshwater pool will simulate an offshore environment, and the water will also have a lubricating and cooling effect. The project team will be involved and present in the test, and the testing team will benefit from the continued involvement of personnel that engineered the project.

3.5 The Concept

The concept combines the hercules cutter (HC) and MD H4 wellhead connector to one assembly that could cut and retrieve subsea wellheads.

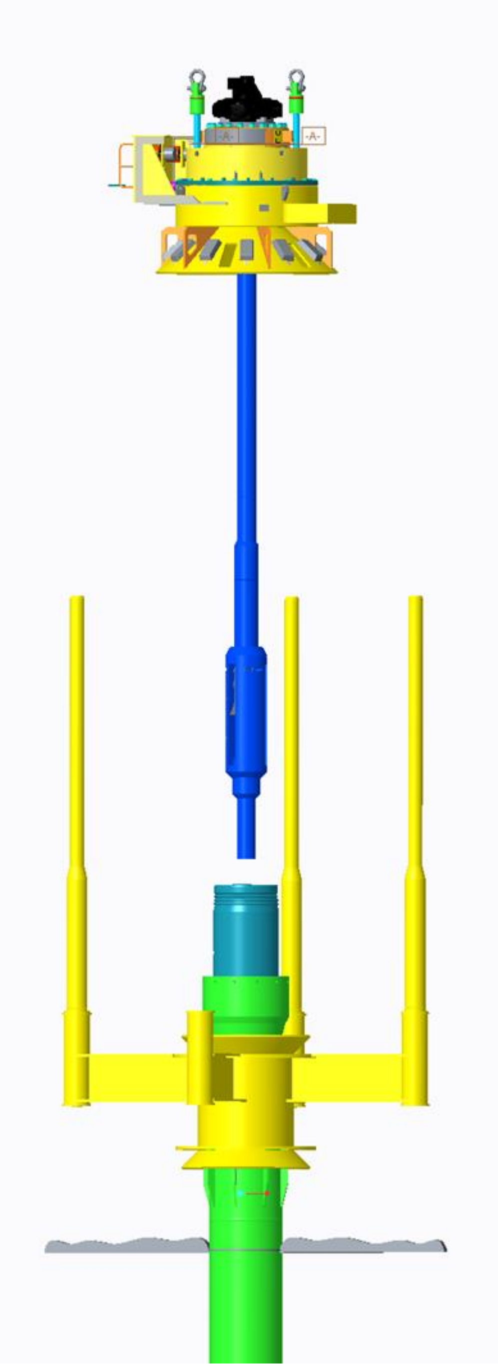

Figure 4 - Terminator entering a subsea wellhead with permanent guide base

The components are described later in this section. The assembly would be lowered to the seabed on a wire and could be run from a vessel.

The assembly needs an ROV to guide the connector in place on top of the high-pressure housing. It is normal for subsea operations to have a ROV in the water for guidance, monitoring and performing workover tasks.

Running the assembly requires hydraulic force from the ROV. The hydraulic force is needed to pressure activate the knives on the HC and to operate the hydraulic motor that rotates the HC

.

The assembly must contain other components to successfully connect the main components. The components needed in the assembly are as follows: HC, H4 connector, hydraulic motor, drill pipe x-over, special flange.

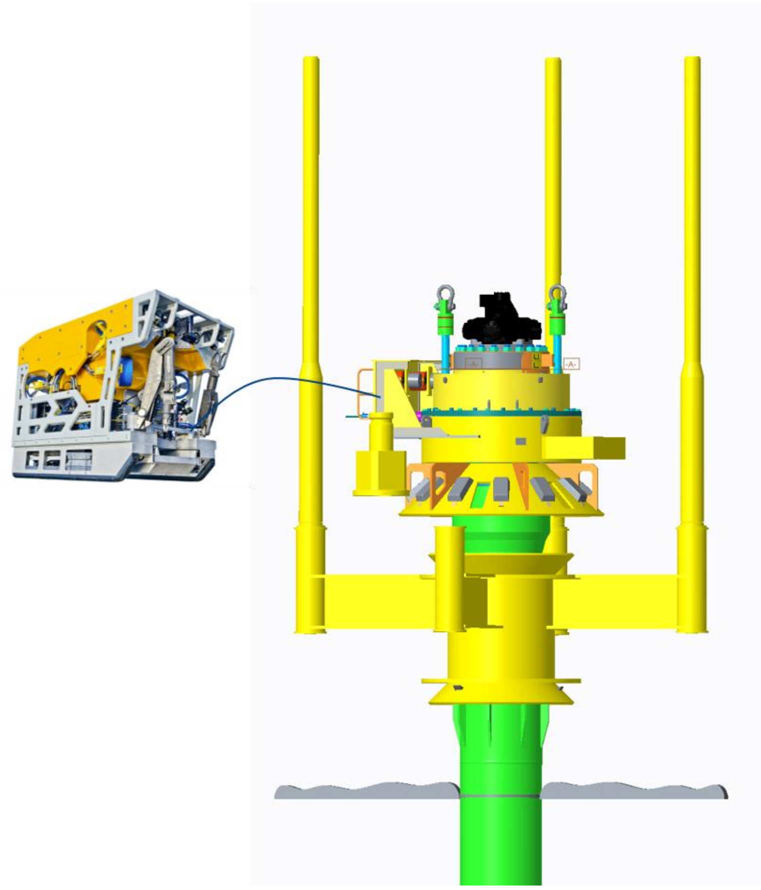

Figure 5 - Terminator landed on a subsea wellhead being operated by ROV

3.5.1 Hercules Cutter

The HC is a multi-string cutter designed to cut single or multiple layers of casing. This will be the component that performs the actual cutting.

The tool is operated on drill pipe which transmits drilling fluid via mud pumps and torque from the top drive to the HC. When the HC is lowered to the required cutting depth, the drilling fluids acts on a piston that engages the knives. The HC is rotated by a mud motor located above the tool. The motor utilizes the circulation of the mud to rotate the cutter.

3.5.2 H4 Connector

H-4 is the profile on all subsea wellheads. The wellheads have the male connection while the Blow Out Preventer (BOP) and connectors have the female connection. This GE patented design has been adopted by the industry and has become standard on subsea wellheads. The design is simple to operate, providing a metal-to-metal seal, and the profile has high tensile load capabilities. The connector has a ROV interface with a hot stab connection to operate the connector. The ROV connections need to be modified so the interface is connected through the flange and the hydraulic lines goes to the HC below.

The MD-H4 connector used in the subsea wellhead terminator is a modern hydraulically operated, field proven H4 connector.

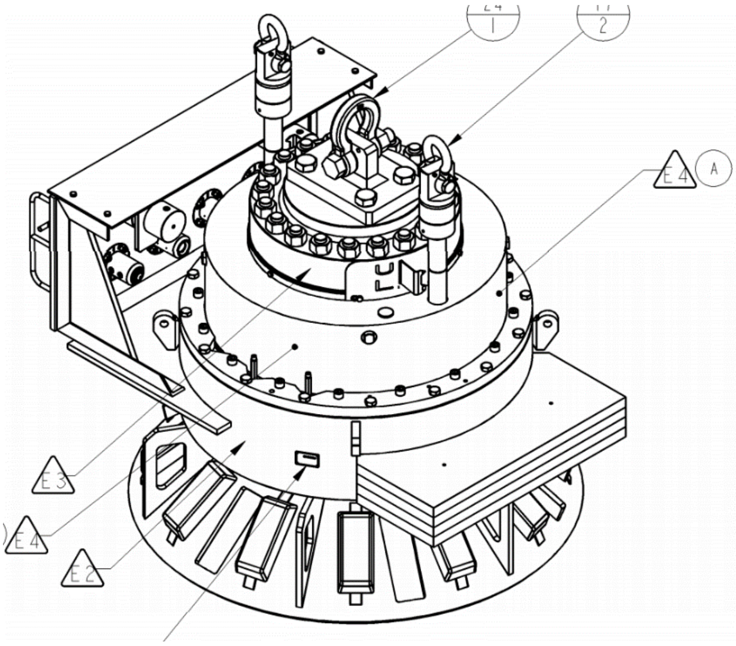

Figure 6 - MD H4 Connector

4 Background

This chapter contains a description of decommissioning and introduces rig-based and rigless well decommissioning.

Oil and gas fields on the NCS starts to mature, and an inevitable cessation of production approaches. Decommissioning is a non-profitable activity with high expenditure for the operators.

One of the main cost drivers in well decommissioning is the rental cost of mobile offshore drilling units (MODUs). MODU is rig-based vessels and includes jack-up rigs, semi-submersible rigs (SSR) and drillships. To reduce the high expenditures, the industry is trying to move as much of the MODU operation over to lower cost vessels, such as riserless light well intervention (RLWI) vessels with a considerably lower day rate.

Research on methods for transferring technology to vessels that will perform these operations in a cost-efficient manner is therefore essential [4].

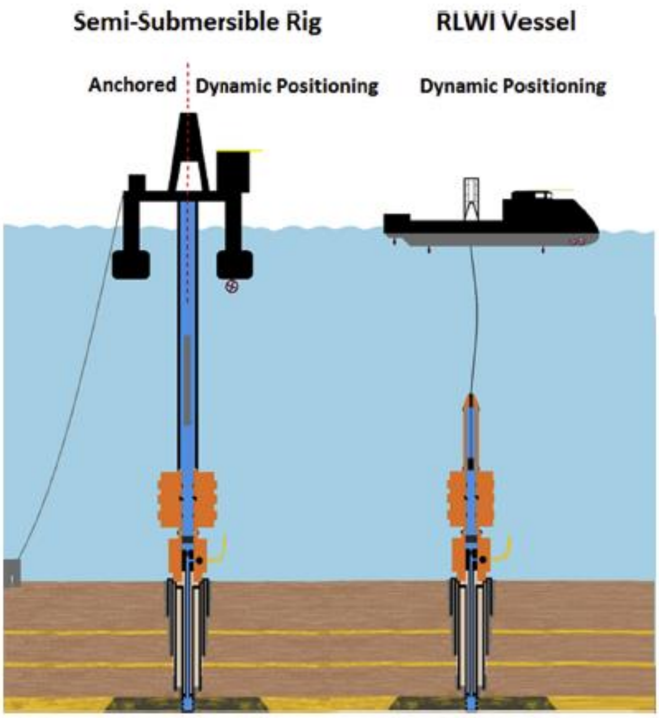

Figure 7 - Illustration of SSR (left) and RLWI vessel (right

Cost estimation for P&A has proven to be difficult, due to the vast number of variables and the uniqueness in design of each well. Each well is unique and needs to be documented and investigated prior to abandonment. Documentation from wells drilled decades ago can be incomplete or missing, and for some wells the status will be unknown. The cost of P&A for a well will depend on vessel or rig availability, cost development in the industry, when the operation is begun and whether the P&A is completed singly or in campaigns. In the past, well abandonment was completed quickly and with little focus on the environment. Today the main goal for all regularities is to prevent fluid migration from the reservoir to surface as well as crossflow into another reservoir. There shall be no trace of drilling and well activities on the seabed after leaving the area [5].

The typical lifespan of an oil field is described in Figure 8. First a well is drilled in an area where operators believe there is a petroleum deposit. When a petroleum deposit is discovered they will drill an exploration well to identify the extent and size of the deposit before a production well is drilled. Then, the production builds until it reaches a steady plateau. Production stays on this plateau for a while before it gradually starts to decrease. Eventually, the production will diminish to an economic limit, where production income cannot cover expenses. This means the well is moving toward its last phase, the abandonment phase. The operator can then check whether production form another part of the field is profitable and drill a sidetrack into a new area of the reservoir. If this new area is not profitable, the well will be temporary or permanently abandoned. Temporary abandonment is chosen if the operator intends to resume or re-enter the well later or postpone the permanent P&A. Permanent P&A is chosen when the intention is to never re-enter the well. Throughout this thesis P&A is used for permanent P&A. The predicted plug wave is estimated to start in the early 2020s and continue for decades, involving thousands of wells on the NCS [6] [7].

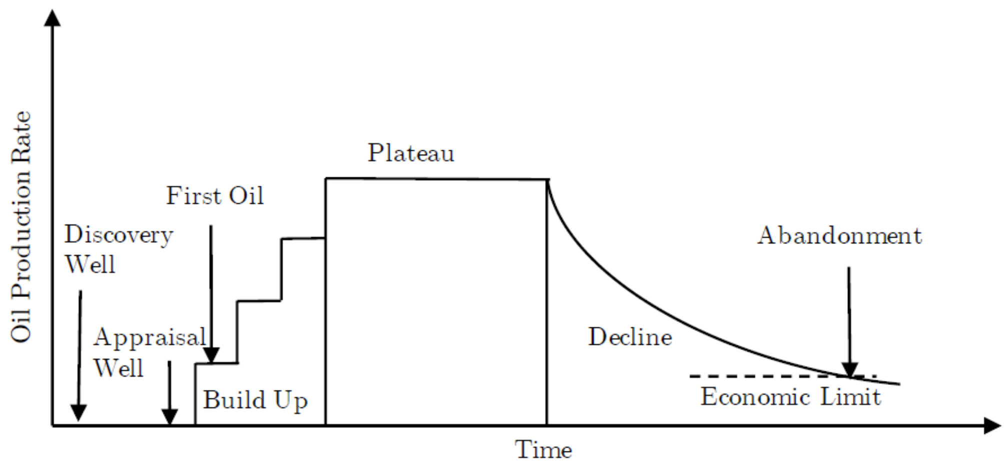

Figure 8 -Typical lifespan of a field. [6]

Plug and abandonment is the process of installing a permanent or temporary barrier to seal a well or a section of a well to prevent flow between different formations or hydrocarbons and the well's surface. There are three reasons to abandoning a well [8]:

- **Cease of production:** *"The wells will be permanent P&A when it is no longer profitable to produce from a well or to re-use part of the well"*.
- **Slot recovery:** *"This process involves permanent P&A of the old well track prior to sidetrack drilling into a fresh area of the reservoir"*.
- **Abandonment of pilot holes and exploration wells:** *"The well is P&A immediately after all essential information is gathered"*.

5 Well Decommissioning Theory Rules and Regulations

In this chapter the most important regulations and requirements concerning P&A is given. Such as NORSOK-D010 which is the guidelines for well integrity and includes well decommissioning. There is also an introduction to the UK classification system of wellheads, to give an overview over the regulations and requirements in the industry.

The Norwegian Petroleum Act (Act 29 November 1996 No. 72 relating to petroleum activities) provides the general legal basis for the licensing system that governs Norwegian petroleum activities. This act covers application of licences, exploration, construction, production and the plans for field cessation, including the decommissioning plan. The act states:
"*anyone who conducts or participates in petroleum activities shall comply with legal provisions, including regulatory decisions which are made pursuant to the Petroleum Act. More specifically, this duty requires such parties to actively seek to bring identified discrepancies into compliance* " [9]

The Petroleum Safety Authority (PSA) is the government supervisory and administrative agency for oil and gas activates on the NCS. All requirements and guidelines must comply with the Petroleum Act [10]. The NORSOK is made in correspondent with the management in different oil companies to ensure quality, health, safety and environment (QHSE) during operation. NORSOK's purpose is to make activity on the NCS more cost-efficient by increasing value, reducing cost and eliminate unnecessary activities. NORSOKs purpose is to add value, reduce cost, save time and eliminate unnecessary activities in offshore field developments and operations. NORSOK sets the minimum requirements for equipment and solutions to be used in a well, but it leaves the operating companies to choose the solutions that meet the requirements. The operation companies are fully responsibility for their compliance with the standard.

5.1 NORSOK D-010

The NORSOK D-10 standard "Well integrity in drilling and well operations" defines requirements and guidelines relating to well integrity and well activities. The standard focuses on establishing well barriers by using well barrier elements, their acceptance criteria, their use and monitoring of integrity during their life cycle.

The main requirement is to ensure the well integrity is maintained throughout its lifetime. According to NORSOK D-010, there shall always be two well barriers during well activities and operations [8].

To understand how the NORSOK D-010 works, some of the definitions are provided:

- **Shall** *"verbal form used to indicate requirements strictly to be followed in order to conform to this NORSOK standard and from which no deviation is permitted, unless accepted by all involved parties"*
- **Should** *"verbal form used to indicate that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others, or that a certain course of action is preferred but not necessarily required "*
- **Source of Inflow** *"a formation which contains free gas, movable hydrocarbons, or abnormally pressured movable water "*
- **Well Integrity** "*application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well".*
- **Well Barrier (WB)** *"envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment"*
- **Well Barrier Element (WBE)** *"a physical element which in itself does not prevent flow but in combination with other WBE's forms a well barrier "*
- **Well Barrier Element Acceptance Criteria (EAC)** "*technical and operational requirements and guidelines to be fulfilled in order to verify the well barrier element for its intended use"*
- **Well Barrier Schematic (WBS)** *"a WBS shall be prepared for each well activity and operation. WBS should be made when a new component is function as WBE, as an illustration of the well and a final status of the permanently abandoned well".*
- **Permanent well barrier** *"permanent well barriers shall extend across the full cross section of the well, include all annuli and seal both vertically and horizontally. The well*

barrier(s) shall be placed adjacent to an impermeable formation with enough formation integrity for the maximum anticipated pressure. "

- **Primary Well Barrier** *"first well barrier that prevents flow from a potential source of inflow"*
- **Secondary Well Barrier** *"second well barrier that prevents flow from a potential source of inflow*" [8]

5.1.1 Well Barrier

Chapter 4 "General principles" in NORSOK D-010 describes the specific well activities and operations. The chapter includes well barrier, well design, risk assessment and verification, and different emergency procedures with supervision and reporting [8].
NORSOK D-010 states that a WBS should include the following information:

- A drawing illustrating the well barriers, with the primary barrier in blue colour and the secondary barrier in red.
- The formation integrity when the formation is part of a well barrier.
- Reservoirs or potential sources of inflow.
- Listing of WBEs with initial verification and monitoring requirements.
- All casing and cement labelled with its size and depth.
- Relatively correct position of components in relation to each other.
- All well information, name, type, status, well design pressure, revision number and date.

