



ABANDONMENT OF OBSOLETE WELLS AND INSTALLATIONS ON THE NORWEGIAN CONTINENTAL SHELF

A study into the magnitude of the technical and economic challenges.



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i Stavanger

Preface

I am a fifth year student of Industrial Economics and Petroleum Technology as part of a MSc. program at the University of Stavanger (Norway). This document is my final thesis.

For the last two years I have been working at Archer (the Well Company) next to my studies, which has given me a great opportunity to see close-up the challenges related to well activities. Also, both my parents work for an operating company, which for several years already have been abandoning and decommissioning obsolete wells and installations. So when I decided to write my thesis on the challenges associated with the final phases of wells and installations that are no longer economical sustainable, I knew I would have access to a lot of valuable information.

The aim of my thesis is to show the magnitude of the challenges related to abandoning wells and installations in a safe and cost effective manner. The scope of this work on the Norwegian continental shelf (NCS) is enormous, and will involve huge expenses using the current methods and technologies. It is therefore fundamental to develop new techniques and address these challenges in a new and innovative way.

The focus group of this study is not necessarily technical experts, but individuals involved in planning and making decisions related to future cessation projects on the NCS. I have deliberately kept the technical aspects of this study at a fairly low level, however, some basic understanding of offshore activities and operations is expected.

I would like to thank Archer, who has given me the opportunity to work on my thesis at their office alongside my regular work. Also I want to thank my counselor at UiS, Jonas Odland, for his support and assistance. And finally I express my appreciation to individuals at BP, ConocoPhillips and Statoil, who have provided me with valuable information, their expertise and insight, and not least their time.

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Abstract

An increasing number of offshore installations on the Norwegian continental shelf (NCS) are passed their peak production, they require more and more maintenance and/or investments, and are rapidly approaching their end of economic life. The final stage in an installations life is Cessation. This is a time-consuming, complicated and costly activity, but it is necessary in order to protect the environment and fulfill mandatory national regulatory requirements as well as international regulation.

This paper addresses the technical and economic challenges related to Cessation activities on the NCS.

Regulatory requirements both related plugging and abandoning wells and decommissioning installations, are covered.

Plugging and abandonment of wells is described in detail, existing techniques and technologies as well as unconventional methods. This part of the paper also discusses the magnitude of P&A on the NCS, i.e. the number wells already drilled and expected in the future and the amount of work required to plug them in a safe and prudent manner.

Decommissioning of offshore installations, including disposal, is covered in a separate chapter, describing methods, their challenges and shortfalls, as well as the anticipated amount of work needed to be done in the future.

The economics of Cessation is covered in detail, together with some deliberations around the net present value (NPV) and cost-benefit of the substantial expected costs.

In addition to the outlooks for the future, a specific example of a concrete case regarding Cessation of an installation in the southern part of the North Sea is covered.

The last part of the paper is a discussion around the changes that are required in order to approach the many challenges associated with Cessation in a cost effective manner, benefiting both the industry and the Norwegian society.

Abbreviations and Definitions

BOE	-	Barrels of oil equivalents
DNV	-	Det Norske Veritas
DSV	-	Drilling support vessel
ECD	-	Equivalent circulation density
EE	-	Electric and electronic waste
IOR	-	Improved oil recovery
MDR	-	Modular drilling rig
MODU	-	Modular drilling unit
NCS	-	Norwegian Continental Shelf
NOK	-	Norwegian Kroner
NORSOK	-	Norsk sokkels konkurranseposisjon
NPV	-	Net present value
OED	-	Olje og energi departementet
OSPAR	-	Oslo Paris convention
P&A	-	Plug and abandonment
PWC	-	Perforate, Wash, Cement
R&D	-	Research and development
ROV	-	Remotely operated vehicle
SSCV	-	Semisubmersible crane vessel
WBM	-	Well Barrier Material

Cessation:

Cessation means ending or stopping an activity. Cessation in this thesis is defined as the combined activities from planning to shut down activities on an offshore installation, including any production and/or injection wells, until the installation is removed and disposed of and the wells abandoned in a safe manner.

Decommissioning:

Decommissioning is a general term to remove something from an active status. In this paper, the term is used to describe the removal of physical installations (above the seafloor), from planning until the installation is disposed of according to regulatory requirements.

Plug and Abandon:

Plug and abandon, or plugging and abandonment, are defined as the activities involved in securing a well (production, injection or exploration) that will no longer be used, to ensure containment and no hazards to the environment.