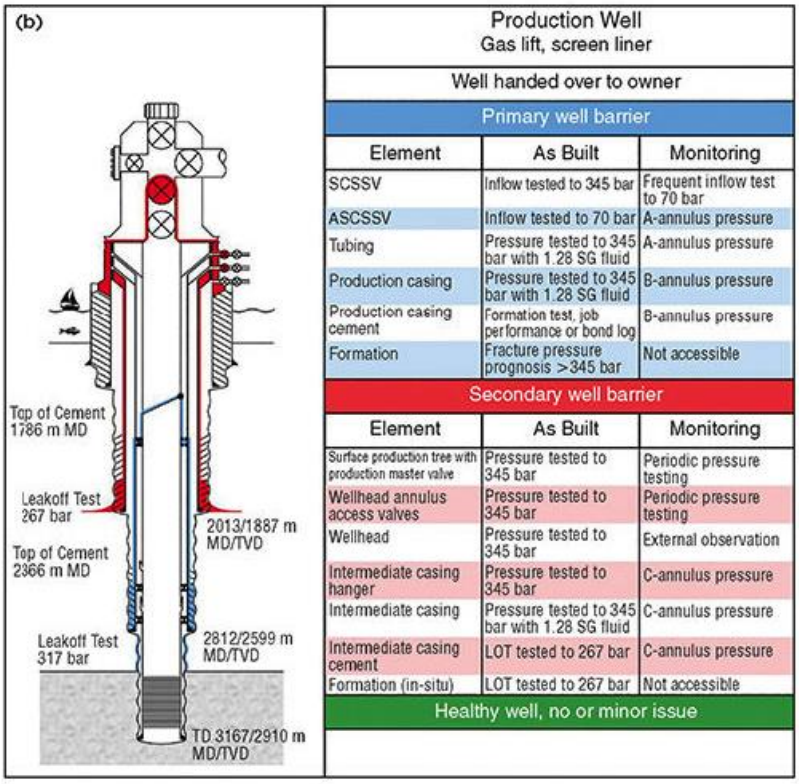

Figure 9 - Well Barrier Schematic [11]

According to NORSOK D-10 the minimum of well barriers presented in Figure 10 shall be in place: [8]

Minimum number of well barriers	**Source of inflow**	
One well barrier	a)	Undesirable cross flow between formation zones
	b)	Normally pressured formation with no hydrocarbon and no potential to flow to surface
	c)	Abnormally pressured hydrocarbon formation with no potential to flow to surface (e.g. tar formation without hydrocarbon vapour)
Two well barriers	d)	Hydrocarbon bearing formations
	e)	Abnormally pressured formation with potential to flow to surface

Figure 10 - Minimum number of well barriers

5.1.2 Temporary and Permanent abandonment

In Chapter 9 “Abandonments activities” in NORSOK D-010 divides P&A into two different P&A operations: temporary and permanent. For the remainder of this thesis, we refer to permanent P&A as P&A.

- **Temporary Abandonment with Monitoring**
  “Well status where the well is abandoned, and the primary and secondary well barriers are continuously monitored and routinely tested. If the criteria cannot be fulfilled, the well shall be categorized as a temporary abandoned well without monitoring. There is no maximum abandonment period for wells with monitoring”
- **Temporary Abandonment without monitoring**
  “Well status, where the well is abandoned, and the primary and secondary well barriers are not continuously monitored and not routinely tested. The maximum abandonment period shall be three years”
- **Permanent Abandonment**
  “Well status, where the well is abandoned and will not be used or re-entered again. Permanently abandoned wells shall be plugged with an eternal perspective taking into account the effects of any foreseeable chemical and geological processes” [8]

5.1.3 Permanent Well Barrier

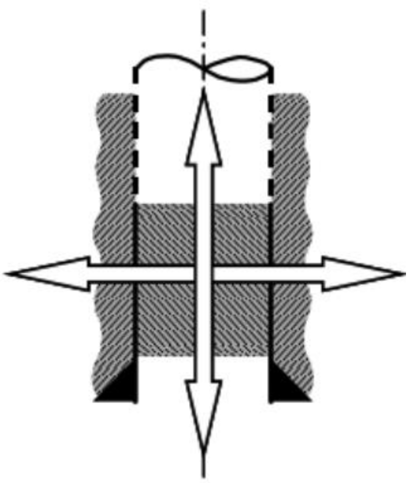

Figure 11 - Well Barrier expanding over the entire wellbore

A permanent well barrier shall be placed as close to the reservoir as possible and placed where it is good formation strength.

The barrier must cover the full cross section of the well, including all annulus and seals, both vertically and horizontally, as illustrated in Figure 11. Removal of downhole equipment is required when the equipment can cause loss of well integrity. Control lines and cables shall not be a part of the permanent well barrier [8].

According to NORSOK D-010 [8], a well plug should have the following characteristics:

- Long-term integrity
- Impenetrability
- No shrinkage
- Ability to withstand mechanical loads and shocks
- Resistant to chemicals such as H2S, CO2 and hydrocarbons
- Have a good handle for steel
- Do not damage the integrity of tubulars

Permanent well barriers shall be abandoned with eternal prospective. There are several barriers and test to fulfil a permanent P&A operation. The purpose of the well barrier is to isolate the petroleum bearing reservoirs and others pressure zones to prevent future hydrocarbon leakage to the environment. The well barrier must remain in place and be reliable for the future.

Generally, at least three well barriers will be placed in each well, and some specific wells also require crossflow well barriers. NORSOK D-010 has specific criteria for the well barriers in a P&A operation:

- **Primary barrier:** *"To isolate a source of inflow, formation with normal pressure or over-pressured/ impermeable formation from surface/seabed".*
- **Secondary barrier:** *"Back-up to the primary well barrier, against a source of inflow".*
- **Crossflow well barrier:** *"To prevent flow between formations (where crossflow is not acceptable). May also function as primary well barrier for the reservoir below".*
- **Open hole to surface well barrier**
  "To permanently isolate flow conduits from exposed formation(s) to surface after casing(s) are cut and retrieved and contain environmentally harmful fluids. The exposed formation can be over pressured with no source of inflow. No hydrocarbons present". [8]

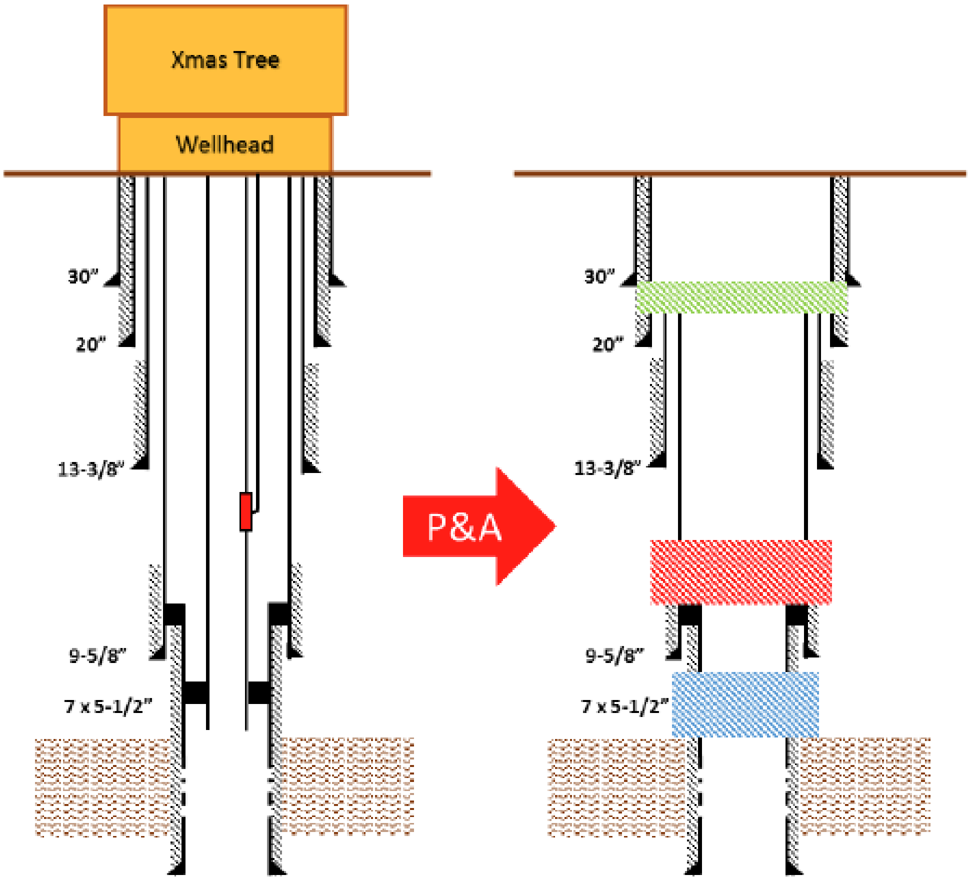

Figure 12 - Well schematic before and after P&A

5.1.4 Permanent Well Barrier Element Acceptance Criteria

For a permanent WBE to be accepted, it must satisfy the criteria in NORSOK D-010.

The minimum cement plug length shall be the following:

- Open hole cement plugs of 100 meters with minimum 50 meters above any source of inflow/leakage point
- Cased hole cement plugs of 50 meters, if set on top of a mechanical/cement plug as foundation otherwise 100 meters.
- Open hole to surface plug of 50 meters if set top of a mechanical plug, otherwise 100 meters.
- Shall extend across the full cross section of the well
- It shall be positioned at a depth where anticipated pressure does not exceed minimum formation stress.

All plugs shall be verified by either logging, tagging, pressure test or a combination of these certification methods.

5.1.5 Removing Wellhead

According to NORSOK-D010 the wellhead and casing shall be removed below the seabed at a depth which ensures no stick up in the future. Cutting depth shall prevent conflict with marine activities. When cutting the wellhead soil and local conditions should be considered. Mechanical or abrasive cutting is the current preferred method for removal of casing and conductor at seabed. [8]

5.2 Well Barrier Schematic

A WBS is required for each well activity and operation. The well schematic was designed to illustrate the presented well barrier envelope. Each WBS requires a minimum of two well barriers and is often referred to as the "hat over hat" principle, see Figure 13. For each well the first hat is the primary barrier illustrated in blue, and the second hat is the secondary barrier illustrated in red. Well schematics must be delivered by to government regulators by operating companies, according to NORSOK.

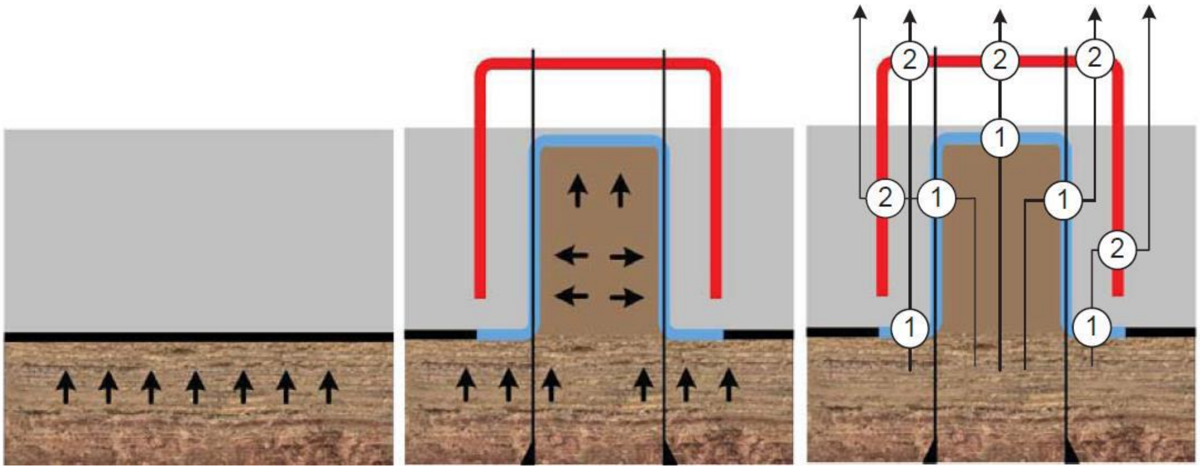

Figure 13 - Hat over hat principle [12]

5.3 P&A Phase Description

In the oil and gas industry, P&A operations are divided into different phases.
NORSOK D-010 does not differentiated P&A operations into phases, complexity and location as Oil & Gas UK does in its “Guidelines on Well Abandonment Cost Estimation“ [11].

Oil & Gas UK divides P&A’s operational sequence into three distinct phases: reservoir abandonment, intermediate abandonment, and wellhead and conductor abandonment.
Each phase is reflected in terms of complexity reflecting which vessel and technology that are required to perform the work scope in the specific phase.
There are five categories of complexity: no work required, simple rigless, complex rigless, simple rig-based and complex rig-based. These categories allow the wells to be assigned unique codes, which identify the type of vessel or rig required for the different phases and wells [12].

The well location is divided into three: surface well, subsea well and land well. This thesis focuses on subsea wells as this is where we can implement rigless well abandonment. We divide P&A operations into four phases to include a preparatory work phases which is suitable for a riserless light well intervention (RLWI) vessel to perform ahead of the P&A operations.

5.3.1 Phase 0

Preparatory Work - Preparatory work is where the well is killed by injecting heavy drill fluids into the well, mechanical plug is set, punching and cutting of tubing. Removal of trawl structures and tree caps. If the subsea well has a vertical x-mas tree it could be retrieved in this phase [11].

5.3.2 Phase 1

Reservoir Abandonment - This phase consists of isolating the well from the reservoir and is performed by installing primary and secondary barriers to isolate all hydrocarbon or water-bearing zones. The normal practice is to pull the tubing, but it may be left in place.

5.3.3 Phase 2

Intermediate Abandonment - This phase includes setting the barriers to the upper hydrocarbon or water-bearing permeable zones. Also includes retrieval of casing or milling and isolation of liners.

5.3.4 Phase 3

Wellhead and conductor removal - - This is the final phase of a well and is completed when no future operation is required on the well. The phase includes cut and retrieval of the wellhead, conductor and casing strings [13].

5.4 Plug and Abandonment Complexity

Further each of the phases is divided by complexity of the well decommissioning operation required [14].

- **Type 0:** No work is required; a phase or phases of abandonment work may already be completed
- **Type 1:** Simple rigless abandonment, using wireline, pumping crane, jack-ups and RLWI vessel
- **Type 2:** Complex rig-less abandonment, using coil tubing, pumping crane and jack-ups; subsea completed wells will use heavy duty well intervention vessels with riser.
- **Type 3:** Simple rig-based abandonment, requires retrieval of tubing and casing.
- **Type 4:** Complex rig-based abandonment, may have poor access and poor cement, requiring retrieval of tubing and casing, milling and cement repairs.

5.4.1 Well Complexity Matrix

The two categories described above are useful since they reflect the complexity and amount of work required to complete a P&A operation.
The information about abandonment phase and well complexity can be implemented into a matrix to illustrate the amount of work required to P&A a well. Table 1 illustrates how a matrix would appear for a phase 3 subsea wellhead removal, where phase 0 to 2 is completed and only the removal of the wellhead is remaining.

Phase ↓ Complexity →	0 No work required	1 Simple Rigless	2 Complex Rigless	3 Simple Rigbased	4 Complex Rigbased
0 Preparatory work	1				
1 Reservoir Abandonment	1				
2 Intermediate Abandonment	1				
3 Wellhead and Conductor removal		1			

Table 1 - Well complexity matrix of phase 3 well

By coding all wells on UKCS and NCS into matrices showing the complexity of each phase would give operators the opportunity to calculate the total decommissioning cost. If each phase with corresponding complexity is given a duration and an estimated vessel cost, this code system could benefit both the operator and service companies in estimating time duration and cost for larger campaigns. Using the well complexity matrix system, operating companies could collaborate and use allocated vessels or rigs for different phases of the campaign, and service companies could tender an offer for phases or whole campaigns.

5.5 Oslo Paris Convention (OSPAR)

All countries that signed the Oslo-Paris convention (OSPAR) must follow its regulations, which determine that offshore installations should be removed and only in special circumstances be left in place after end of life.

"OSPAR" is from OS in the Oslo convention and PAR in Paris Convention, which was established 22 September 1992 in Paris, but entered into force 25 March 1998. Today, OSPAR includes fifteen EU countries. The purpose of OSPAR is to protect the North-East Atlantic marine environment.

The Oslo-Paris convention decision 98/3 on the disposal of disused offshore installations states "the dumping, and leavening, wholly or partly in place, of disused installations is prohibited within the maritime area". Concrete installation over 10,000 tonnes, the parliament decides whether it should be removed. Facilities not to be reused or left on the field must be transported to land and handled by approved land facility for recycling or disposal. Thus, OSPAR monitors the development of offshore installations and maintains an updated inventory of all oil and gas installations offshore. The database includes the name and ID number, location, operator, water depth, production start, current status, category and function of the installations [15] [16].

6 Well Abandonment Procedure

This chapter is a continuation of the previous chapter, here it is illustrated how the regulations are used in practice. The most common steps in a well abandonment procedure is explained here. The various operation is divided into the UK phase system to show what is included in the different phases of well decommissioning.

Well abandonment procedure involves installing permanent well barriers to seal a well and prevent crossflow or migration of hydrocarbons to the surface. All wells are unique, but all must go through the similar steps to be P&A. These steps can be summarized as follows:

- Connecting to wellhead and killing the well
- Removal of X-mas tree
- Cutting and pulling of tubing and lower completion
- Installing well barriers
- Cutting and retrieving the wellhead, conductor and casing string

6.1 Phase 0: Killing the Well

When arriving at the well, the tree cap must be removed to be connected to the wellhead. Then, the well is killed by bullheading fluids into it and forcing production fluids back into the reservoir. Bullheading is accomplished by pumping heavy fluid with higher density, so the hydrostatic pressure is higher than the formation pressure and the production fluids will return to the reservoir [17].

This activity will eliminate the need for pressure control equipment at the surface. After the well is killed, the deep mechanical plug is set. This will than act as a temporary barrier against the reservoir. The service company then punch and cut the tubing on wireline and the circulate heavy fluid down the tubing and into the annulus. A diagnostic logging run can be performed at this stage to assess the quality of downhole equipment and well condition [18].

6.2 Phase 1: Pulling Tubing and Lower Completion

Pulling the tubing and lower completion is a heavy job, varying between 100 and 150 tons of lifting operation. Therefore, this task is performed by rigs because there are control lines attached to the blow out preventor (BOP) and logging behind casing is necessary. The tubing can be left inside the hole during the P&A operation, but the normal practice is to pull the tubing. If there are no control lines in the barrier area and the quality of the cementing barrier inside and around the tubulars are checked and logged, the tubing can be left inside. There is no accurate technology to log multiple casing strings, which is why it is common practice to pull production tubulars [18] [19].

6.3 Phase 2: Installing Well Barriers

Before setting the well barriers in the reservoir, logging by wireline is performed to determine the quality of the cement inside the annulus. If the casing cement is quality, the cement can be established inside the casing. The well barrier must include all annulus, extending to the full cross section of the well and seal both vertically and horizontally. As mentioned, there are no multi casing logging tools, so to log behind the casing, the casing must be pulled. If interpretation of the logging data indicates poor quality cement, then use perforate, wash and cement technology (PWC) to set a strong well barrier. Until a multi casing logging tool is on the marked, PWC will be the fastest and most efficient way to set well barriers.

6.3.1 Establish Surface Barrier

The surface barrier is a 'fail safe', where a potential source of inflow is exposed after, for example, a casing is cut. If the casing cement quality is high, establishing the barrier inside the casing is sufficient. However, it is normally necessary to pull the 9-5/8" casing (if it is not pulled in the previous phase) and continue to pull the 13-3/8" casing to establish a full cross section barrier inside the well. Finally, a bridge plug should be installed as a barrier fundament and cement barrier should be established.

6.4 Phase 3: Cut and Retrieval of the Wellhead, Conductor and Casing

The final phase of the permanent P&A operation is to remove the upper part of the conductor, wellhead, and casing strings. According to NORSOK D-010, the wellhead and casings shall be removed below the seabed at a depth that ensures no wellhead stick up in the future. Technology used to cut the wellhead and conductor is mechanical cutting and abrasive water jet cutting technology [12].