The Norwegian petroleum act:

The full name is "Act 29 November 1996 No. 72 relating to petroleum activities", also known as "Petroleumsloven"

1. Introduction

The Norwegian oil and gas production has passed its peak, and we will most likely never see production above 3 million barrels per day (as we did in 2002).

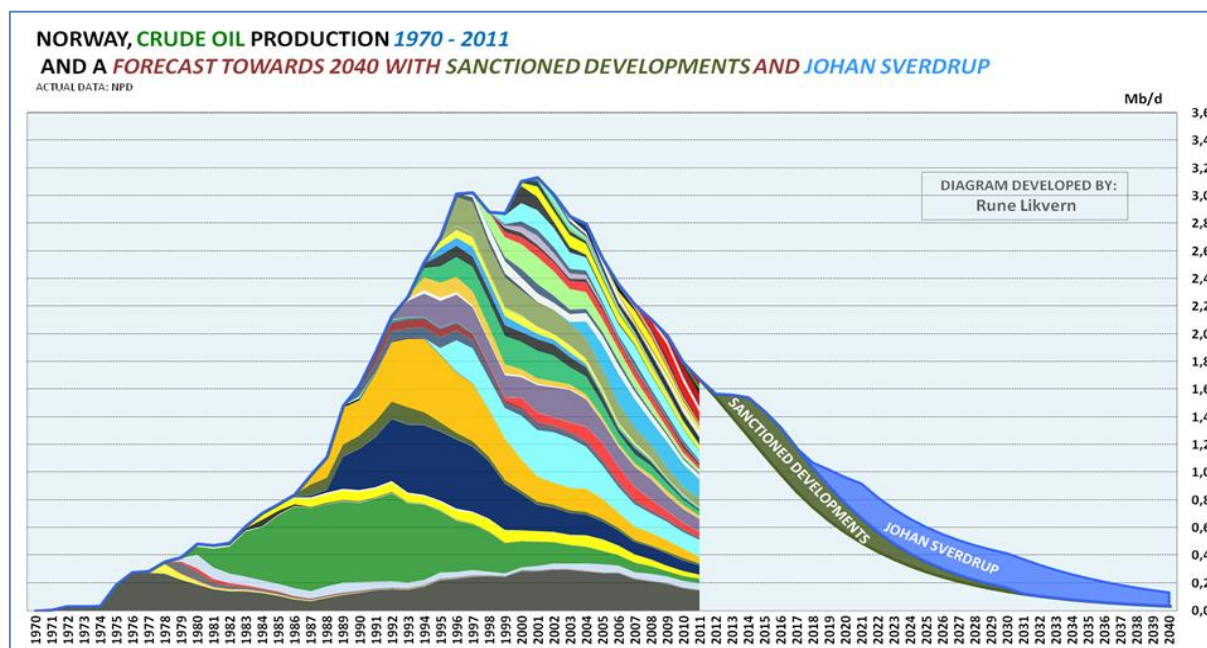


Figure 1.1 – Historical oil production on the NCS. [6]

The positive aspect in the industry is the relatively high price on crude oil.

New technologies for improved oil recovery (IOR) are being explored and implemented where they are economically attractive, in order to slow down the inevitable decline in production. Maintaining production at a level that can support continued operation, i.e. making the “tail” of the production life-cycle as long as possible, is a main focus for most mature fields.

The other side of the economics equation that determines when a field has reached the end of its life, is cost. All operating companies are focusing on reducing the normal, daily operating expenses, as well as the investments required to maintain the production. However, as fields and the accompanying wells and installations are getting older, it usually requires correspondingly increasing investments to keep them in a safe and good condition.

Eventually the income from a well, or facility, is not sufficient to pay for the expenses. Then comes the cost of abandoning the well(s) and/or facility in a safe and prudent manner, also referred to as Cessation.

The oil and gas industry, mainly the operating companies, are facing a huge task with the rising number of obsolete wells and depleted fields. Every well is required to be plugged before it can be abandoned.

And every installation above the seafloor is required to be decommissioned, removed and disposed of. Concrete sub-structures, like e.g. Troll, Statfjord and Draugen, are for the time being allowed to remain at their current location until economical viable technology for removal becomes available.

This plugging of wells and removing of facilities is an enormous task, both technically and economically. Due to the Norwegian tax regime, the operating companies can deduct all relevant expenses from their income, before paying taxes. Since the marginal tax for operating companies is 78%, this means that in effect 78% of the Cessation cost is paid by the Norwegian state (in the form of reduced income tax). It is therefore in the interest of both operating companies and the Norwegian authorities to keep these costs as low as possible, while satisfying health, safety and environment measures.

In addition to the cost, there are technical, logistical and other challenges. Several key individuals throughout the industry have expressed concern about the number of wells that need to be plugged in the near future and the cost of this overwhelming task. The substantial increasing demand for plugging and abandonment (P&A) is not easily dealt with. Without innovative ideas and new technology, keeping up with P&A activities while at the same time drilling new wells in order to maintain production, will require both equipment and manpower that is currently not available. Plugging a well with present technology takes 45 days to complete (planned), although some wells have been reported to take up to 125 wells to plug and the "best" ones are reported to take 21 days. The time needed to plug a well is heavily affected by the condition of the well. Also, on installations where a derrick is no longer available, a jack-up rig or similar is needed with a full contracted crew. This is very costly as rigs are in constant demand, and they often need to be booked years in advance. Suppliers are already having problems delivering enough rigs with today's demand while complying with the strict regulatory requirements for safety and rig specifications.

Further, plugging does not create any additional value or revenue for the operating companies, and plugging jobs are therefore often postponed as long as possible to offset the negative net present value (NPV). P&A is often seen as a necessary evil from the operator's point of view. Plugging takes time and resources away from production improving/maintaining operations, such as well-interventions and drilling of new wells.

Plugging of wells and decommissioning of installations are areas where significant improvements can be made to reduce cost, because technology and methods are old fashioned or have not yet received the proper attention.

This document aims to highlight the current available technologies, their shortfalls and where the industry is moving. It will also describe some of the challenges related to plug & abandonment of wells and decommissioning of installations, as well as discussing some of the areas where more focus is required.

2. Cessation

Cessation is ending an activity, such as production on an offshore installation. This typically follows 10 steps, depending on the type of installation in question, as described below.

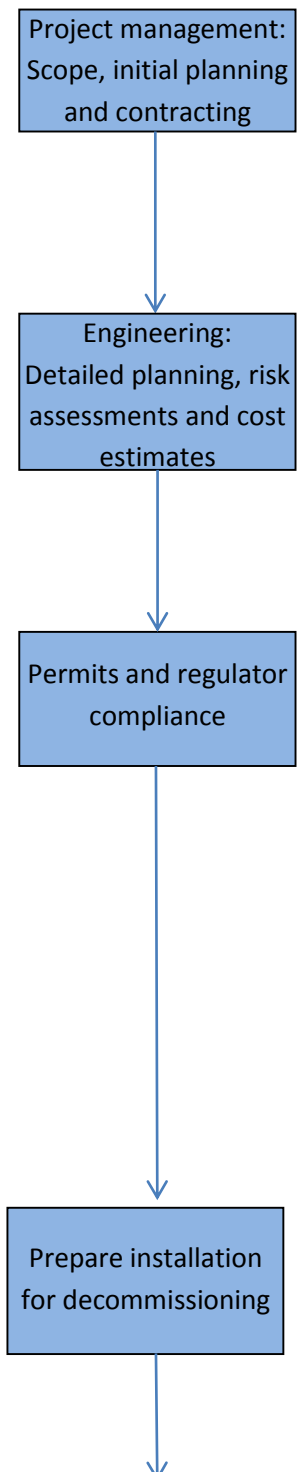
The first step in this process is project management. This starts years before the last well runs dry and is actually addressed already while the field development is in an early planning stage. The operator reviews any regulatory requirements and an overall scope of the work is presented to partners, the government and other stakeholders.

The second step is an engineering analysis. A detailed, technical plan is made, often with several options and “what if” alternatives. This part is often outsourced to several external companies. Risk assessments are conducted for approval by management. Financial analysis and costs estimates are also performed in this step.

The third step is obtaining permits and regulatory compliance. These permits need to be applied for years in advance and consultants are often hired to assure that regulations are followed. The Norwegian petroleum Act, 29 November 1996 No. 72 relating to petroleum activities chapter 5 Cessation of petroleum activities, explains the regulatory requirements by the Norwegian government. The Norwegian Petroleum Directorate can also decline the operators’ request, which is noted in section 5-3:

“If the decision is to the effect that the facility shall continue to be used in the petroleum activities or for other purposes, the licensee, owner and user are jointly obliged to make sure that future decisions on disposal are carried out, unless otherwise decided by the Ministry.” [1]

Step 4 is preparing the installation for decommissioning. After all permits are secured, the preparatory work can be started. This involves cleaning and flushing of tanks, pipes and process equipment to make them hydrocarbon-free. This cleans out any residual hydrocarbons, contaminations, deposits, etc. in the system, which need to be disposed of. The different modules on the platform are



separated by cutting interconnecting pipes and cables. The steel-jacket is prepared for removal. Pad-eyes, if not pre-installed or in acceptable condition, are also fitted to enable lifting the individual modules.