7 Wellhead systems

The wellhead systems serve as the termination point of casing and tubing strings. This is where casing and tubing is hung from and where the interface between the well and drilling and production systems are located. The control pressure provides access to the main bore of the casing tubing and to annulus. This pressure-controlled access allows drilling and completion activities to occur safely and with minimal environmental risk. Multiple barriers are in place inside the well, sealing and isolating between casing when multiple casings strings are installed. The sealing allows for pressure monitoring and access to annulus between the different casing strings [20].

The wellhead provides a connection to connect the BOP when drilling and to the x-mas tree when going into production. Wellheads are always located under the x-mas tree. A subsea well is when wellhead and x-mas tree is located on the seabed, also called “wet” wells. Surface is when conductor goes to a wellhead on the lower part of the platform, and the x-mas tree is on top. Surface or platform installation is often called a “dry” well.

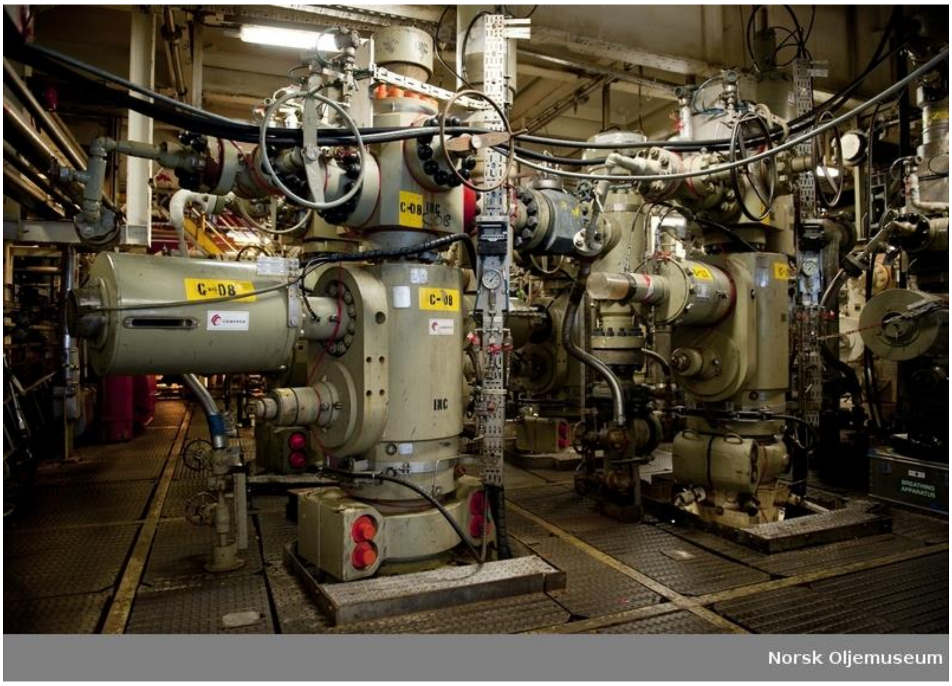

Figure 14 - Surface wellhead located on Statfjord C

7.1 Subsea Wellhead

A subsea wellhead is what the subsea wellhead terminator is being developed to cut and retrieve. Subsea wellhead starts with a low-pressure housing that is typically 30 or 36 inches. The low-pressure housing is the foundation of the well and has an interface for the high-pressure 18 ¾ inch. The high-pressure housing has a landing shoulder to hang off the casing loads and provides a metal-to-metal seal for the seal assembly sealing of the different casing hangers. The subsea wellhead has a male connection that connects to the BOP female connector.

The main difference between the surface and subsea wellhead is that the surface wellhead is located above water and therefore is much easier to access. The surface wellhead also allows access the different annulus between casing strings and tubular, while the subsea wellhead only provides access to annulus A, between the production casing and tubular [21].

Figure 15 - Subsea wellhead with permanent guide base located on UIS campus

7.1.1 Evolvement of Subsea Wellheads

In recent years, subsea wellheads have become larger, and the walls on the housing and the extension joints have become thicker. This change has resulted in more challenging subsea wellhead cutting operations.

The new wellheads have been designed to withstand higher fatigue because the BOP and the drilling rigs are larger than before. The new BOP's are designed to withstand pressure up to 20,000 psi and have pipe rams and blind shear rams to work in this environment. The new requirements for the BOP have made it larger in size. When the BOP is larger, the drilling rigs must be modified. Heavy BOP's impart more fatigue loading into the wellhead, and they may be too heavy in the case of a rig drift off [22].

Consequently, drilling rigs have become larger to handle and operate the new BOPs. Modern drilling rigs are designed to operate in harsh environment and deep water. Aa a consequence, of these factors the subsea wellheads have been redesigned to handle drift off by large rigs with a heavy BOP. In addition, the drilling rigs now uses dynamic positioning (DP) instead of anchors, the wellheads then must handle more fatigue. The drilling rig have also become larger to operate on deep water and in extreme conditions. The required drilling speed has increased, and the rigs are competing to drill faster, resulting in larger rigs with dual derricks.

The rigs, particularly the ones operating on the NCS have been "winterized" to drill in the Barents Sea [23].

Wellheads, in turn, have become larger to handle more weight and fatigue. This has made cutting operations more difficult and demanding. However, the HC has already proven that it can cut these high fatigues wellheads in several operations.

8 From Rigbased to Rigless Approach

This chapter explains why operating companies are moving away from rig-based to rigless technology, and which type of vessels that are included in the different classes. The advantages of a rigless approach and how to implement a multiwell matrix in a campaign is illustrated.
Trends indicates that operators are moving away from the traditionally rigbased approach on well decommissioning and moving towards rigless operations. Replacing the high costs and availability issues of conventional rig-based abandonments with rigless technology will be a cost-effective solution for the operator and governments, which takes on a large portion of the decommissioning cost.
A well is traditionally abandoned using an SSR, since it is a reliable and capable of performing the entire P&A operation. Using SSR often lead to cost overruns because of high cost, limited availability, and unpredictability with P&A.

As a result, operating companies are looking for rigless technologies to decrease cost and reduce rig time. Rigless vessels can perform light weight (also called pre-P&A) operations and leave the heavier operations to SSRs. Heavier operations are casing and tubing removal. The rigless vessels offer considerable cost savings in daily rental rates and traveling time and use innovating technologies and better operational efficiencies.

The rigless class is divided into riserless light well intervention (RLWI) vessels and light construction vessels (LCV). These RLWI vessels can perform phases 0 and 3 of the P&A operation, while LCV is suitable for low complexity phase 3 well abandonment. The significant difference between SSR and RLWI is the well control equipment and how the vessels connect to the subsea well to allow fluid transport and intervention. The SSR uses a subsea BOP together with a workover riser for a high pressure well or a marine riser for a low pressure well, whereas RLWI vessels use a riserless system with wireline technology. Operation companies must choose the most cost-efficient solution to P&A their subsea wells depending based on the well's classification. Wells should be classified according to location, abandonment complexity and abandonment phase for reliable cost estimation in section 5.4 Plug and Abandonment Complexity.

The advantages of P&A operations are that these are generally not time critical, making it possible to perform it in a set of sub-operations and allows the well to be temporarily or partially plugged, if the well is monitored. Phase 0 can be completed months ahead of phase 1 and 2, then phase 3 can be completed one to two years later. This provides the operating company a flexibility in choosing the most cost-efficient solution for their future well abandonment. Although it is not a time critical operation, the operator often set a time window for the operation because of legal problems, such as expiry of their lease contract or vessel contracts.

8.1 Advantages with rigless abandonment

The rigless concept is based on a mono hull vessel and wireline technology, which can perform operations such as killing the well, punching the tubing, setting temporally plugs and removing the wellhead and connector. To perform in-hole subsea well operations without the use of a traditional SSR, the vessel needs a dynamic positioning system, derrick or tower with heave compensation to deploy equipment and enough size and capability to accommodate equipment and personnel required. Riserless technology will play an important role in reducing the cost of well abandonment and release rig time to perform the operators core activities, drilling and completing wells. To gain benefits of using a dedicated vessel to perform a sub-operation, multiple wells should be abandoned in a campaign approach. Since subsea wells are located at different locations around the seabed, and not located at a single point, i.e. a platform, then the rig or vessel must physically move from wellhead to wellhead (or template to template) to perform the necessary operations. This continuous relocation is time-consuming and significant time and thus costs can be saved by abandoning several adjacent subsea wells together in multiwell campaigns. However, RLWI vessels have shorter mobilization and traveling time than an SSR [24].

There are also logistical advantages when planning a multi-well campaign, because in a campaign performing a full P&A on each well before moving to the next it is not necessary. The subsea well decommissioning campaigns could be completed in batch operations where the drilling vessel finish one operation on each well, before moving to the next. Batch operations exploit the conveyer belt effect that reduce the overall cost for the P&A operations. Vessels will then perform one operation on each well, before moving on to the next. This allows the various vessels to optimize the operation it performs.

8.1.1 Multiwell Campaign Matrix

Maximizing the cost saving potential with rigless abandonment technologies and equipment, requires collaboration between operators and service companies.

Multi-field and multi-operator campaigns are built upon collaboration between the technology vendors, and experienced project management and flexible operators regarding the timeframe of the campaign [24].

Operating companies in the UK have been willing to perform multi-well campaigns with multiple operators and well operations. This approach takes advantages of economics of scale. A multi-operator campaign there will be reduces mobilization costs compared to a district or integrated campaign and an increases supply chain integration and development [24].

The campaign can be managed by one operator or a consortium of operators. It is often managed by a well project management team or marine contractor that commissioned the campaign.

The economical aspect of using designated vessels could be economical favourable when at least two wells can be combined. One well is not cost efficient because of large mobilization cost and traveling time to and from location for many vessels, while in a multiwell campaign these expenditures are shared amongst the number of wells [25].

There will be an increase in project coordination, management and logistics with several vessels involved in a multiwell campaign. However, the benefit of cost reduction in lower day rates and lower person on board (POB) can typically save 10% to 15% over an integrated multi-well campaign. It is important to include issues such as correlations, learning effects, unpredicted events and dependency between sub operations either inside a single well or between different wells.

Phase ↓ Complexity →	0 No work required	1 Simple Rigless	2 Complex Rigless	3 Simple Rigbased	4 Complex Rigbased
0 Preparatory work	**2**	**3**			
1 Reservoir Abandonment				**3**	**2**
2 Intermediate Abandonment				**5**	
3 Wellhead and Conductor removal		**5**			

Table 2 - Well complexity matrix of 2 wells with phases and complexity

To illustrate the multi-well campaign in Table 2. First, phase 0 could be performed by RLWI for the three wells needing preparatory work. Secondly, an SSR could performed phase 1 and 2 for all five wells and finally an LCV or RLWI could performed phase 3 for all five wells.

The selection of the other equipment, services and capabilities are aligned to the vessel selection. Since light vessels are preferred for parts of this operation, harsh weather must be considered as these vessels must stop work in harsh weather. Phase 3 of P&A campaigns should be restricted to late spring through early autumn as the weather window for this period is usually ideal. Although light vessels have weather restrictions, they can perform sub-operation in short weather windows; RLWI vessels can perform the following steps within a 24 hours window: presurvey, removal of net guard or tree cap, deployment of cutting tool, severance the wellhead 5 meters below seabed, retrieval of wellhead to deck and final survey before leaving site. All operations can be started, performed or stopped independent of the forgoing or next step. This makes the operation flexible and adaptable to short weather windows [26] [24].

8.2 Multiwell Phase 3 Campaign

During a multiwell phase 3 removal campaign, the largest cost is the drilling rig rental, which make moving toward vessel technology a key driver for rigless abandonment. Also, reducing to a vessel will further reduce costs because of less maintenance, personnel and mobilization costs.

The vessel selection must be suitable for the operation requirements. The vessel will need a heave compensation hoisting system capable of a minimum 80-ton capacity to convey bottom hole assembly and connector, and then recover both with the wellhead attached. A typically subsea construction vessel with a suitable crane along with an available deck space for horizontal tool spring deployment can perform this operation. This gives the operators a flexibility in vessel selection [24].

Remotely operation vehicles (ROVs) are critical equipment for subsea operations. These vehicles provide visual communication with the wellsite and manipulates equipment with two manipulator arms. This allows tools to be manipulated, guided and actuated from a remote-control cabin at the surface vessel via umbilical-conveyed electro-hydraulic and pneumatic service.

9 Wellhead Cutting Technology

The final part of the well abandonment process is cutting and removal of the wellhead and the conductor. The cut depth, usually from 3 to 5 meter below seabed, is defined by the government in the operating country. Mechanical cutting and AWJC will be described in this chapter to show the differences between the two technologies.

9.1 Abrasive Water Jet Cutting

The development of AWJC technology for wellhead cutting began in 2001 on the NCS. The first test cuts came on Ekofisk in 2002, and the first commercial conductor cut on Frigg in 2003 [27].

This technology is an innovative solution to the traditional mechanical cutting. Mechanical cutting is performed on drill pipe from a rig, while AWJC allows for cutting from a vessel. Thus, AWJC technology can be deployed using a standalone deployment system to remove the wellhead below the seabed. The AWJC tool is used to cut through multiple casing stings and conductors from 7-inch to 36-inch, regardless of the number of casings, conductor weight or cement presence in the well annulus. The vessel or rig preforming the cut should at least have a lifting capacity of 100 tons to lift the wellhead on board [28] [12].

9.1.1 Abrasive Water Jet Cutting Technology

Abrasive water jet cutting involves combining high-pressure water and abrasive material to provide a method to sever through metals, plastics, wood and many other materials with high accuracy. This technology needs a large amount of water which is typically supplied with water tanks or filtered seawater offshore for an uninterrupted flow. The water is fed into the tank of a high-pressure pump unit where it is pumped with a pressure in the region of 5000 to 15,000 psi and a flow rate of 100 to 200 litres per minute. The pressurized water enters the abrasive mixing unit where the abrasive material is entrained in the seawater. As per the figure, the water flow supplied by the high-pressure pump is restricted to divert approximately 10% of the flow into an abrasive mixing unit. Then, the flow is filtered back into the water supply to create the high-pressure abrasive water medium. This medium is then delivered to the cutting tool. Entraining the abrasive material in water rather than air is the mitigates sparks during cutting, which is key for oil and gas applications in zoned environments [28].

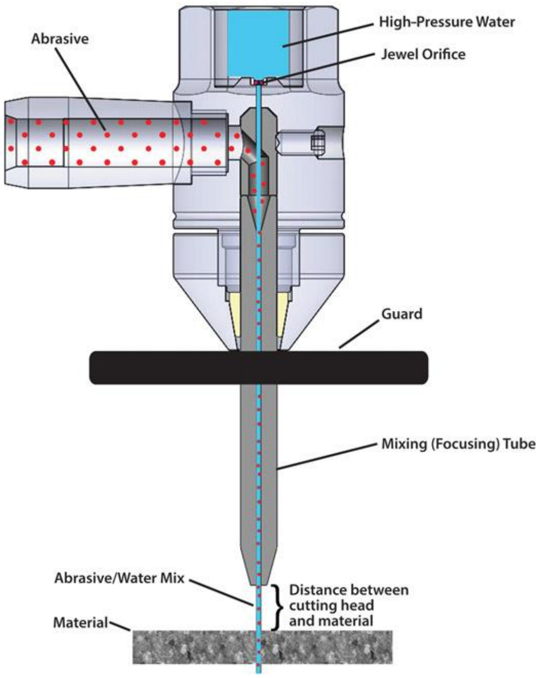

Figure 16 - Illustration of AWJC technology *[103]*

The cutting tool assembly contains a wellhead connector, manipulator, head with nozzle and centralizers. The tool is connected to the pumping spread through umbilical, which is also used to land the tool onto the wellhead. The nozzle inner diameter is sized to create a high-pressure jet; a back pressure is created from the reduced nozzle size that allows the pump to build pressure and potential energy. The abrasive water material is accelerated across the cutting nozzle by up to 80% to have the cutting power to sever up to six-inches of steel.

Garnet, a natural mineral with high hardness properties, is typically used for the multi-string cutting application for well abandonment. The key is achieving a balance between cutting performance and wear rates on the components within the cutting system in which the density and hardness are the two most important parameters. For example, a high garnet content within the slurry mixture will result in improved cutting duration but will enhance wear rates, whereas a low garnet content will result in increased cutting duration and reduced wear. To optimize the operation, clarifying the casing characteristics, such as well thickness, eccentricity and cemented annulus is beneficial during the planning phase to choose the optimal nozzle size, cutting head rotation speed and pressure across the nozzle [18].

Figure 17 - Cut wellhead with AWJC tool still inside, from wellhead cutting campaign *[83]*

9.2 Mechanical Cutting Hercules Cutter

In this section, mechanical cutting technology, the HC, is explained. The HC will be the main component of the subsea wellhead terminator assembly that is under development in BHGE.

The cutter is designed to cut single or multiple layers of casing in one operation. It is operated on drillpipe and is equipped with three knives for quickly and easy cutting through the casing. The string of drill pipe transmits drilling fluid via mud pumps and torque from the top drive to the HC. The HC is run internally within the riser and BOP through the wellhead to the section or required depth to where it should cut the casing. Drilling fluid (mud) pressure acting against a piston is used to hydraulically operate the HC.

The necessary pressure differential is established by the flow rate, through the drilling or workover fluid through the indicator nozzle. This pressure is controlled by the driller via the mud pumps. There is normally a field service engineer from BHGE on the drill floor assisting when this tool is in operation. The nozzle size can be adjusted to produce enough pressure differential depending on the fluid pump flow rate available from the rig.

Each rig has different equipment onboard and BHGE personnel must choose the right nozzle based on a set of different factors. The nozzle chosen depends on the drillpipe used, the mud pumps available, the mud specifications and other equipment running simultaneously.

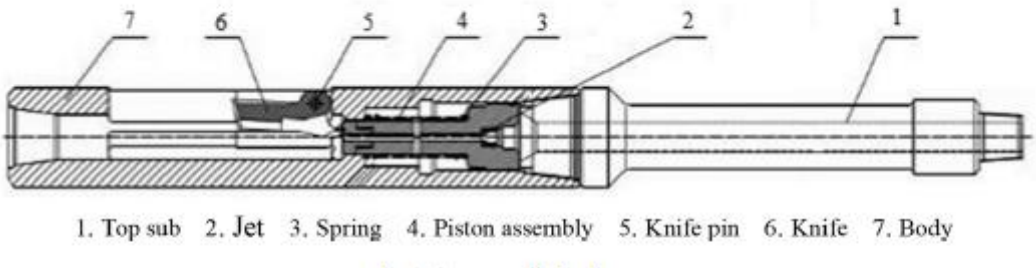

Figure 18 - Hercules Cutter component overview. From internal BHGE documents

For instance, BHGE now does combines runs. Here, BHGE pull the bore protector (wear bushing) and cut the wellhead simultaneously. Then, the HC operator must know the internal diameter of the other equipment and pipes to choose the correct nozzle. This is possible with the cooperation of Vetco Grey AS and Baker Fishing services. This collaboration only works, because of BHGE’s expanded service portfolio. When enough pressure differential is achieved, the piston will move against the compression spring and contact the knife heel moving the knives outward into cutting position.

The knives are dressed with carbine superalloy or metal muncher inserts, making them harder than the casing wall. The continued piston movement forces the knives to pivot about the knife pins. The knives expand outwards and reach the inner wall of the casing that will be cut. When the knives are near full expansion the indicator contacts the indicator stop and further piston movement causes a separation between the piston and the indicator [29].