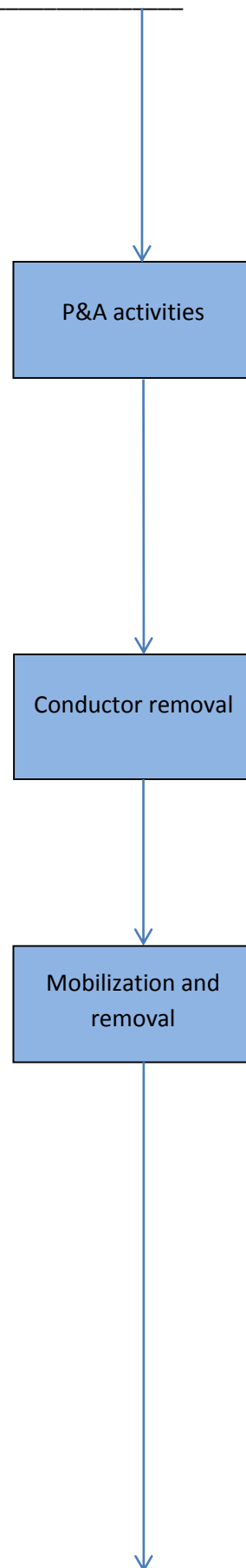
Step five involves plugging and abandonment of wells. This step is usually divided into a planning phase and an execution phase. In the planning phase, data is collected and preliminary inspections are performed. Decisions are made regarding what method(s) to use for P&A and the plan is submitted to regulatory authorities for approval. The abandonment phase involves equipment preparation, downhole equipment removal, wellbore cleaning, plugging (plugging at the bottom of the well, plugging above perforated interval(s), plugging casing stubs, annular space plugging, placing a surface plug) and pressure testing all plugs in order to verify their integrity.

The sixth step is to remove the conductors. Operators are required to remove all well components down to 5 m below the seabed. On fixed installations this means removing the conductors which is the outer piping connecting the well to the topside wellhead. There are different methods to do this. The conductors can be severed using explosives or mechanical cutting. The disconnected conductors can then be hoisted with lifting equipment and cut into manageable segments.

Step seven, mobilization and removal of installations, is started after P&A and when the conductors have been successfully removed (applicable for fixed installations). There are different ways to disassemble e.g. a platform depending on size, platform design and lifting-barge capacity.

Topside can in some cases be removed in one operation, but this requires a heavy lift-barge with sufficient lifting capacity. Other installations are too heavy, not designed for or have been modified during its life, making single-lift removal impossible. The onshore disposal facility or receiving site also needs to have sufficient capacity to receive such a huge structure.

A well-established approach is to perform a so-called reversed installation. This involves dismantling and removing modules in the opposite order they were assembled. Also, some modules can be combined and removed together, resulting in fewer lifts and smaller vessels needed for the job, although this approach is more time-consuming than the single-lift method.



Another method is to cut the modules and support structures into smaller, more manageable pieces and remove them with deck mounted cranes. This can be continuously lifted onto supply vessels returning to shore after having delivered shipping tools, equipment, materials and food to the facilities. Then only a smaller lifting barge is required to remove the remaining steel jacket. (Concrete support structures can be left in place, as described in chapter 3.2.2.)

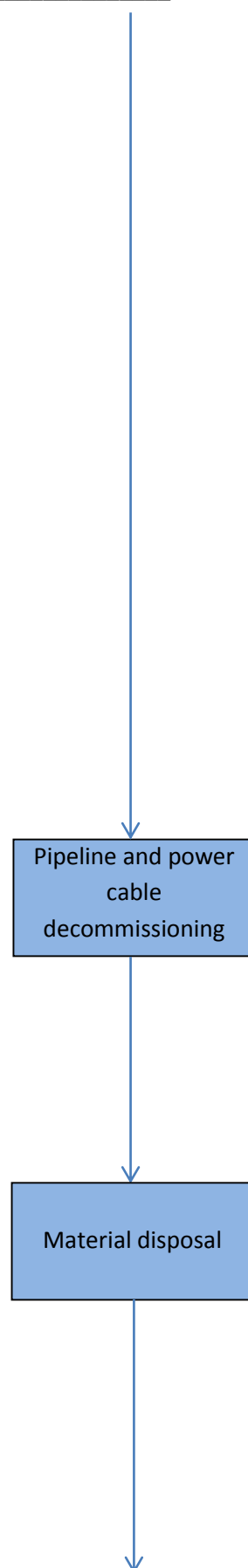
Several types of machinery are used to complete the offshore demolition work in a safe and efficient manner, for this small-piece removal method, and excavators are very well suited. They are flexible, strong and can easily adapt to different work tasks. Excavators can be used for cutting and handling of scrap, reducing the need for hazardous labor-intensive operations.

The steel jacket is lastly removed with explosives, torches or mechanical cutting methods. The legs are cut 5 m below the seabed and the jacket removed with a lifting barge. In some cases the jacket needs to be cut into smaller pieces before removal. This approach is a lot more time-consuming, but also eliminates the need for a costly lifting vessel.

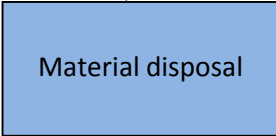
In some cases, the small-piece method of decommissioning can be run simultaneously with P&A operations.

Removal of pipelines and power cables is the eight step. Pipelines and power cables are in some cases allowed to be left on the seabed where they were installed, if they do not interfere with commercial fishing operations or constitute any environmental hazards. Pipelines are required to be left in a safe condition and needs to be flushed and purged for any hazardous or polluting material. After flushing and water filling, the open ends of the pipelines are buried below the seafloor and covered with concrete.

The ninth step is the disposal of materials. Jacket, support structure, modules, topside equipment and other debris needs to be sorted and classified. The materials are cleaned, repaired and reused if applicable, scrapped and recycled, or disposed of as hazardous waste. Large onshore facilities are needed for these operations and at present few locations are qualified or suitable.



The final tenth step is site clearance. The area where the installation was located is checked by remotely operated vehicles (ROV) and divers, for any debris left behind. Any environmental impact is noted and the area is verified as clear of any obstructions for marine traffic and fishing operations.



Material disposal

The main focus of this document will be steps 5, 6, 7 and 9 which is covered in the following chapters.

3. Regulatory Requirements

As with all other aspects of the oil and gas industry, rules and regulations established by the national government and additional international agreements, decide the framework within which the operating companies are required to address Cessation activities.

On the NCS, P&A and decommissioning is regulated mainly by the Norwegian petroleum act, OSPAR (The Convention for the Protection of the marine Environment of the North-East Atlantic) and NORSOK (Norsk sokkels konkurranseposisjon).

3.1. P&A

Permanent abandonment is defined as a well status, where the well is abandoned and will not be used or re-entered again, contrary to temporary abandonment where it is planned or expected that the well be restored to production, reused as injection, initial wellbore used for sidetrack, or similar at a later date.

Before abandoning a well, it is compulsory for the operator to leave the well in a condition that protects the subsurface and the surface environment for the foreseeable future. The operator is required to remove the wellhead, conductor and any surface casings. The conductor and surface casings shall be removed down to 5 m below the seabed, removing any risk of accidents with fishing trawlers and other marine activities. The operator is responsible for the abandoned well even after it is plugged and wellhead removed, and liable for any future problems related to the well. This could be caused by seal failure, cross flow or well fluids leaking to the surface.

According to NORSOK standard D-010, which relates to well integrity during drilling and well interventions, a permanent well barrier is required to have several qualities [7]:

- Provide well integrity for the foreseeable future
- Be impermeable
- Materials used shall not have shrinking properties.
- Able to withstand mechanical impact and loads
- Materials used must be resistant to chemicals such as H₂S, CO₂ and hydrocarbons.
- Materials used must have wetting properties for bonding with the steel casings.

Further, there are four criteria for an approved permanent well barrier stated in NORSOK D-010.

- Length
- Position
- Cross section
- Verification

3.1.1. Length

The well barrier is required to be of a certain length to ensure impermeability. Increasing length of the well barrier also increases the strength and ensures it can withstand any pressure forces from the reservoir or other inflow sources.

In general, NORSOK D-010 requires the well barrier to be at least 100 m (328 ft) long. However, a well barrier inside a casing with a mechanical plug as foundation is only required to be 50 m (164 ft) long.

3.1.2. Position

Positioning is important for the well barrier integrity. NORSOK D-010 requires well barriers to be placed as close to the source of inflow as possible. This increases the efficiency of the barrier and eliminates migration paths in the formation close to the inflow source. The formation below the barrier must be able to withstand a potential pressure buildup without fracturing. The primary well barriers (see chapter 4.2) are in addition required to extend 50 m (164 ft.) above any inflow source. Further, a well barrier in the transition zone from a casing to an open hole, is required to extend 50 m (164 ft) above the casing shoe.