Figure 19 - HC Knife with Superalloy and metal muncher inserts, private photo

At this point, the drilling fluid begins to flow freely through this separation which results in a reduced pressure differential that signals the operator that the knives have come to a fully extended position. The tool is then rotated by the top drive at the required speed. This rotation speed is adjusted to the casing being cut. The operator can follow the pressure to know how far out the knives are, and when the pressure suddenly drops, he or she will know they have made a successful cut of the first layer of casing.

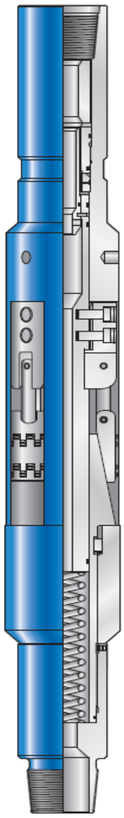

Figure 20 - HC

On subsea operations performed by an SSR, the tool is combined with a marine swivel that ensures the cutting assembly remains in the same position during the entire cutting operation. The marine swivel can make vertical movements and reposition the cutter. The HC can be operated with BHGE's UWRS. This system enables BHGE to be able to cut and retrieve a subsea wellhead in one trip. The tool can be used on wellheads from any manufacture. For the subsea wellhead terminator, the HC will be the component that performs the cutting [29].

10 P&A Challenges

There are many challenges related to P&A, including in economics, technology, planning and regulations. This section provides insights into some of these challenges and identifies the main challenges related to P&A operations.

10.1 Economic Challenges

10.1.1 Net present Value

When considering cash flows on a long-time horizon, it is important to include net present value (NPV) considerations. Net present value is the difference between the present cash flow inflows and the present value of cash outflows over time. This difference is used to evaluate whether an investment or project is profitable. Thus, NPV it will be either a profit or a net loss [30].

$$NPV = \sum_{t=0}^{N} \frac{R_t}{(1+i)^t}$$

Figure 21 - Net Present Value

According to the NPV equation an inflow today is worth more than the same inflow in the future. The same principle applies to costs or outflow. An outflow today is larger than the same outflow in the future, since it cannot grow. Operating companies wants to postpone P&A operations further into the future to gain the benefits of better technology and NPV. A social economic condition is also associated with P&A as the operators can tax deduct all P&A investments. In the same way as the Norwegian state takes 78% of the petroleum revenue in tax, it must also bear an equally large share of cost in investments such as P&A. Therefore, minimizing cost is in everyone’s interest [31].

Operators are responsible for executing the P&A operation safely with regards to QHSE. A good term to describe the operator objective is as low as reasonably practicable. Which means reducing the risk as far as reasonably practical to a point where reducing the risk further will grossly disproportionate the benefits generated [32].

One of the challenges related to the economic aspects is the uncertainty of the operation's duration, which is the main cost drive. There will always be uncertainty with P&A, as no operation is the same as another. This is because of no wells being alike, there will always be differences in geographical formations, well schematics, equipment and technology used in the P&A operation. This makes it hard for the operator to estimate the total cost of the operation. Operators must spread the P&A operations over time to be able to handle the negative cash flow from decommissioning. They are also obliged to start the P&A shortly after a field has reached the end of its lifespan, according local and national laws and regulations.

10.2 Technology

Technology is always improving and developing for the better, making P&A operations safer and faster. These positive abilities create challenges because operators wants to wait to P&A to let other operators develop new technology, since operators normally do not like to take risks with new technology and equipment. Thus, the technology in P&A, as well as other segments of oil and gas operations have slower technology development than it could achieve.


Figure 22 - Photo of UWRS and cut wellhead. Source BHGE

Transferring sub-operations to RLWI instead of rigs will release rig time for drilling and completing of new wells, as well as reducing the total cost of P&A. Equinor claims that there is at least a 30% cost savings in technology development where rigless P&A operations replace rig-based. For rigless technology to improve, it must be used, implying P&A operations must be spread over time, so the service companies have time to develop technology and have a balanced demand [33].

10.3 Planning

Planning P&A operations is key to reducing the cost of well decommissioning. This subsection examines the challenges related to planning well decommission operations, determines how the challenges could be met and explains the current state of the industry.

10.3.1 Information

Many parties are involved during a well's life cycle, from planning, drilling, completion, maintenance, intervention and P&A. Recording the information on the well design, past work, well performance and reservoir conditions throughout the well's life would make planning P&A easier. Many operators are experiencing challenges in planning of P&A because data is not collected and shared. This limitation is especially true for wells in which the ownership has been transferred from one operator company to another. Detailed pre-planning is crucial, since cost escalation due to unforeseen events can be a challenge that prevents cost-effective solutions. There are several reasons way the data is not centralized. The data collected differ in quality, in amount collected and in format. For old wells, the data is often lacking and in poor quality due to earlier operators and industry not understanding the value of the data. In addition, the data is collected in different formats and stored different places. Furthermore, information is still stored in traditional paper files and transforming the relevant information to digital files demands resources.

To plan P&A operations efficiently, an operator needs to know as much information about the well as possible. The challenge lays in obtaining the relevant information to plan successfully. Information about well status and type, casing program, completion equipment, status cement and number of inflows are important efficiently plan P&A operations. Well schematics, which should be easily available, could be difficult to obtain in some cases, and this information is critical to planning the operation in a safe and efficient way. Well schematic data is now stored in drilling reports and well reports, so to obtain this information, one needs to search the well report. However, these reports have different formats and contain various data. Thus, when an operator must plan P&A operations for several wells (e.g. for a field), collecting the relevant data may be time consuming.

According to NORSOK D-010 the following parameters should be included in the design basis for the well barrier design and abandonment program: [8]

- Well configuration (original and present) including depths and specification of formations that are sources of inflow, casing strings, casing cement, wellbores and sidetracks.
- Stratigraphic sequence of each wellbore showing reservoir(s) and information about their current and future production potential, with reservoir fluids and pressures (initial, current and an eternal perspective)
- Logs, data and information from cementing operations.
- Formations with suitable WBE properties (e.g., strength, impermeability, absence of fractures and faulting).
- Specific well conditions such as scale build up, casing wear, collapsed casing, fill, H_2S, CO_2, hydrates, or benzene.

10.3.2 Operator Collaboration

There are significant economic advantages for operators to collaborate with P&A. According to Marathon Oil, operators could reduce P&A cost for subsea wells by 30% to 40 % if they are willing to take a fully collaborative approach with rival producers. Some of the advantages is economics of scale, knowledge sharing and increased learning curves and experience.
Operators can perform P&A on wells located close to each other and save mobilization, demobilization and transit time as well as increase the learning effect on the crew working on the rig or vessel. At present, limited co-operation has occurred in the North Sea and in the Gulf of Mexico, where contractors such as Helix Well Operations, have brought together operators in joint subsea P&A campaigns [34].

A few of the operators at the front of large decommissioning programs are now considering collaboration with other companies. These operators realize collaboration is much more efficient because contractors can plan their work in the most efficient way regardless of ownership.

10.3.3 Rushmore Abandonment Performance review

Since 2008, operators have been sharing data from their P&A through the abandonment performance review (APR). They use this data to plan and budget their well operations, as well as measuring performance improvements. The 17 operators in APR will gain intelligence and data from preciously abandon wells and see current best practice from other operating companies. Sharing data between competitor's could result in significant cost reduction on future P&A operations [35].

The APR is designed to give operators answers to the following questions:

- Am I "overengineering" my design?
- Are others using more effective techniques?
- What failures are other operators experiencing?
- Which auditable data can I use to calculate future abandonment liabilities?
- What savings are typically achieved in abandonment campaigns?
- Which technology trials are appropriate?
- What lessons have other operators learned?
- How does differences in regulations effect cost and time outputs?

To obtain answers to the question, the operator is required to give the following information about their performed P&A operations;

- Well details: (i.e., name, location and technical description)
- Fluids (e.g., H_2S, CO_2, LSA, HPHT, Wellhead type)
- Work done: (e.g., cutting, PWC, milling, retrieval of casing and barrier set)
- Time duration: (e.g., rig and rigless operations with NPT and WOW Cost)
- Before and after well schematic diagrams
- Description of well prior to abandonment and work scope
- Details in timing per phase
- Complexity of the well

10.3.4 DISKOS 2.0

Despite the planning challenges, there is work being performed in this segment, the Norwegian Petroleum Directorate (NPD) currently has a competitive bidding process on Diskos 2.0, which will be a successor to the current version of Diskos that holds information on the following [36]:

- Reference data
- Seismic
- Well
- Production

Diskos envisions collecting and centralizing all data from exploration and production wells on the NCS, making the data digital and easily accessible. Diskos 2.0 is being designed to handle the increased amount of data being collected; the data collected in the oil and gas industry has skyrocketed in the last two to three years, see figure below. The new version of Diskos will allow companies to safely and conveniently trade confidential data. The planned release date for Diskos 2.0 is autumn 2020 [37].

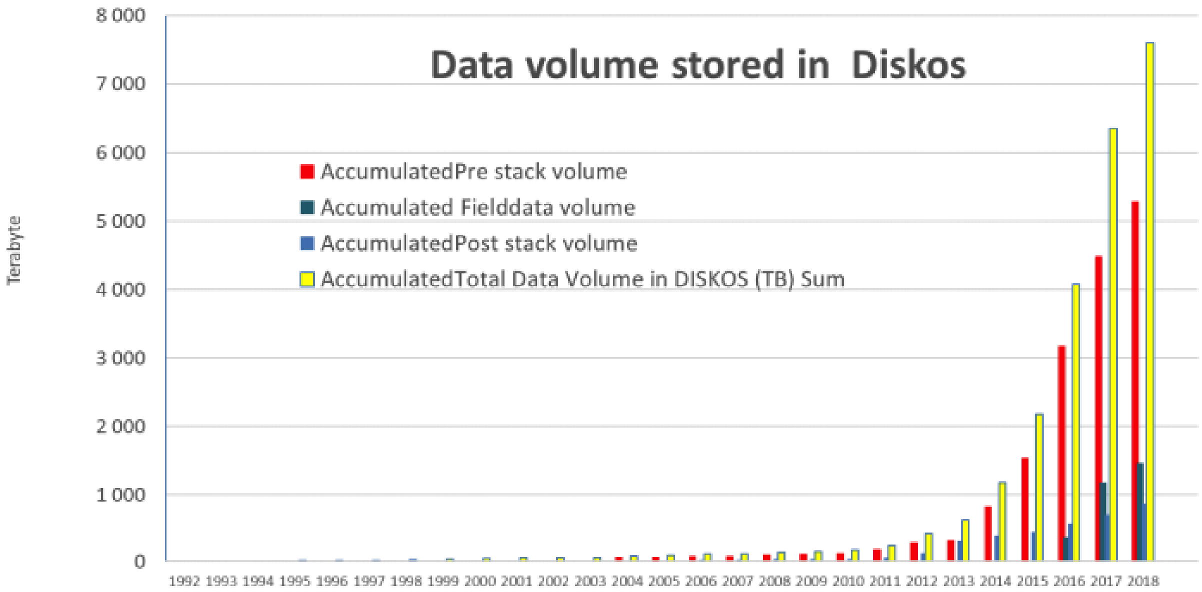

Figure 23 - Data in Diskos, showing the increase in stored data on NCS

10.3.5 Well Design

When operators plan their new fields or wells, they devote little to no attention to the P&A aspect. Designing a well with P&A in focus, means choosing technology and downhole equipment that is easy to retrieve, and make the P&A operation safer and more efficient. As mentioned, data collecting in the installation phase could make future P&A operations easier. Since well decommissioning is almost 50% of the total decommissioning cost, planning for P&A in the design phase could increase the overall revenue of the well. If the future has more quality data availability, planning for P&A operations will be easier and the decision maker will be able to make more realistic budgets and choose the most suitable drilling service and technology to safely and efficient perform the operation.

10.4 Well Regulations

There is currently no international standard for well decommissioning. The quality, robustness and philosophy of well abandonment and decommissioning guidelines vary significantly by country, so well design vary by location. In addition, new well P&A technologies are typically not covered within existing guidelines (e.g., rigless technology and chemical thermite plugging) [38]. Laws and regulations need to be adjusted to accommodate for new technology being developed.

Regulations should ensure that well abandonment operations provide long-term integrity of the well P&A. The regulations thus need to specify how long the P&A well integrity should hold. Not having clear guidelines emphasizes the regulating instance should carefully review, and subsequently approve, any P&A plans to ensure they are fit to achieve long-term well integrity.

10.4.1 Well to Well Approach

The challenges above are somewhat related to or a consequence of the uniqueness of each well. Because wells are unique, the scope of work required for a safe and efficient P&A operation, while staying within regulations, vary. Well conditions, such as well depth, formation, reservoir, pressure, temperature and the environment, differ greatly. Therefore, installed equipment also differs to accommodate different conditions. There are alterations in installed equipment because of different architecture on the different fields. Installed equipment varies by supplier used. There are often many suppliers involved in the equipment for one wellbore.

Variations in installed equipment could make pulling casing and downhole equipment more difficult. Thus, a certain type of technology may be required to retrieve the equipment. Some of this equipment, especially old equipment, could only be operated from a rig, making the shift to rigless even more challenging. Wells are also unique due to damages and unforeseen events in the well's lifetime, such as dropped objects and high sand levels. Furthermore, the cement job can create variations in wells if the cementing was poorly completed or has deteriorated over time through chemical exposure, mechanical loads, chemical exposure, creep or shrinkage [39]. These are just some of the conditions that make the wellbore unique.

10.5 Waiting on weather

Waiting on weather (WOW) is a major cost in offshore operation and is the most common environmental disruptions impairing well services. Thus, WOW is a substantial challenge when planning well decommissioning operations [40].

Figure 24 - Illustration of harsh weather in the North Sea. Source UiS [43]

The weather conditions on the NCS can be harsh and cause several hours of non-productive time (NPT) because RLWI vessels are more sensitive to weather than an SSR since they are more sensitive to waves heights, periods and directions. Thus, are differences in how the vessel react to heave, pitch and roll. RLWI vessels uses DP to align with the wave direction to reduce the wave frequency motion; SSR is usually anchored during operation, but DP is also an alternative for rigs. The average WOW is usually set by operators at 10% to 15% of standard operation time, but during the harsh winter, WOW can increase to around 50% of operation time [19].

To decide whether to continue an operation, the operators check the weather forecast; for RLWI vessels, two independent weather suppliers are used. Real-time weather data is collected from a weather station onboard.

11 One-stop shop

The recent trend in oil and gas service is the growth of the largest service companies, like BHGE, Haliburton and Schlumberger, through mergers and acquisitions. These big service companies are absorbing smaller support entities, delivery systems and manufacturers of equipment used in oil and gas operations. By doing so, they are suppressing some of the competition and strengthening their own positions in the market [41].

Earlier operators wanted to have full control over project deliverables to efficiently run the operation. Now, operators have realized that efficiency occurs through specialization. In addition, following the deliveries and operations is resource demanding.

Operators have been recently giving larger contracts to oilfield service companies and are looking for companies that can take on large contracts where risk is shared between both parties. This strategy requires fewer procurement and organizational resources within the operator's organization, but it transfers this responsibility to the service provider. The service provider must then expand its organization to counter this increased scope. As a result, the service companies are expanding by investing in and buying other smaller service providers [42].

11.1 Introduction to Baker Hughes, a GE Company

Baker Hughes became Baker Hughes a GE Company (BHGE) in 2017 when industrial giant GE, bought 62,5% of the shares.

Figure 25 - BHGE Logo

Making BHGE the second largest oil field service company ahead of Haliburton and behind Schlumberger. In November 2018, GE sold four billion worth of Baker Hughes shares, and as of March 2019, GE holds 50.4% of the shares [43] [44].

Baker Hughes, a GE Company, is a combination of many companies that have developed and introduced technology to serve the petroleum industry [45] [46].

During its history, BHGE has acquired and assimilated numerous oilfield pioneers: Brown Oil Tools, CTC, EDECO, and Elder Oil Tools (completions); Milchem and Newpark (drilling fluids); EXLOG (mud logging); Eastman Christensen and Drilex (directional drilling and diamond drill bits); Teleco (measurement while drilling); Tri-State and Wilson (fishing tools and services); Aquaness, Chemlink and Petrolite (specialty chemicals), Western Atlas (seismic exploration, well logging) and BJ Services Company (pressure pumping). [47]

Oilfield equipment is often complex and require considerable resources. Thus, the best solution for a company to expand its services is to acquire a supplier in the sector because one just does not need the technology to perform the operation, one also must have the knowledge of the operation and experienced personnel. Therefore, BHGE has acquired several service companies to expand its services [48].

11.2 BHGE a One-stop Shop Service Company

The introduction to this section and the brief history of BHGE highlights that the company has been expanding since its beginning. This constant expansion has now allowed BHGE to work toward becoming a one-stop shop for oil and gas services. The merge of Baker Hughes and GE have make the company more robust and positioned to take on large contracts [49].

A one-stop shop is a contractor that takes on the entire scope of large contracts. Then, the supplier is the only relationship the operator must have. If BHGE is aiming to become a one-stop shop supplier, the operator could place a contract with BHGE for an entire project, and BHGE would manage, plan, coordinate and execute that project.

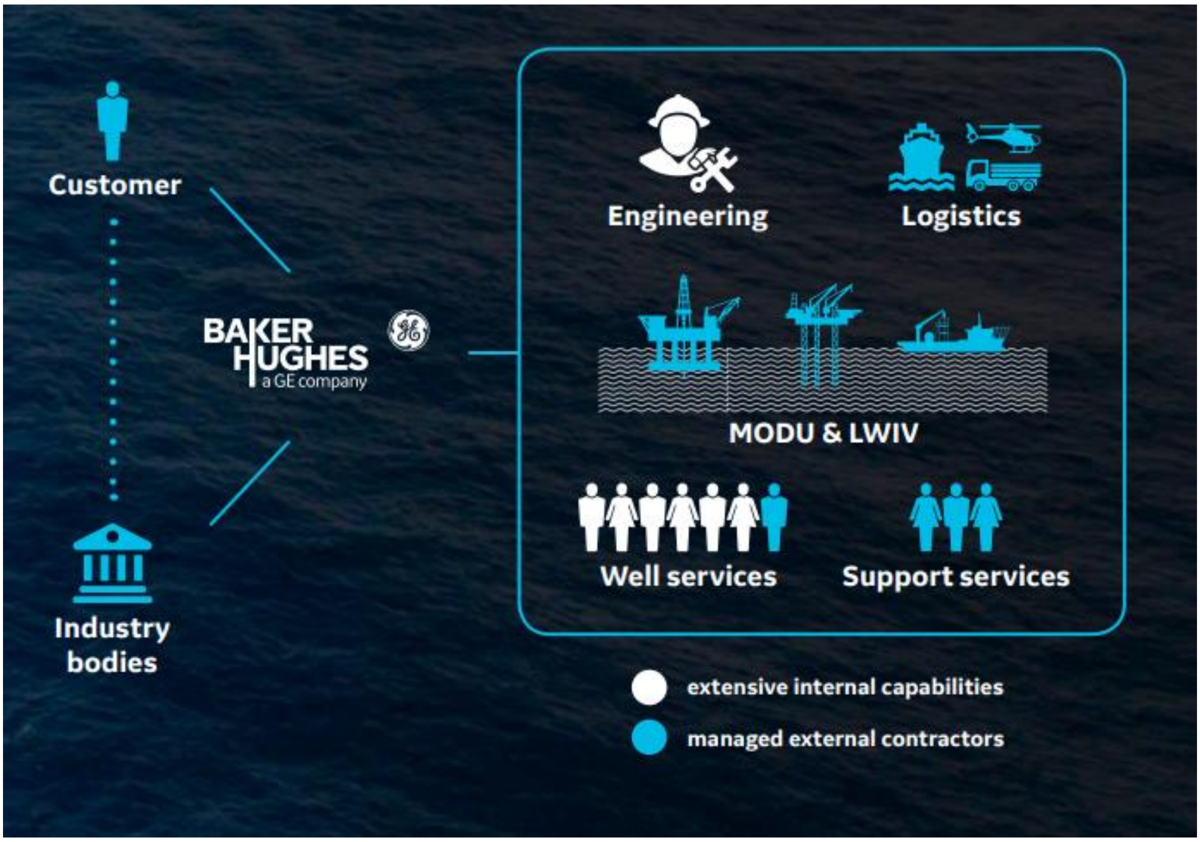

Figure 26 - BHGE One-stop shop

In the figure, BHGE is displayed in white and external contractors are in blue. Although BHGE does not have the capabilities to internally manage the logistics internally, project managers handle the coordination for the equipment and supplies is needed for the operation. Logistics is challenging in offshore operations as there are many parties involved [50].