3.1.3. Cross section

The well barriers are required to extend to the full cross section of the well. This includes the area inside the inner most casing, all annuli between casings, and from the formation to the outer casing, both horizontally and vertically, as illustrated in fig. 3.1.3.1.

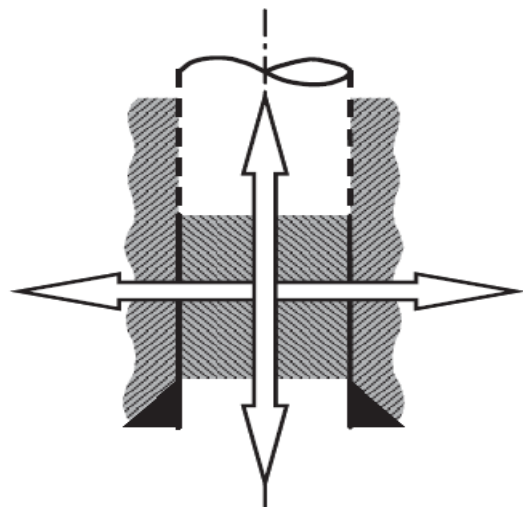


Figure 3.1.3.1 Cross section of a well barrier.
[8]

Any downhole equipment such as cables and control lines, must be removed to eliminate any voids in the barrier.

3.1.4. Verification

Verification is done by conducting a series of tests. These tests include logging, inflow testing, load testing and pressure testing. Different barriers and well conditions require different kind of tests. It is important to verify the position, length and strength of the well barriers to confirm the integrity of the well.

3.2. Decommissioning

There has been and still is, a lot of discussion related to cost-benefit value of physically removing obsolete offshore installations. In many countries it is well proven practice to convert installations to artificial reefs. Studies have concluded that oil platforms on the NCS attract fish, and that such reefs could benefit fishermen. However, the occupation of the Brent Spar North Sea oil platform by Greenpeace in 1995 has influenced Norwegian authorities. As a consequence, despite the scientific findings of the potential value, the OSPAR Commission, which has jurisdiction over decommissioning in the North Sea, has blocked this “rigs-to-reefs” approach.

3.2.1 The Norwegian petroleum act

Act 29 November 1996 No. 72 relating to petroleum activities (“Petroleumsloven”) covers the rules and regulations regarding petroleum activities on the NCS. Chapter 5 covers cessation of petroleum activities, focusing on the planning and permits for the decommissioning elements. There are very few concise requirements related to decommissioning, compared to P&A of wells. The Ministry’s main focus is to ensure that a prudent plan has been prepared.

§5-1 states the requirement for a decommissioning plan that must be submitted to the Ministry of oil and energy (OED) by the operator, at least two years before the applicable production licence expires but no more than five years before.

§5-2 states that the operator shall notify the Ministry if the facility is expected to be shut down before the current production licence expires.

3.2.2. OSPAR Convention.

The OSPAR Convention was signed in Paris on 22nd of September 1992 and entered into force on 25th of March 1998. This convention was signed by all the nations with borders to the North Sea and the North-East Atlantic Ocean. The European Union, Spain, Portugal, Luxemburg, Switzerland, France, Norway and the United Kingdom are among the signers of the OSPAR convention. The OSPAR convention prohibits any installations to be left or disposed of in the North-East Atlantic Ocean.

It is stated in article 5 annex 3:

“No disused offshore installation or disused offshore pipeline shall be dumped and no disused offshore installation shall be left wholly or partly in place in the maritime area without a permit issued by the competent authority of the relevant Contracting Party on a case-by-case basis. The Contracting Parties shall ensure that their authorities, when granting such permits, shall implement the relevant applicable decisions, recommendations and all other agreements adopted under the Convention.” KILDE

An exception from this requires individual applications for each case. No concrete installations have yet been removed from the NCS due to cost-prohibitive solutions and unsuitable technology.

Concrete platforms installed before 1978 were not designed to be removed, and some operators have received permits to leave the concrete support structure of such installations in place, e.g. the concrete tank on the Ekofisk Complex (illustrated in figure 3.2.2.1.).

Other concrete installations, such as Troll and Statfjord, are also candidates where the operators may be allowed to leave most of the concrete structure in place. Engineers are continuously looking for viable methods to remove these structures but, current options are not cost effective and/or too risky.