The SSR and vessel will be rented from an offshore drilling contractor, and BHGE must choose the most suitable type for the operation considering commercial and operational aspects. The commercial model for the entire contract scope provides closer collaboration with risk-sharing between contractor and supplier, including shared downsides and upsides. This risk-sharing encourages collaboration since both parties are dependent on the project's overall execution and delivery. In these contracts, the project must be executed by the best technology, resulting in some well services being assigned to other contractors. Engineers in BHGE are responsible for finding the best technology for the different operations.

11.3 Subsea Wellhead Terminator Contributing to the BHGE One-Stop Shop

The subsea wellhead terminator could strengthen BHGE's position to manage the entire scope of contracts for well abandonment. However, BHGE must choose the best solution all parties; thus, phase 3 will be rigless. Currently, BHGE does not possess competing technology for rigless subsea wellhead removal. To fill the gap, BHGE outsources this aspect of the contract to third party suppliers. The BHGE website lists two case studies on large well abandonment contracts where BHGE was the main contractor. These case studies describe two of BHGE's successful well abandonment operations: one in the Gulf of Thailand [51]and one in the North Sea. In both case studies, BHGE uses a third-party supplier with an AWJC to remove the subsea wellheads [52] [53] [54].

These examples indicate that BHGE is missing competitive solutions for rigless subsea wellhead removal and therefore uses an external supplier. In the worst case, this outsourcing could result in BHGE losing a contract. When part of the scope must be outsourced to an external contractor, some of the margins will be lost. Having a larger portfolio of wellbore service tools would increase BHGE's chances of winning contracts. Offering complete services it requires a broad portfolio of service tools since many operations require special tools and customized solutions [55].

The subsea wellhead terminator will therefore strengthen BHGE and enable the company to perform more of the well abandonment scope using in-house solutions. This change could increase revenue and provide a better total delivery. The new equipment will also enable BHGE to complete phase 3 subsea wellhead removal campaigns. Competitors have already completed serval phase 3 campaigns.

12 Competitor analysis

This section examines BHGE's main competitors in rigless P&A. Analyzing competitors in the market establishes awareness of the competition the subsea wellhead terminator will encounter. In this research, we were not able to examine all possible BHGE competitors, but we believe the main competitors that could compete on phase 3 well decommissioning and one-shop stop contracts are addressed.

Schlumberger, Halliburton and TechnipFMC are BHGE's main competitors regarding one-stop shop solutions. Weatherford, TechnipFMC and Oceaneering are the largest competitors on phase 3 wellhead removal.

The table below compares the different companies: employees, revenue, P&A technology, experience, as well as weather the company has in-house vessels that can perform P&A operations. Revenue and number of employees are included to show the companies capability of acquiring or developing new technology and their ability to take on risk. The large oil companies tend to acquirer or merge with smaller companies to own as much as their value chain as possible. This strategy gives them the opportunity to offer one-stop shop service contracts to operators.

Company	Revenue ($ Billion)	Employees	Drill pipe deployed cutting	Offline from rig	Rigless P&A	Vessels	Wellhead Removal Experience
Schlumberger	32,8	100000					> 1000
Halliburton	24	60000					< 100
TechnipFMC	12,6	37000					< 1000
Baker Hughes GE	22,9	66000					> 1000
Oceaneering	1,9	9500					< 1000
Weatherford	5,7	25000					> 1000

Table 3 - Competitor Analysis

Inside Portfolio

Partner with others

Gap in portfolio

When looking at the table, BHGE is competitive regarding revenue, employees, drillpipe deployed cutting and wellhead removal experience. The gaps in BHGE's portfolio are rigless P&A. By successfully implementing its subsea wellhead terminator, the company can reduce their portfolio gap.
The competitor analysis indicates Schlumberger has the best resources. This company can offer all parts of the P&A well services. Schlumberger does not own all parts, but though its subsea alliance with Helix Energy, it is able to perform rigless P&A.

12.1.1 Schlumberger

Schlumberger is the world's largest oil and gas service company with over 100,000 employees and a revenue of $32.8 billion in 2018. Schlumberger and Helix Energy made a subsea service alliance in 2017 to provide RLWI solutions to all customers worldwide. Helix owns a range of well abandonment tools, including an Axe Wellhead Cutting System, which is an AWJC technology. With this system in their portfolio, Schlumberger can perform phase 3 wellhead removal rigless. However, the company's most used P&A system is still their Comprehensive P&A system, which is a rig-based one trip abandonment system [56] [57].

Through the company's subsea alliance Schlumberger has a small vessel fleet with ROVs included, that can perform rigless P&A operations within the alliance. This fleet includes two RLWI vessels and some LCV vessels [58].
The subsea service alliance's goal is to eliminate the need for rigs in abandonment services. Schlumberger's research and development department are seeking ways to perform P&A with only vessels [59] [60] [61].

12.1.2 Halliburton

Halliburton is one of the world's leading oil service companies with over 60,000 employees and a revenue of $24 billion in 2018. Halliburton does not own a wellhead removal system but is still able to offer one-shop stop contracts because the company hires a third-party supplier to perform the wellhead removal. Halliburton has explosive and chemical cutters, but these are made for smaller casings and stuck drill pipes. The company specialize in cement logging and setting the well barrier in the P&A operation. There is no clear indication whether Halliburton is making the transition to the rigless P&A marked in the near future. With its revenue and size, the company can acquire or merge with a company like Schlumberger did with Helix Energy [62] [63].

12.1.3 TechnipFMC

Technip FMC is one of the largest service providers, with 35,000 employees and a revenue of $14.56 Billion in 2018. In February 2018, TechnipFMC acquired a 51% stake in island offshore and created a new company called TechnipFMC and Island offshore subsea (TIOS) company. This new company will perform all vessel-based light well intervention services, such as P&A. Island Offshore provides RLWI project management and engineering services for P&A, riserless coiled tubing and well completion services. In addition, Island Offshore’s vessels are design for subsea P&A operations, indicating that TechnipFMC is entering the competition for a rigless P&A marked. With a large vessel fleet and several ROVs in its portfolio, TIOS is taking an offensive position in the rigless P&A market [64] [65] [66].

12.1.4 Oceaneering

Oceaneering is a small service company on a global scale but is a specialist in rigless P&A operations. The company has around 9500 employees, and its revenue was $1.9 billion in 2018. Oceaneering acquired Norse Cutting & Abandonment AS in 2011 to perform rigless P&A operations with AWJC technology [67]. In 2015, the company started performing rigless P&A and have completed over 120 wells. This experience has given the company a field proven technology, which is great in a conservative oil and gas industry. The operating companies want to anticipate time and cost ahead of operation, so Oceaneering’s business case provides cost efficient P&A using vessels instead of rigs, and the company offers lump-sum solutions per well to allow the operator companies to determine their expenditures. Oceaneering also performs an annular multi-client cutting campaign in which the participating operator companies benefit from sharing cost in several areas such as mobilization, fuel, transit, equipment and personnel. Within its portfolio Oceaneering has vessels and ROVs to perform rigless P&A campaigns [68] [67].

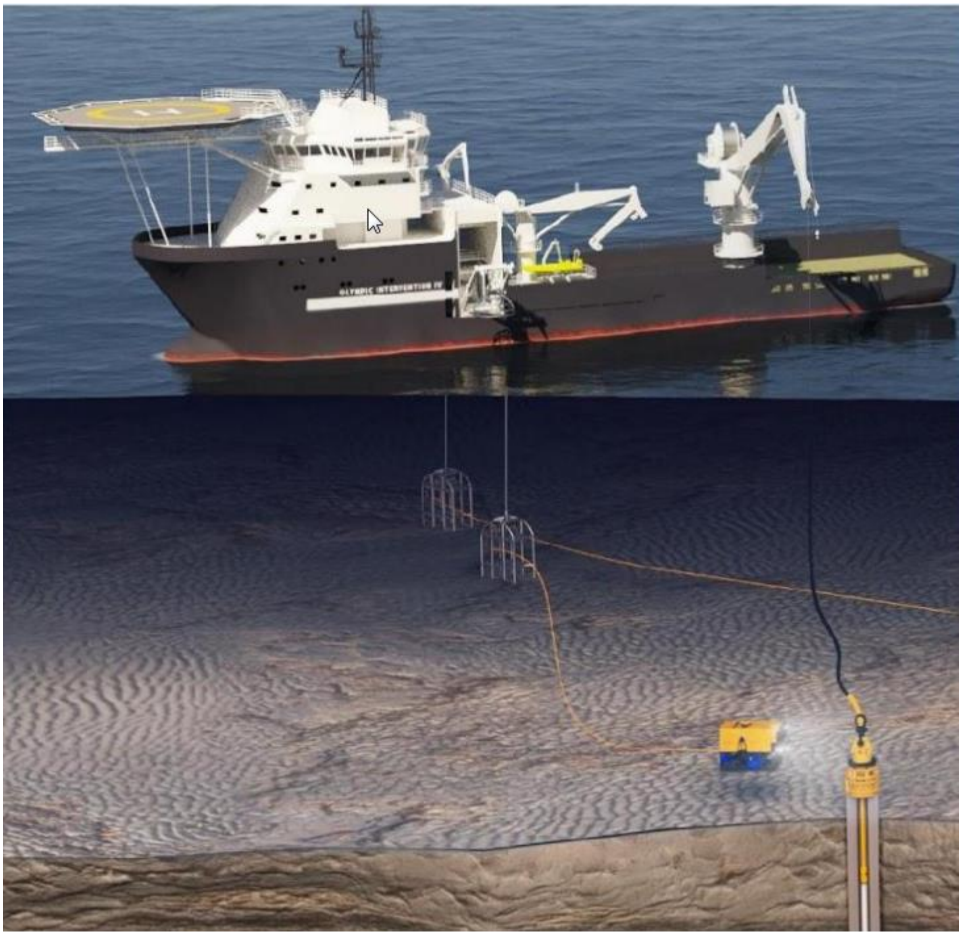

Figure 27 - Oceaneering using vessel deployed AWJC.

12.1.5 Weatherford

Weatherford is a well-known service company with 25,000 employees and a revenue of $5.7 Billion in 2018. The company's portfolio includes a full rig-based P&A from pre-job to final abandonment. Weatherford uses mechanical cutting technology as its main solution for wellhead removal. This cutter is similar to BHGE's HC. Therefore, if BHGE's HC can be transformed into a rigless wellhead cutter, Weatherford can do the same and reverse-engineer their own mechanical cutter to rigless. Weatherford and Proserv have an alliance which gives them the opportunity to use AWJC technology to perform rigless wellhead removal [69].

Whether Weatherford will take an active role in the future P&A marked is not clear, but the company has the resources and technology to tender for P&A campaigns using a third-party supplier [70] [71].

12.2 Positioning for Future P&A Market

Most BHGE competitors will clearly participate in the future rigless P&A market. Some, such as Schlumberger, are ahead of BHGE regarding equipment and tools to perform large P&A contracts for well decommissioning. Weatherford and BHGE are on the same level, and Halliburton is behind on well decommissioning. Oceaneering and TechnipFMC do not focus on one-stop shop contract for well decommissioning as they have large technology gaps, like cementing and drillings fluid, in their portfolios.

More well abandonment technologies will eventually be transferred to vessels, but there are still many innovations needed to achieve completely rigless P&A. All the competitors offering rigless well abandonment today use AWJC technology from different suppliers.

12.3 Competitor Comparison Analysis

To evaluate the competition for the subsea wellhead terminator, we compered BHGE with competitors on NCS. After research and discussion in the project team, Oceaneering was determined a suitable candidate for comparison since the company has enough available data on phase 3 subsea wellhead removal. Oceaneering has completed several wellhead removal campaigns on the NCS, delivering the entire work scope for the customer on phase 3 well decommissioning [72].

In this thesis, documented cutting time of both Oceaneering's AWJC tool and BHGE's HC tool are compared and analysed. There are some obvious flaws with the comparison, since the two tools have major differences. The main difference is that AWJC is a vessel operated tool, and HC is a rig-based tool operated on drillpipe. Compering a rig-based operation with a vessel operation is not ideal.

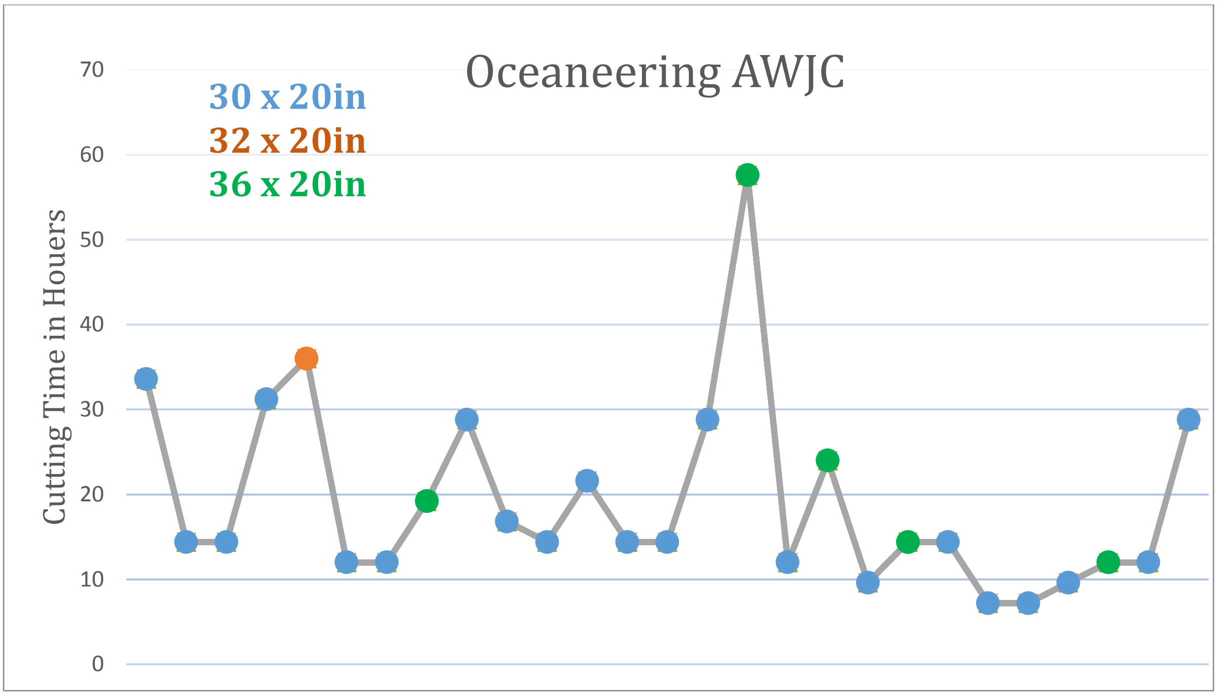

Table 4 - Cutting times for AWJC. Source: Case study Oceaneering

The table shows cutting times for Oceaneering's AWJC tool that is collected from two case studies from Oceaneering's website. Cutting times is converted from days to hours. In this thesis we made several assumptions to successfully compare the cutting times with the HC since data collected from the HC is from cutting operations done on 30 x 20-inch casing and 36 x 20-inch casing, while Oceaneering's cutting data is on several different casing sizes because the AWJC can cut more layers.

For the comparison, we assumed that a cutting operation for a 30-inch or 30 x 20 x 13 $^{3/8}$-inch conductor is the same as 30 x 20-inch to compare all cuts. Although cutting a 30-inch conductor takes less time than cutting a 30 x 20 x 13 $^{3/8}$-inch, we estimate that the indifferences will balance each other and display the average. All the cutting times thus provided an average range of cutting times for the AWJC [73] [74].

Table 5 indicates cutting time in hours from operations where the HC tool has been used as a part of the UWRS assembly. The data on wellhead removal for exploration drilling was gathered from BHGE operations. We assumed that the subsea wellhead terminator will have longer cutting times than a rig-based HC tool since from a rig the whole rotating momentum of the drill pipe string would create additional force that prevents the cutter from stalling. Calculations were performed to ensure that the subsea wellhead terminator had enough pressure and rotational force to perform the cut, but the preservation of the drill pipe string's angular momentum complicated the calculations. The project's onshore test anticipates finding operational performance differences between the rig-based HC tool and the subsea wellhead terminator.

Cutting times provided on the HC only include the cutting of the casing and not retrieving the wellhead because BHGE cannot influence the drilling company's tripping efficiency. Thus, BHGE has not recorded tripping times on the different cutting operations.