Figure 3.2.2.1 Ekofisk 2/4 Tank June 2013.

4. P&A - Plugging and abandonment of wells

New innovative ideas and technology to drill longer and cheaper wells and increase production, are researched and implemented continuously.

But when it comes to plugging and abandonment of wells, most operators are still using the same technologies and methods as they did 40 years ago.

The main goal of P&A on the NCS is to [8]:

- Avoid contamination of the environment
- Prevent cross-contamination of inflow sources in the well
- Prevent leaks from or into the well
- Remove well related equipment and casings down to the mandatory level below the seabed

New technologies related to P&A have not been prioritized by either operating, engineering, or supplier companies. Most of the research and development (R&D) has been focused towards maximizing production and reducing cost associated with exploration i.e. finding more oil and gas. The results of this are:

- Time and cost extensive methods for P&A
- Low supply in the market for P&A solutions
- No large niche suppliers
- Poorly plugged wells causing environmental hazards and cross-contamination from other zones in a production field.

4.1. Basic well terms

The **casing** is a pipe, and often a series of decreasing diameter pipe, which is inserted into the wellbore after a planned section of the well has been drilled. The casing serves several purposes in the well. It acts as a barrier from the formation (which might fracture and leave debris in the wellbore) to the wellbore, as well as a barrier from the wellbore to water zones or production zones (which can be contaminated with drilling fluids). Each casing also serves as a strong foundation for the consecutive drilling sections, which enables the use of high-density drilling fluid for deep wells, as well as sealing off high-pressure zones that might cause a blowout to the surface. The casing also makes wireline and coiled tubing operations easier because it provides a smooth wellbore to lower this equipment into the well.

Tubing

The tubing (production tubing) is a pipe used inside a wellbore to transport gas and liquids from the reservoir to the wellhead. This protects the surrounding casing from damages due to corrosion and erosion, and reduces any depositions of sand, scale, wax, asphaltenes, etc. The tubing is usually one of the last things to be installed in the well before production starts and one of the first things to be removed before P&A commences.

Annulus

The annulus is the void area between the tubing and a casing, between casings, and between the casing and the surrounding formation. The annulus allows circulation of fluid in the well and is essential during drilling to transport drill cuttings to the surface. A developed well usually has several annuli where the "A" annulus is between the tubing and the inner casing string, the "B" and "C" annuli are between the outer casing strings. The integrity of these annuli is monitored at the surface by gauges on the wellhead.

Wellhead

The wellhead is used to contain the pressure in the well during production, and as a part of P&A it is removed after the position of the well barriers has been verified and their integrity tested with acceptable results.

Plugs

Plugs, also known as barriers, are set at specific intervals as to prevent gas and fluid flow to the surface, crossflow between different sections of the reservoir and other inflow sources. For P&A, at least three separate barriers are required between a reservoir and the seafloor. In situations where multiple reservoirs are producing from the same well, additional barriers between the reservoirs are required.

Barriers

Four types of barriers are used in P&A activities. A **primary well barrier** is used to isolate the source of inflow (a formation with normal pressure or over-pressured formation) from the surface/seabed. The **secondary well barrier** is located above the primary one as a back-up against the same inflow source. A **crossflow well barrier** is placed between two inflow sources where crossflow is not acceptable. This barrier may also function as a primary well barrier for an underlying inflow source. These three barriers

must be placed such that the base of each barrier is at a depth where the formation fracture pressure is higher than the potential pressure below. An **open hole to surface barrier** is the final barrier to be placed in the well. This is installed to isolate any flow from exposed formations in the well after the casing(s) are cut and removed. Fluids may also be trapped between the casings. They are harmful to the environment and must be contained.

Materials

The most commonly used barrier material is Portland cement. This is also used in most concrete, mortar and stucco. The limestone and shale for producing Portland cement can be found in all corners of the world. The high availability lowers the cost of this material. Portland cement needs to be handled with care since it is a caustic material. The high energy requirements during mining and dust particles that are created during production are the main environmental concerns with this material.