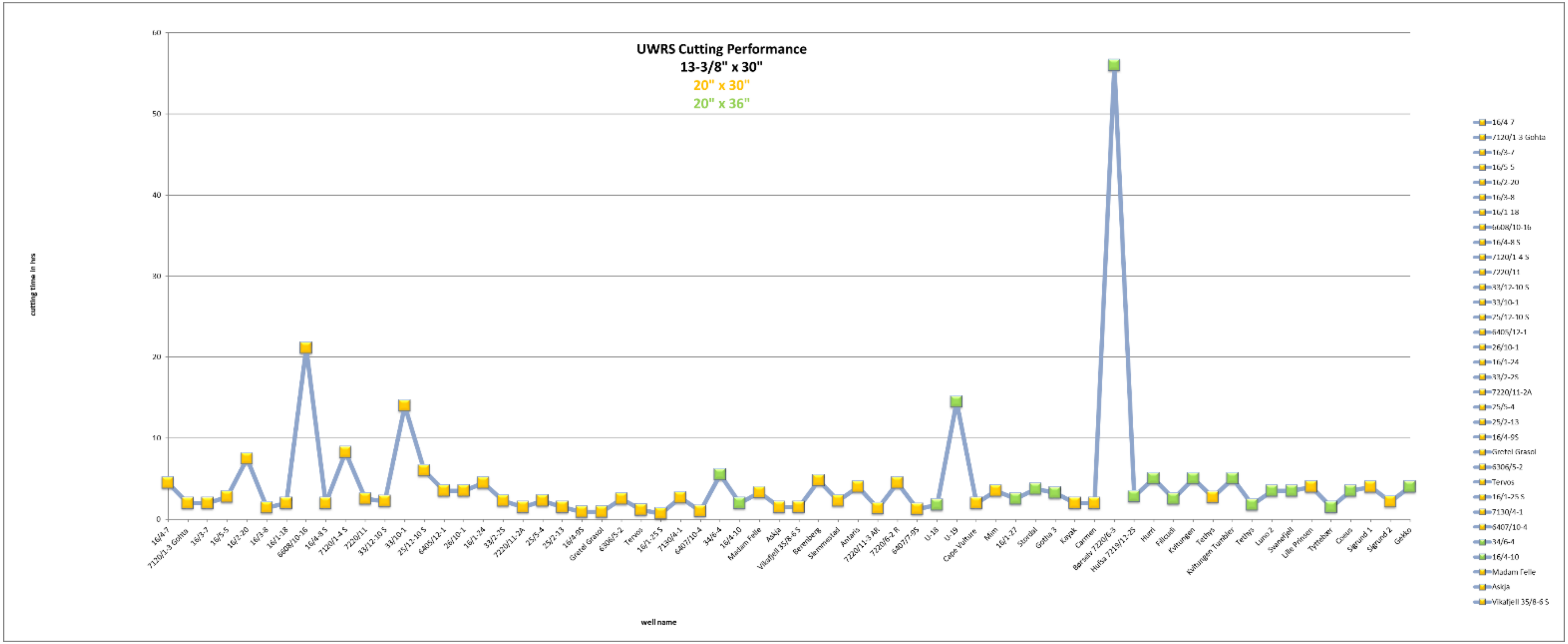

Table 5 - Cutting times BHGE mechanical cutting. Source: BHGE

For the subsea wellhead terminator to compete with Oceaneering, it must be competitive on time or cost of the total delivery. Competing on time is not absolute necessary, but in the oil industry, it is often the most time efficient solution that has the lowest cost because the daily rental rates of the drilling service accounts for 50% of the cost of the P&A operation [75].

The AWJC has an average cutting and retrieving time of 19 hours on location, while UWRS has an average cutting time of 7,5 hours.
Based on the analysis, the two charts clearly indicate that rig operations for these operations is still more time efficient. Further, if BHGE develops a subsea wellhead terminator as efficient as the current rig-based solution, the company will have a rigless solution that can compete in the current phase 3 wellhead removal market.

12.3.1 Comparing AWJC with Mechanical Cutting

To gain more information on the AWJC, an industry source with experience in both technologies was contacted. The informant highlighted that AWJC is a well-proven technology with a strong track record, and the industry relies on this technology for cost-efficient rigless well abandoning. However, AWJC has limitations when there is seawater between the casing layers, and operations is delayed since the seawater must be removed before a successful cut can be made. Furthermore, the AWJC technology takes considerable deck space on the vessels, limiting the operator in the number of operations the vessel can perform.

13 Subsea Wellhead Estimation

In this chapter the estimates of the potential market for the subsea wellhead terminator is represented. How the estimation has been carried out and how many subsea wells have been found on the different continental shelves are represented.

13.1 Subsea Wellhead Removal: a Business Opportunity for BHGE

Subsea wellhead removal may be a business opportunity for BHGE. With the increasing decommissioning activity worldwide, the numbers of wellheads that needs to be cut and pulled

will increase, in turn increasing the demand for technology and equipment to perform this service. To calculate and express the business potential for the subsea wellhead terminator, information on how many subsea wellheads are standing on the different fields around in the world is beneficial. The number of wellheads will then provide an indication of the future demand.
Since there are no international statistics on this subject, an estimation based on the data currently available from the regulating instances on the different continental shelfs was used.

In this study, we examine the current and future decommissioning activity for NCS, UKCS, Gulf of Mexico (GOM) and the rest of the world. The thesis especially focuses on NCS and UKCS because the subsea wellhead terminator will first be tested and used on the NCS. However, the UKCS was closely examined since it is more mature than NCS and has high decommissioning activity, thus more experience in decommissioning and more available information. Located in the North Sea, NCS and UKCS share the same operational conditions and challenges. The main difference is that the UKCS is older and shallow water is more common. Rules and regulations are similar, but differences exist. Therefore, focusing on the UKCS we could gain an image of how the NCS will evolve [13] [11].

13.2 Norwegian Continental Shelf

13.2.1 NCS estimation

For the NCS, the most well-known estimation on the magnitude of decommissioning is from 2014 by Martin Straume, then the leader of Plug & Abandonment Forum [76].
Straume performed the following calculation:

$$Total\ number\ of\ wells\ on\ NCS - Already\ abandoned - Exploration\ well - temporarily\ abandoned\ wells = Number\ of\ wells\ to\ be\ permanently\ plugged.$$

Although he lacked official data, using this equation, he provided a modest estimation of 3000 active wells on NCS. Exploration wells are in 80% of the cases P&A immediately, and therefore excluded from Straume's calculations .Paragraph 88 in the activity regulations set by PSA, which states that no exploration wells should be temporarily abandoned for more than two years [77].

For this thesis and the wellhead terminator Straume's number is only to some extent applicable. When estimating the number of subsea wellheads there are two main problems with Straume's calculation. His calculation includes all the wellbores and does not separate surface from subsea.

Classifying wellbores as a wells is correct from a decommissioning standpoint since each wellbore must individually undergo P&A because operations must be run in one wellbore at a time. When estimating the number of subsea wellheads, one must consider several wellbores may have the same wellhead (Figure 28 [78]).

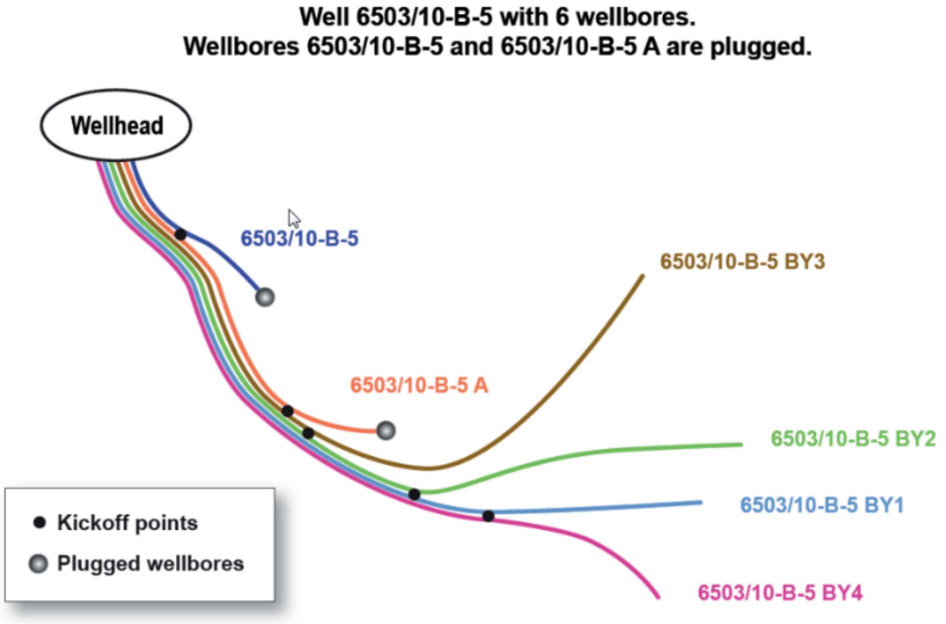

Figure 28 - Illustration of wellbores

The Oil & Gas Authority UK (OGA) insight report provides some decommissioning data on the activity in in Norway from 2017 to 2027.

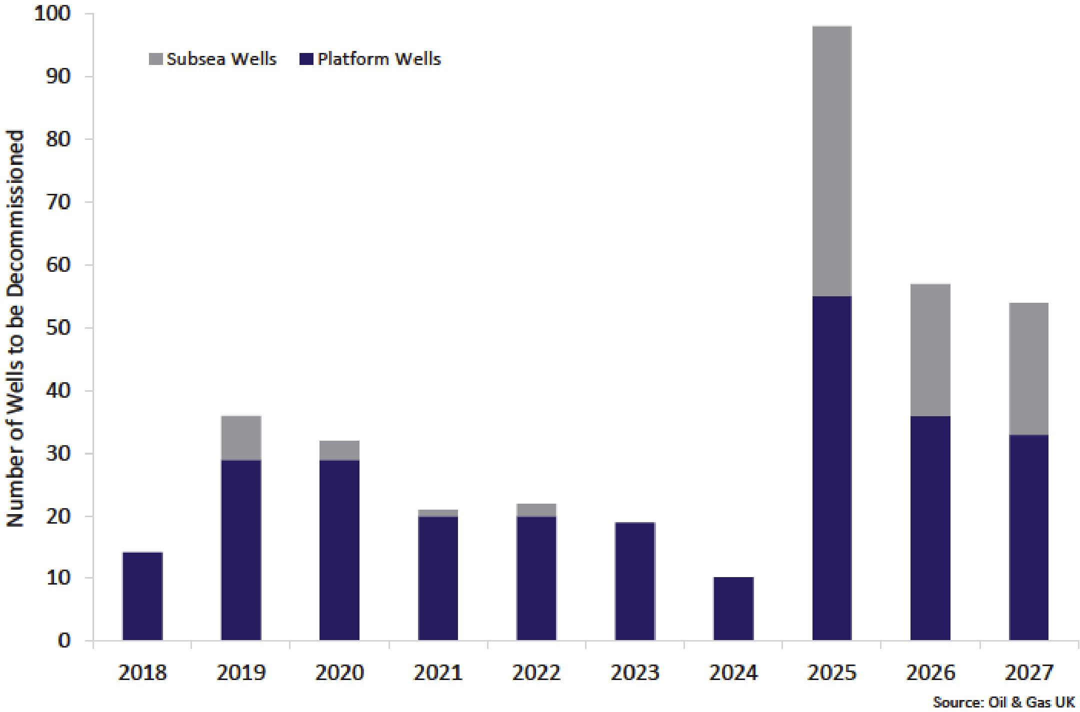

Figure 29 - Number of wells to be decommissioned on NCS the next decade

Norway expects to decommission an average of 22 wells each year through to 2024, after which there is a significant increase in the forecast. Between 2025 and 2027 some large decommissioning projects should be underway, with annual well decommissioning expected to increase to an average of 70 per year [79]. The total wells to be P&A in the next decade, according to OGA, is 363 with 98 subsea wells planned in the next 10 years on NCS.
The NPD Factpages currently do not separate on the different phases in P&A, unlike the UK version. When contacted, the NPD stated it would release a new version of the Factpages in 2019. The new version will include more detailed information on the different well status categories [80].

To estimate the number of subsea wellheads located on the NCS, data from the NPD had to be sorted and filtered. The wellbores were separated so that the data only include the main well once. This was done by using pivot table and only counting the main well ID once. The next step was to separate the surface wells from the subsea. The initial plan was to discover the distribution of surface and subsea wells on the NCS from other sources. Then, the NPD informed that it was possible to separate the wells in the excel data sheet using the column *Havbunnsinstallasjoner* which directly translates to a “Seabed installation”. This column could be separated into “Yes” or “No”.

The different well statuses are described below, including explanations of why the difference is included in the estimation [78]:

- Closed wells have been closed for a shorter or longer period and were included in the estimation since the wellhead is still on seabed.
- Drilling describes wells presently being drilled or are undergoing P&A; these wells were not included in the estimation since the final status is unknown.
- Junked describes wells are finished due to technical issues. P&A is not required on these wells according to NPD. Not included.
- Online/Operational wells are ready for production or are currently producing or injecting, so they were included.
- P&A wells are plugged and abandoned from closed fields, including P&A exploration wells; these are not included in the estimation since they are already abandoned.
- Plugged describes wells are P&A from still operating fields, including wells plugged against the reservoir but still possible to re-enter at a later stage; these wells then have undergone abandonment phase 1 or 2, but NPD does not separate these as the UK OGA does. These were included in the estimation since the wellhead is still installed.
- Predrilled describes wells that have been pre-drilled; these were included in the estimation.
- Suspended wells have been temporarily abandoned and require all three phases of P&A; thus, they were included in the estimation.

Status Subsea	#Wells
Closed	224
Drilling	3
Junked	12
Operational	562
P&A	44
Plugged	412
Predrilled	11
Suspended	12
Total	1280
Number of Subsea Wellheads On NCS	**1221**

Table 6 - Estimation of number of subsea wells on NCS

Using pivot table function in Excel and separating subsea from surface and filter to only include the main well once, it was possible to complete the calculation on the number of the subsea wellheads installed on NCS.

$$Total\ number\ of\ subsea\ wellheads\ on\ NCS = 224 + 562 + 412 + 11 + 12 = 1221$$

13.2.2 Wells Drilled on NCS

The NCS is not as mature as the UKCS or the GOM. The NCS still has new wells being drilled. From the NPD, the statistics indicates that around 200 development wells are being drilled each year. This number increased each year from 1970 to 2000, and has stabilized at around 200 wells. Thus, activity is still high, and many fields have planned production to beyond 2050. For comparison, the decommissioning cost on UKCS in 2020 will account for 10% of the total expenditure in the oil and gas industry, but NCS has a much lower total estimated expenditure at only 3% for 2020. However, both shelves' expenditures for decommissioning will rise in the next decade [81].

13.2.3 DNV GL Estimation

Another legitimate source is DNV GL. An article estimated that well decommissioning is 44% of the total cost of decommissioning on NCS. Offshore wells on the NCS represents a significant cost for operators and the government. Moreover, there should be large incentives to reduce the cost for offshore well decommission, which the subsea wellhead terminator aims to achieve.

Further, the article estimates that there are 2350 wells on the NCS that will need to be plugged and abandoned in the future, and 3000 wells are planned to be drilled in the future [33].

13.2.4 Temporary Abandoned Wells

Information on temporarily abandoned wells is not publicly available. The PSA was contacted and provided data on temporarily abandoned wells. According to the PSA, all production wells with hydrocarbon zones abandoned after 2014 shall be P&A permanently within three years if the wells are not continuously monitored. Further, all wells shall be secured before they are abandoned so that well integrity is safeguarded when they are abandoned.

Every second year, the PSA gathers information from the operators on the number of the temporary abandoned wells and their future plans. The PSA stated that the number of temporary abandoned wells have been stable for the last four years [82].

#Wells	2014	2016	2018
Surface	163	199	185
Subsea	119	51	86
Exploration	N/A	13	7
Total	**282**	**263**	**278**

Table 7 - Temporary abandoned wells on NCS. Source: Email correspondence with PSA

13.2.5 Exploration

The exploration wells have not been included so far in the thesis. All exploration wells require all phases of P&A. The exploration wells are a potential market for BHGE and the subsea wellhead terminator. All exploration wells have a subsea wellhead since these exploration wells are drilled before any surface installation is installed.
There are two reasons exploration wells are P&A immediately after they are drilled. First is rules and regulations. As paragraph 88 in activity regulations set by the PSA, no exploration wells in NCS should be temporarily abandoned for more than two years [10].

Another reason is that all the required companies to perform the P&A is already on the well location. Drilling services are on location with all the related services onboard: cementing, fishing, wellhead, casing, ROV, logging, geologist, and drilling and mud fluids. Most of these resources will also be needed for the P&A operation, and therefore, completing the P&A immediately is an efficient solution since all resources are already mobilized.

To perform this operation rigless, all required resources would have to be remobilized for the P&A. Service companies often have high mobilization costs for equipment and personnel because of the resource's mobilization demands. Mobilizing for a single operation would in most cases not be beneficial for either party. This problem could be solved by completing campaigns or batch P&A operations. This solution has been implemented for wellhead removal on exploration wells. The operators then postpone all the wellhead removals on their exploration drilling. When they have accumulated a large enough number, they initiate a vessel wellhead removal campaign [83].

Industry insiders working in exploration drilling gave an explained why this practice has not been used often and why wellheads are still being retrieved by rig: the location of the exploration wells must be close to each other. If the wells are not close, the margins will be lost in transit between the different locations. Furthermore, the operators must spend resources planning and following the operation. If the wellheads are in an area with fishing activity, a trawl structure is required. Temporarily abandoned wells will sometimes also require a tree cap and inhibitor to protect the well for marine growth and debris. These extra measures produce additional costs.

The insider meant that to P&A the exploration well after it was drilled required less work for the operator. The cost savings where not yet significant enough to have campaigns on wellhead removal for exploration wells.

Today, wellhead removal campaigns are a suitable solution for developed production and injection wells. If a field has ceased production and will be decommissioned, a high number of wells will be close together. The industry insider also mentioned that some exploration wellheads close to a shutdown field had been temporarily abandoned and included in a removal campaign.

Exploration drilling is often seen as a place where the operators test new technology, and this is where BHGE will test the subsea wellhead terminator. For the well decommissioning of exploration wells, the technology improvements have been in well design to improve the P&A operation.

13.2.6 Typical exploration well on NCS

A typical exploration well on NCS has a slimhole design, which begins with a 36-inch conductor. Then, an 18 ¾-inch high pressure wellhead housing that is welded on a 6 meter 20-inch extension joint that is slimmed down to a 13 3/8-inch casing through a welded swage. The next layer of casing is a 9 5/8-inches and is landed off with a casing hangar or downhole on a casing liner-hangar. The reservoir is then drilled with an 8 1/2-inch bit. Figure 30 illustrates a typical exploration well drilled on NCS in 2019. The image has been censored by request.

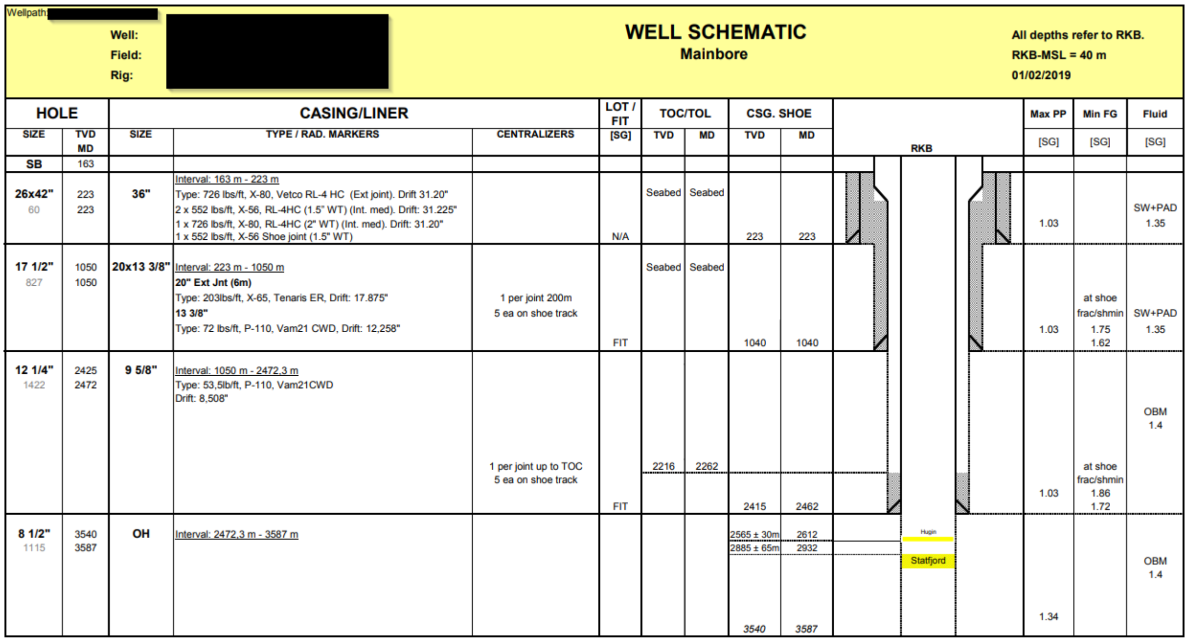

Figure 30 - Well schematic of an exploration well drilled in 2019

The schematic of the top-hole section is identical to what will be used to test the subsea wellhead terminator.

This slimhole design makes completing P&A easy since it only requires cementing, cutting and pulling of the 9 5/8-inch casing and then cementing, cutting and pulling of the 13 3/8-inch casing together with the subsea wellhead. This process results in lower costs and a shorter operation time.

Since the well decommissioning scope has been reduced because of the slim design, there is a lower benefit in delaying the well abandonment. Reducing days per well and keeping cost low on exploration drilling is important as the operator can drill more wells. However, any equipment that could speed the drilling faster will always be a beneficial. The subsea wellhead could be run while the BOP is pulled in the main derrick. This operation would save time and cost. Since the exploration wells could be a potential market for the subsea wellhead terminator, estimating how many exploration wells that are drilled on NCS would help identify the potential market.

13.2.7 Estimation of Exploration wells on NCS

The NPD Factpages historical data on the exploration wells drilled each year can be used to estimate the number of exploration wells being drilled each year. The table from NPD illustrates that in the last 10 years, an average of 40 exploration wells have been drilled per year. [78] [84].

13.3 United Kingdom Continental shelf

A great deal of information on UKCS is publicly available. Each year, the OGA's "Decommissioning Insight Report" is published. The report collects and presents data on both completed decommissioning and future work on the UKCS. Since the report makes data easily available to the public, it is beneficial to operators, service companies and the UK government.

Service companies use the report to estimate the business potential and the future need for decommissioning equipment and technology. The insight report aims to widen supply chain awareness of future demand for services and enables companies to plan and develop equipment and technology used in decommissioning.
The operators use the report as an overview of decommissioning activities on the UKCS and to locate potential collaboration partners. Operators also use the report to keep track of their own activities and progress and estimate how many assets they must put aside for future decommissioning.

To lower cost of decommissioning, the OGA has also made a public wellbore search showing the current wellbore status. The wellbore search has many similarities with the NPD Fact Pages. However, the UK version has more information related to decommissioning. [80] [49] [85].

For example, the UK version includes the current status criteria indicating how far in the P&A phases the wells are. If the status for a subsea well is set to 'Abandoned phase 3', the wellhead is removed, and the well is successfully plugged and abandoned. If the status is 'Abandoned phase 2', the wellhead is still standing on the seabed. Referring to 5.3 P&A Phase Description. The OGA has many reasons to make information about the UKCS decommissioning scope publicly available. For instance, the OGA wants to inform the industry about the magnitude of scope to improve technology development, collaboration, experience sharing, and transparency and reduce cost. Cost leadership in decommissioning is essential to extend the UKCS's productive life, encourage reinvestment in new opportunities and increase the total revenue generated, providing higher incomes through government taxation.

The United Kingdom is recognised as one of the global leaders in decommissioning. The country increased its focus on decommissioning when the oil price had a downturn. The total number of wells decommissioned in 2017 rose above the number of new wells drilled for the first time. This trend is expected to continue in the coming years unless there is a significant increase in development drilling, exploration and appraisal activity. The cumulative forecast decommissioning expenditure over the next ten years on the UKCS is £15.3 billion or about 170 billion NOK. This estimate is lower than those completed in 2016 and 2017, indicating the drive for efficiency, coupled with cost control and re-phasing of work, has led to lower estimated total expenditures on decommissioning. [79].

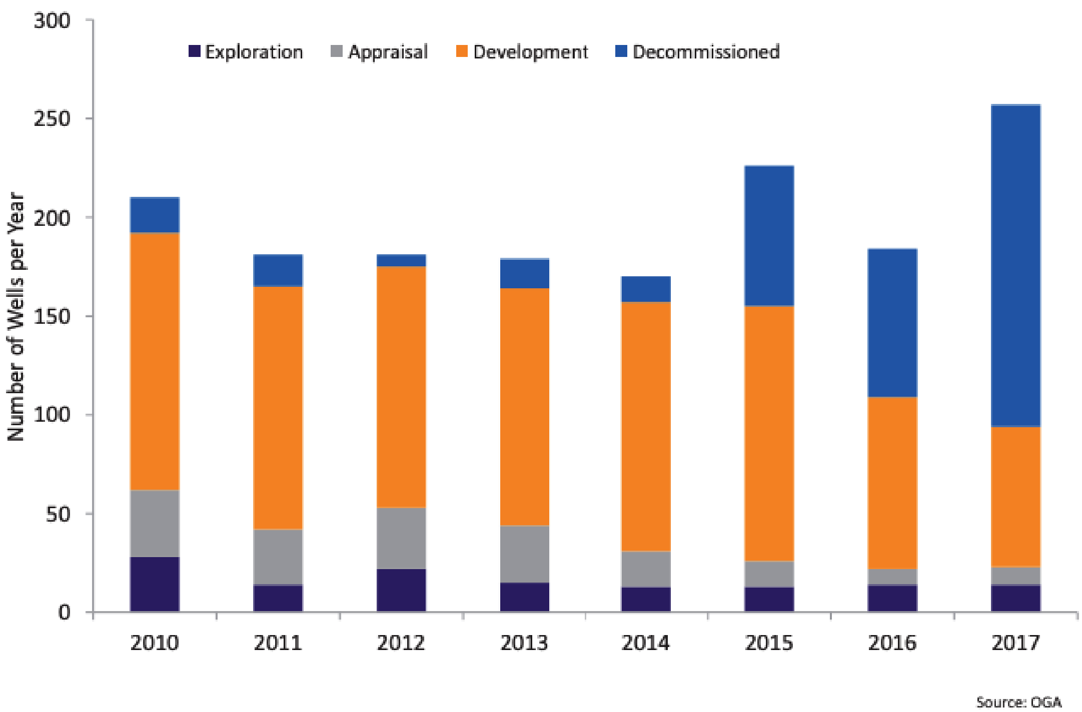

Figure 31 - Number of drilled wells vs decommissioned

Decommissioning is around 8% of the UK's total expenditure on the UKCS and will probably increase to around 10% by 2020. Thus, the cost of decommissioning is not a significant proportion of the total cost. In addition, UKCS is a mature shelf with high decommissioning activity [79] [85].

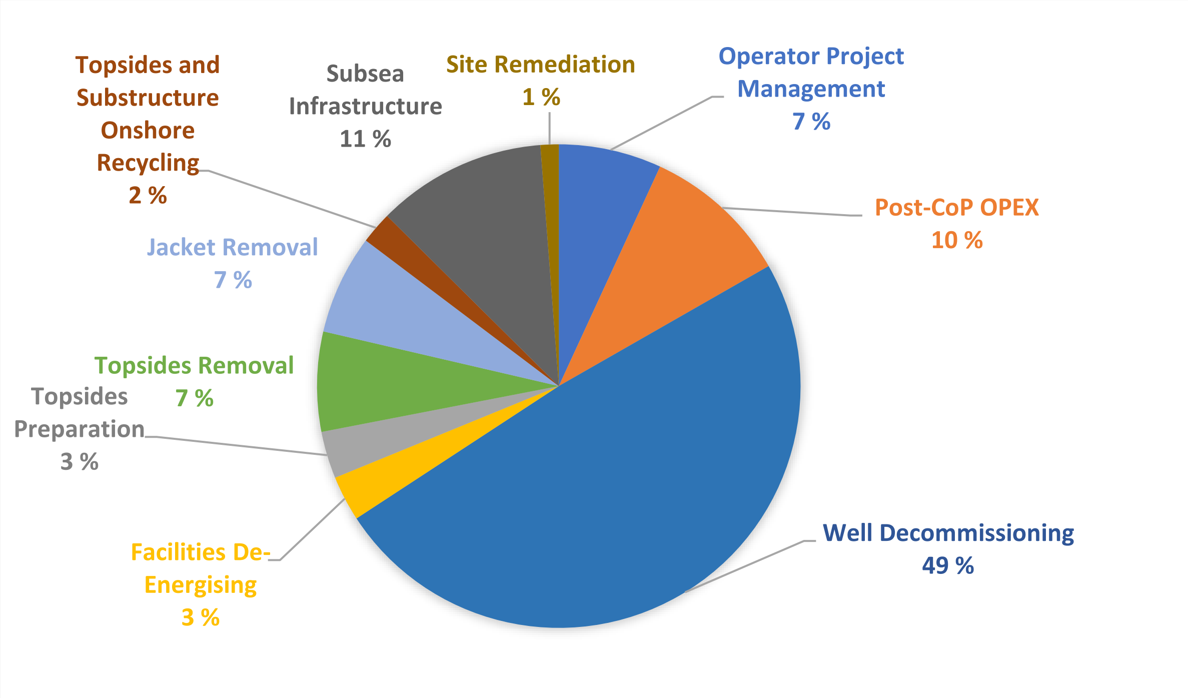

Table 8 - Overview over decommissioning costs on UKCS

The OGA cost estimation report from 2017 states well decommissioning will be the largest part of decommissioning, accounting for 49% of the total expenditure. The 2018 report verifies this estimation is still valid. Well decommissioning includes all four phases of P&A. However, cost differences exist, depending on the type of well: platform, subsea or exploration.

Table 9 provides the estimated price per well in the northern North Sea. The well decommissioning cost for subsea wells is higher than for platform wells. Subsea wells are costly to abandon due to MODU rental and vessel capacity. The results of the report indicate that there is a small reduction in cost for subsea well decommissioning. There are high incentives to reduce the cost of subsea well decommissioning, which the subsea wellhead terminator project aims to achieve.

Well Decommissioning	2016 Survey Average	2017 Survey Average	2018 Survey Average
Platform Wells	£5.38 million	£4.88 million	£4.19 million
Subsea Development Wells	£10.93 million	£10.11 million	£9.33 million
Exploration and Appraisal Wells	£6.98 million	£6.92 million	£5.02 million

Table 9 - Average well decommissioning cost

The insight report states that there are a total of 2379 wells to be decommissioned on the UKCS over the next decade. Of these, 1465 are located on the UK side, and 39% of these wells are subsea. The report states that 363 wells are planned for decommissioning in the next decade in Norway, and 27% of these are subsea. In the Netherlands and Denmark, a total of 83 subsea wells will be decommissioned; most of these have surface wellheads [86].

The total subsea wells to be decommissioned the next 10 years in the North Sea is then 752 [79].

Since all installed subsea wellheads must be removed, one could estimate the total number of subsea wellheads to be removed beyond the next decade. Here, we must consider the new wells that have been drilled, which is discussed later in the thesis.
Then, we use the UK's OGA Wells Insight report to estimate the status of all the wells on UKCS to determine how many will need decommissioning in the future.

Table 10 provides a good overview over all the wells that have been drilled on UKCS.

UKCS well stock and their status. (1964-2017)

	Well Type					
Well Status	**Exploration**	**Appraisal**	**Dev Platform**	**Dev Subsea**	**Combined Development**	**Totals**
Completed (Operating)			1506	622	2128	2128
(Completed Shut In)			386	310	696	696*
Plugged			224	43	267	267
AB1 & AB2	239				409	648
AB3 (Permanently Abandoned)	2345	1145			645	4135
Totals	2486	1373			4015	7874

Table 10 - Well stock on UKCS

The well status categories, as well as why or why not each was included in the subsea wellhead estimation is provided below:

- *Completed* (operating/shut in) indicates wells on fields in which there are still reserves and which represent the UKCS active well stock. These were included in the estimation of subsea wellheads since these are complete wells with no decommissioning.
- *Plugged* refers to wells that are not considered active, and the wellbore is plugged. These well are possible to re-enter at a later stage. Plugged wells were included in the estimation of subsea wellheads.
- *AB1 & AB2* stands for abandoned phase 1 and phase 2. These wells are possible to re-enter, but re-entry would require a significant amount of work. AB1 and AB2 were included in estimations of subsea wellheads.
- *AB3* (permanently abandoned) refers to wells considered no longer accessible. Here, the wellhead has been cut and pulled and was therefore not included.

The different well types are described as follows:

- Exploration wells are, in most cases, P&A immediately after they are drilled and are no longer accessible. The exploration and appraisal wells were included in this estimation because most subsea wellheads are immediately cut and pulled. The potential for exploration wells being a market for the subsea wellhead terminator is discussed later in the thesis.
- Dev Platform is classified as surface wells. These wells were not be included in the estimation because of a dry tree and wellhead.
- Dev Subsea indicates wells with wet trees and wellheads. There are fewer subsea wells on UKCS because UKCS is in shallow water and the technology for subsea wells was developed after the majority of UKCS fields had been developed. The developed subsea wells were included in the estimation since this type was the primary objective.

	Dev Platform	Dev Subsea	Percentage Subsea
Completed (operating)	1506	622	29 %
Completed (Shut In)	386	310	45 %
Plugged	224	43	16 %
AB1 & AB2	286	123	30 %
Total	**2402**	**1098**	**30 %**

Table 11 - Overview over well stock on UKCS and number of subsea wells

For the estimation, we needed the number of developed subsea wells in the well types AB1 and AB2. This number was found by assuming that the distribution of developed subsea wells is the same as for the other well status categories. This number was then calculated by finding the percentage of each well type and averaging these. Then, the following calculation was possible:

$Total\ number\ of\ subsea\ wellheads\ on\ UKCS = 622 + 310 + 43 + 123 = 1098$

Using the average percentage of 30% subsea wells from the other developed wells, gives 123 subsea wells in AB1 & AB2. The total estimated number of subsea wellheads on the UKCS is then 1098 [86].

13.4 North Sea

Oil&Gas UK has collected decommissioning data for all the countries operating in the North Sea. In this section, data we collected from the yearly "Decommissioning Insight Report" by OGA is presented in the table below [79].

Region	#Wells	#Subsea wells	%Subsea
UKCS	1465	571	39 %
NCS	363	98	27 %
Netherlands	419	80	19 %
Denmark	132	3	2 %
Total	**2379**	**752**	

Table 12 - Wells to be decommissioned the next decade in the North Sea

Table 12 indicates the number of wells to be decommissioned in the next decade (2018-2027) in the North Sea. The number of subsea wells is calculated from the percentage the report. From the calculation we see that the UKCS has high decommissioning activity, planning to P&A over 50% of its well stock the next decade.

13.5 Gulf of Mexico

The GOM has the highest number of wells plugged in the world, an estimated 25,000 wells, half of the number of the wells drilled [87].

There is a high percentage of platform wells in the GOM because of the shallow water. Subsea wells are not needed or desirable in shallow water because well protectors or fixed platforms can be employed for isolated small reservoirs, so there is no advantage to use subsea wells [88].

GULF OF MEXICO SUBSEA WELL INVENTORY CIRCA 2017

	< 400 ft	> 400 ft	Total
Drilled	112	1,331	1,443
Permanently abandoned	73	178	251
Remaining	39	1,153	1,192
Producing	8	375	383

Source: BOEM, March 2018

Figure 32 - GOM subsea well stock

Figure 32 indicates the number of subsea wells in the GOM. In total 1192 subsea wells will require P&A in the future [89].

Here, a subsea well occurs when both wellhead and tree are located on the seabed. The table is from the Bureau of Ocean Energy Management (BOEM), who is the US regulating instance for offshore oil and gas industry. [90].

Estimating the number of subsea wellheads to be removed is difficult since in the GOM reefing of oil and gas equipment is more common than in the rest of the world. Many decommissioning projects have been complete in GOM with reefing. Reefing occurs when an operator leaves manmade structures on the seabed to create artificial reefs. Reefing has clear economic benefits since it greatly reduces the cost of decommissioning. From an environmental standpoint, however, this subject is controversial. Some say reefing could boost marine wildlife, while other environmentalists say leaving the equipment could increase discharges and contamination of the sea from the oil and gas sector. [91].

13.6 Rest of the World

As an international service provider, BHGE has the entire world as a potential market. Therefore, an overview of all the wells in Asia, the Middle East and Russia, particularly subsea wells for the subsea well terminator, is of interest. [92].

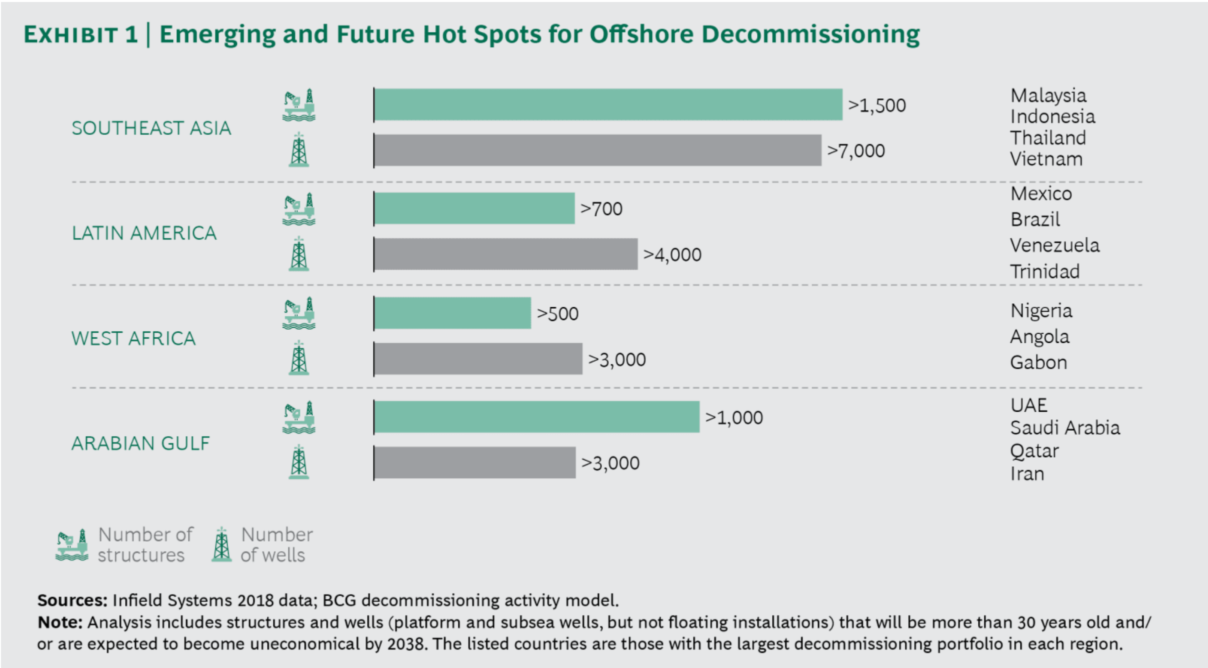

Figure 33 - Overview over well stock

Decommissioning in the Asian Pacific appears to be an enormous task for which the stakeholders are unprepared. Unclear government regulations coupled with a lack of experience in the region could mean a steep learning curve with high initial costs and potential for mistakes. These mistakes could be opportunities for large service companies as inexperience often leads to one-stop shop contracts being given to service companies. The Asian Pacific is therefore a promising market for BHGE with 35 000 wells to be decommissioned according to Wood Mackenzie [93].

According to Rystad Energy, the total number of active wells in the world is 40 000 [94].

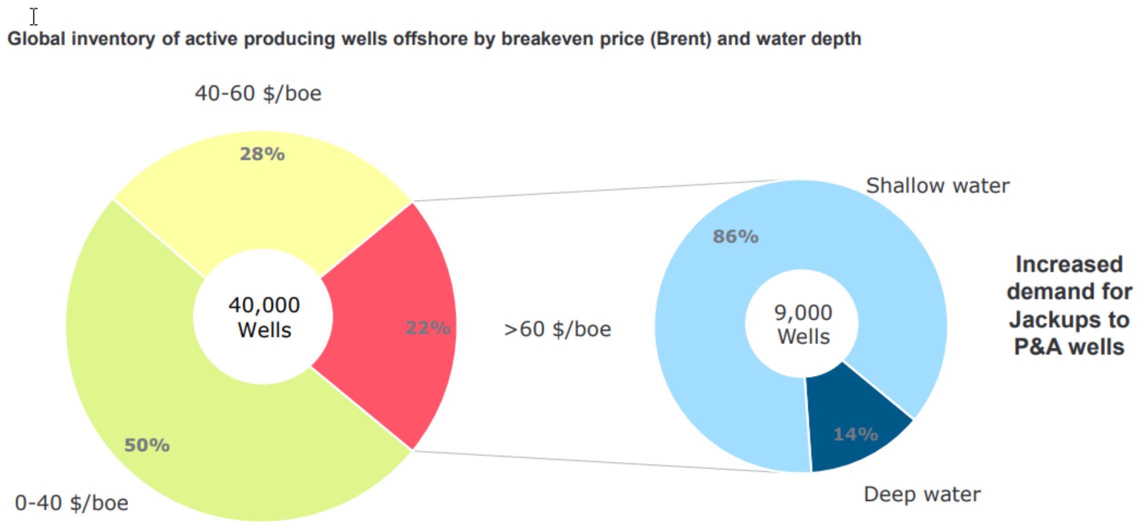

Figure 34 - Global active wells, Rystad Energy

14 Development Cost Estimation

To convince management and the local organization to support the project, the project team made a cost estimation of total cost to develop and test the prototype. Management needed to be onboard since it allocates resources to the different projects within the organization. A cost estimation is therefore included in this thesis. To estimate the development cost for the project, the cost of each component had to be estimated. Since the cost are only estimates, they may deviate from the actual costs.

14.1.1 Cost of Hydraulic Motor

In the early stages of the project, the team realized that the hydraulic motor would be the long lead item, or the piece of equipment with a delivery time that could directly affect the overall project lead time [95].

The hydraulic motor is a critical component since it replaces the mud motor normally used to rotate the HC. The hydraulic motor needs to be nearly identical to the mud motor in terms of rate per minute (RPM) and torque capacity. A sourcing process was initiated to try different suppliers to find a suitable motor for the subsea wellhead terminator project. Finding a hydraulic motor matching the requirements was more difficult than expected, but the project team eventually located a motor from a supplier outside of the oil and gas industry. This hydraulic motor was usually used in excavators and construction equipment. The price of the hydraulic motor was estimated at 200,000 NOK after correspondence with the supplier.

14.1.2 Cost of Drillpipe X-over

Machining a special drill pipe connection is a frequently occurrence at BHGE as many of its tools require special connections. After some research, the team found that the project’s drill pipe needed to be machined in two workshops to complete the connection. The estimation was set to almost double a normal connection: 125,000 NOK.

14.1.3 Hercules Cutter

The HC will not give the project any direct cost. Since this tool is in the rental fleet of Baker Hughes service tools in Norway. The project will then rent the tool when its available and not allocated to another project. This is done to keep the cost as low as possible on the project. The tool will have some internal cost for BHGE since it would have to be mobilized and require maintenance when it is returned. This internal cost is not included in the estimated cost.

Figure 35 - Hercules cutter

14.1.4 H-4 Connector

The H4 connector was not available on the rental fleet here in Norway. However, a connector located in the UK met the project requirements. After some discussion, the UK connector was sent to Norway, and it had an internal cost for the Norwegian rental fleet. However, the connector could be used for pressure testing a wellhead housing after the project is finished. No project cost was listed for the connector since it is a rental item.

14.1.5 Special flange

The cost of the flange was the hardest to estimate since it would be custom made when the connector had arrived. The flange was estimated at 200,000 NOK, including a safety factor.

Development cost

- Equipment:

Equipment	Modification	Cost – NOK
Hydraulic motor	Similar torque & RPM as mud motor.	200 000 NOK
X-over from hydraulic motor to cutter. (DP connection)	X-over	125 000 NOK
Special flange	Flange + swivel between H4 and Hydraulic pump. ROV inlet for pressure to adjust cutter knifes forces.	200 000 NOK
H-4 Connector (No modification)	No modification, Utilize existing asset	No modification, Utilize existing asset, transfer from ABZ
Hercules Cutter with stab sleeve	Solid Piston.	No modification, Utilize existing asset.
Estimated Development cost		**525 000 NOK**

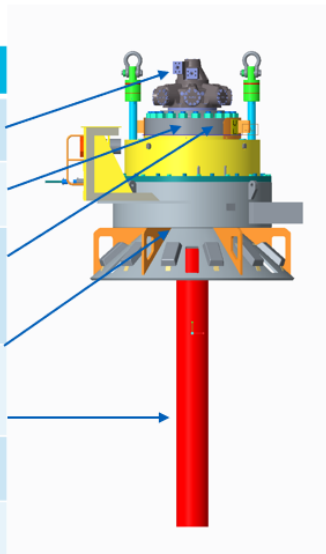

Figure 36 - Estimated development cost

14.2 Testing of prototype

This thesis estimated cost of an onshore test of the prototype. Renting space in workshop was estimated at 100,000 NOK. The engineering cost is estimated at 200,000 NOK after discussion with the engineering department. The internal cost are transport and labour cost for testing.

The prototype will be tested locally in Norway. This test will be as realistic as possible to simulate the equipment's actual operating conditions. The wellheads planned for the test are BHGE's MS-700 high fatigue wellheads, which have thick walls and are hard to cut. Performing the test on these wellheads will indicate whether the subsea wellhead terminator is able to cut wellheads of all sizes. The required wellheads had to be obtained for the test. Cut wellheads have no value, except for the shipping cost to test site.

Figure 37 - Cut wellheads that will be used for testing

Test stage	Comments	Cost NOK
Development Cost	Calculated earlier	525 000
Cut test and internal cost	Utilized old cut wellheads, Blades for HC	100 000
Workshop	Rig up in water pit. Perform different cuts.	100 000
Engineering	Engineering from concept to test prototype. Drawings.	200 000
Estimated Development Cost		**925 000**

Table 13 - Test cost estimate

The results show that the subsea wellhead terminator will cost under 1 MNOK to test and develop the prototype.

14.3 Investment Opportunity for BHGE

BHGE has now a pilot project going where they are going to test the concept of a mechanical subsea wellhead terminator. The project has an agile approach to deliver a low cost and time efficient test of the concept. The concept is to modify the mechanical HC tool to run it rigless.

To assess the projects feasibility the plan is to test the concepts operational performance. By doing so BHGE will see if the project is worth to continue develop. The focus when developing new technology is making sure its suited for the purpose it is designed for. To test the concept BHGE will create a prototype and do an onshore test. If the onshore test is successful, the next step will be to conduct a field test offshore.

The client has orally agreed to test the subsea wellhead terminator on a contract where the HC tool is planned to be used. The tool will then be run offline on wire from a drilling rig. If the subsea wellhead terminator fails, there will be a contingency in a HC tool that is ready to run on drillpipe. The offshore test will then have low risk and cost for the operator and BHGE.

If the testing of the prototype is successful, BHGE will then have to evaluate and decide if the concept should be developed to be a finalized tool in their equipment portfolio. Before deciding to go for the investment decision BHGE should conduct a comprehensive feasibility study of the new product development.

If finalizing and commercializing the prototype, BHGE must acknowledge that this process would be more extensive and resource demanding than developing and testing the prototype.

From an investment standpoint, this method of technology development has lower barriers than traditional project development in oil and gas since the initial investment to finance the equipment is lower than for traditional equipment development.

Developing new technology for oil and gas has high barriers because there are many standards and regulations in addition to high demands for equipment. One of the barriers is the industry's high start-up costs. Here BHGE has an advantage since this barrier is lower for established service companies.

Using existing technology has several advantages. First, operators are more open to try the new equipment since it has been used in operation before. Second, using existing technology reduces the development cost, and the time it takes to develop the equipment and reach the market is lower.

Disadvantages of using the existing technology is that the current use is not what the technology was initially design for. The technology's use could also prevent BHGE from developing new technology. Finally, the existing technology might become outdated sooner than a fully new developed technology. The subsea wellhead terminator is a low risk, low cost investment that may give high returns and opportunities benefiting the rise of decommissioning activity.

14.4 Wellhead Removal Campaign

To visualize the business potential of the subsea wellhead terminator, the project team decided that the thesis should include a fictive case study of a subsea wellhead removal campaign. The case study examined a campaign with BHGE as a one-stop shop supplier of a phase 3 P&A campaign. The campaign included five wells spread over seven days.

Here, BHGE will have all the aspects of the campaign, where the largest part of the scope is the rental of a vessel with ROV capacity. Finding updated daily rates on vessels was not easy. A supplier with a fleet of offshore service vessels was contacted. The company provided an estimated daily rate of 350,000 NOK including ROV capacity. The vessel service company requested to stay anonymous.

The table below provides the estimated profit with a lump-sum of 900,000 NOK per well, with the estimated costs: vessel rate, personnel, project planning, variable and costs associated with the subsea wellhead terminator. The lump-sum is based on input from the customer and competitive prices in the market.

Description	Cost NOK
Revenue (Lum sum, minimum 5 wells)	4 500 000
Vessel 7 days including ROV, fuel	-2 450 000
Subsea wellhead cutter	-250 000
BHGE Personnel (2 ea. 12 000)	-168 000
Variable Cost	-250 000
Project cost planning	-300 000
Total Project Profit	**1 082 000**

Table 14 - Potential wellhead campaign, using the subsea wellhead terminator

The subsea wellhead cutter cost is for maintenance, mobilization and demobilization, and BHGE personnel cost is to cover day and night shifts for seven days. The variable cost includes logistics, spare parts and unforeseeable events. Project planning is a large cost because it includes: planning, risk and execution of the campaign. The case study campaign has a profit of 24%.

15 Discussion

In this section the key research results will be discussed. The subsea wellhead terminator is explained with advantages and disadvantages for further developing the project. Further, the future decommissioning activity is explained and how regulations influence decommissioning cost. Finally, the challenges associated with well decommissioning, and competitor analysis is discussed.

15.1 Subsea Wellhead terminator

This thesis identifies the subsea wellhead terminator as a possible low hanging fruit for BHGE since it requires fewer resources to test and develop than innovating an entirely new technology. The company's UWCS is already field proven and transforming this technology from rig-based to rigless would be a business opportunity for BHGE.

The pros and cons for the subsea wellhead terminator project are included below to structurally visualize the benefits and negatives of the project.

The project's positives are the following:

- Requires fewer resources to test and develop than to innovating new technology.
- Transfers technology and internal collaboration and based in field proven technology.
- Fills the gap in BHGE's portfolio and increases profit in one-stop shop contracts, instead of hiring ae third-party supplier to perform the cut.
- Requires less deck space on vessel/rig than AWJC.
- Could be run offline from a rig.
- Smaller environmental footprint than AWJC.
- The subsea wellhead terminator can cut with seawater between casing layers, unlike AWJC.

The project's drawbacks are as follows:

- Competing against AWJC in a conservative industry is difficult because AWJC is a field proven technology many years' experience in rigless P&A and has a strong track record.

- HC is limited to 20-inch and 30/36-inch, while AWJC can cut through multi-casing string 7-inches to 36-inches with cement in between casings
- Cutting time is, estimated to be longer than the rig-based HC.
- The technology is not patent protected, and competitors have similar mechanical cutting technology.
- The method could risk stalling the cutter inside the wellhead, resulting in NPT and difficulties to retrieving the wellhead and the tool.

Based on this research in this thesis and on the calculations of how few assets BHGE needs to allocate to transfer an already field proven technology to a well decommissioning market with a steady demand, BHGE should continue the project and conduct the onshore field test to determine how it performs in simulated conditions.

A lot of the further research depends on how it performs on the onshore test in terms of cutting capacity and duration. After the test BHGE should do a thorough feasibility study or evaluate to shut down the project, depending on the test results. With a successful test our opinion is that BHGE should go ahead and commercialize the project.

Our estimated cost to test and develop the project is less than 1 MNOK, this is considerably lower than other developing projects in the oil and gas industry.

15.2 Estimation of Decommissioning Activity

At BHGE's requested, this thesis studied future well decommissioning activity. Extensive research indicated reports, articles and sources vary as to how much decommissioning activity that is planned the next years. However, they all state well decommissioning activity will steadily increase in the future.

Many reports, like this thesis, focus on the number of wells since this is an industry method of mapping demand. However, the number of wells may not be important from an investing standpoint. For BHGE, the most important factor is that its project has a business market.

1 The results in this thesis estimates that there are 1221 active subsea wells on the NCS, and 98 is planned to be decommissioned in the next decade. On UKCS the number of active subsea wells is 1098, and 571 will be decommissioned in the next decade. For GOM, there are 1192 active subsea wells to decommissioned in the future.

15.3 Rules and Regulations

The laws, legislations, guidelines, regulations and recommendations that govern well decommissioning must be strict enough to ensure that P&A operation is safely executed, but these rules should not be too strict. The cost escalates when new, strict regulations are implemented, and it is important to avoid overregulation in this area to reduce the cost of well decommissioning. Rules and regulations must be adjusted to be ready for rigless P&A operations, making sure technology development is not stopped by regulations. Achieving an adequate level of regulation is a collective industry responsibility, involving all regulators.

15.4 Well Decommissioning Challenges

In this subsection, the current P&A challenges and how these can be met with reducing measures is discussed.

15.4.1 Economical and Technology Challenges

Operators wants to postpone P&A operations to take advantages of future technology development and the fact that future cost is lower than present due to NPV. However, by delaying their P&A operations, would eventually increase the pressure on resources needed to perform those operations.

The increased pressure will lead to higher rig and vessel rates, low availability and an unbalanced demand curve for the service companies. These factors make the technology in P&A, as well as other segments of oil and gas operations, slower developing than could be achieved. If the entire operation is done rigless, the potential savings are 70% compare to rig-based [96].

For rigless technology to improve, it must be used to be developed. Thus, P&A operations must be spread over a longer time period, so the service companies have time to develop technology and have a balanced demand.

15.4.2 Planning and collaboration challenges

Many operators are experiencing challenges in planning P&A, because data is not collected or centralized and sharing knowledge and experience between parties are limited. These limitations are especially apparent for wells in which the ownership has been transferred from one operator company to another.

Detailed pre-planning of a well decommissioning is crucial since cost escalation due to unforeseen events can prevent cost-effective solutions. There are several reasons why the data is not centralized in one source: the data collected differs in quality, amount and format. For old wells, the data is often lacking and of poor quality. Due to earlier operators and industry not understanding the potential future value of data.

There are large economic advantages for operators to collaborate regarding P&A. According to Marathon Oil, operators could reduce P&A cost 30% to 40% if they were willing to take a collaborative approach with rival producers. Some advantages are economics of scale, knowledge sharing and increased learning curves and experience. With programs such as Rushmore, abandonment performance review operators would gain competitor intelligence and data from previously abandon wells and see current best practices. Sharing data between competitor's allows for a significant cost reduction on well decommissioning.

15.4.3 Well design challenges

When the operators plan their new fields and wells, they devote little to no attention to the P&A aspect. Choosing technology and equipment designed to be decommissioning in the future, would reduce costs and make the operations safer with regards to well integrity, especially for subsea installations.

15.5 Competitors analysis

The main competitors have been evaluated through a competitor analysis. The results indicate that competitors have similar strategies and focus areas, such as one-stop shop contracts for well decommissioning. A couple of the competitors have rigless technology for well decommissioning, which subsea wellhead terminator needs to compete against. Companies such as Schlumberger, TechnipFMC and Oceaneering have already acquired small fleets of vessels to perform rigless well decommissioning. The evaluation on whether BHGE should acquire a vessel fleet is not covered in this thesis.

The results indicate that Schlumberger and Oceaneering have established in the market for rigless subsea wellhead removal. However, the competition on the subsea wellhead removal are less than BHGE encounter on other technologies. Whether the project can compete on cutting capacity and duration is too early to conclude before the onshore test is conducted. However, if the subsea wellhead terminator performs as the rig-based HC, it will be competitive on the current market.

16 Conclusion

Since the world's portfolio of oil and gas wells are ageing, there will be a steadily increase in well decommissioning activity. This study has found that developing technology for rigless well decommissioning is a key factor for reducing cost. Since BHGE, aims to be a one-stop shop service supplier in well decommissioning, we conclude that BHGE should increase research and development on rigless well decommissioning.

Wide variation exists in the number of wells estimated by scientific reports, despite large variations, all reports concludes decommissioning will increase in the future.
We estimate that there are 1221 subsea well on the NCS, and 98 wells will be decommissioned in the next decade. For the UKCS, there are 1098 subsea wells, and 571 wells will be decommissioned in the next decade. For the GOM, there are 1192 active subsea wells to be decommission in the future. The industry uses the number of wells to calculate demand, we therefore conclude there will be a potential demand for the subsea wellhead terminator.

In this thesis we calculated the cost for developing and testing the subsea wellhead terminator to less than 1 MNOK, considering how few assets BHGE needs to allocate, we recommend continuing the project and conduct onshore and offshore tests to see how the subsea wellhead terminator performs.
The conducted competitor analysis indicates that competitors have similar strategies as BHGE, such as one-stop shop contracts and rigless wellhead removal. Whether the subsea wellhead terminator can compete on cutting efficiency is too early to conclude before further testing is completed. However, we can conclude that if the subsea wellhead terminator performs near the rig-based HC, it will be competitive.

17 Future Research

Recommendations for future research:

- Conduct the onshore and offshore test to find out how the subsea wellhead terminator works in simulated and real conditions.
- A more extensive analysis of the competitors should be conducted. The analysis in this thesis is completed on limited resources, BHGE will have the capacity to do a more detailed analysis.
- Investigate if competitors are developing similar technology.
- If a more accurate number of subsea wells worldwide is required, BHGE should purchase this from a consultant company. The authors contacted different consultant companies, but they requested substantial payments.
- Wait for the new version of NORSOK-D010, that comes out in 2019, to see how it affects P&A regulations.
- Evaluate whether BHGE should acquire a vessel fleet for well decommissioning or continue to hire from a third-party.
- A feasibility study of the commercialization of the project should be carried out.

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