4.2. Conventional methods for establishing barriers

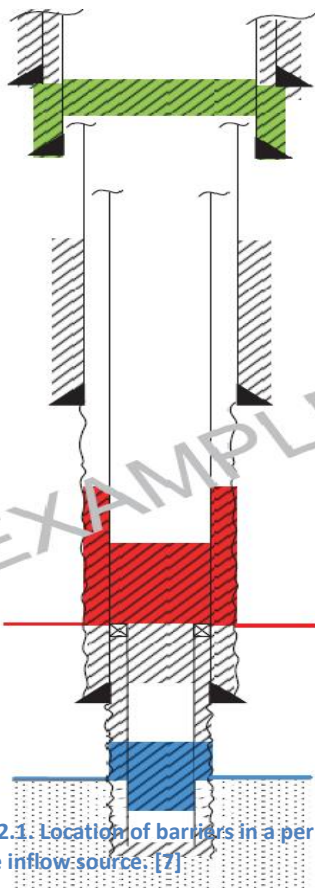


Figure 4.2.1. Location of barriers in a permanently abandoned well, one inflow source. [7]

Regulations in NORSOK D-010, Rev. 4 states that two cross sectional barriers are required above any inflow source as well as a surface well barrier. This results in a minimum of three well barriers in each well. [7]

Figure 4.2.1. on the left shows an example of the required barriers for permanent plugging of a perforated well with a single source of potential inflow.

Three barriers are displayed, in blue, red and green. The blue barrier is the **primary** well barrier. The red barrier is the **secondary** well barrier, acting as back-up to secure the well should the primary barrier fail. The red well barrier requires cement both inside and outside the 9 5/8" casing. In some places the cement used when originally setting the 9 5/8" casing, is still good and only cement inside the casing is required as a barrier.

A final **surface** barrier is also required in case of formation fracture causes the hydrocarbons to migrate from the reservoir and into the well above the second barrier.

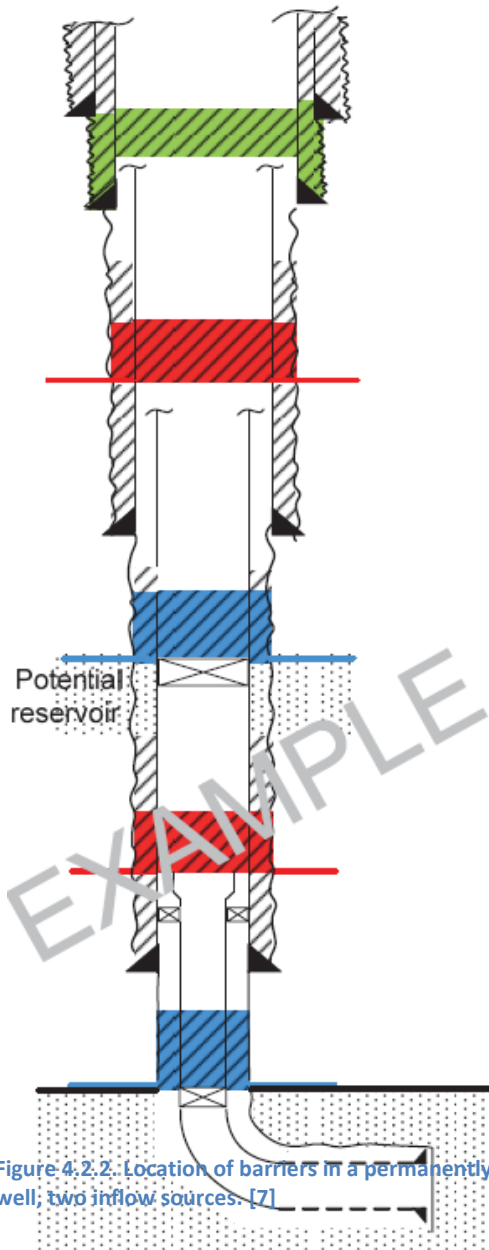


Figure 4.2.2. Location of barriers in a permanently abandoned well, two inflow sources. [7]

For a well with a secondary potential inflow source located some distance away from the producing zone, NORSOK D-010 states that two additional cross sectional barriers are required above this inflow source. This results in a minimum of five plugs in this type of wells. [7]

Figure 4.2.2 on the left shows an example of the requirements for permanent plugging of a perforated well with the possibility of inflow from a potential second reservoir.

One **primary** well barrier and one **secondary** well barrier is required above both the main and potential reservoir, as well as a **surface** well barrier.

In wells that have produced from two separate reservoir zones, NORSOK D-010 states that a barrier to limit crossflow between the reservoir zones is also required. This results in a total of four barriers. [7]

Figure 4.2.3 on the left shows an example of the requirements for permanent plugging of a perforated well with the possibility of crossflow between two separate reservoirs/zones.

In this case, the same barrier acts as a primary barrier for one zone and as the secondary barrier for another. The **yellow** barrier acts as a crossflow well barrier between zone A and zone B, as well as a primary well barrier for zone B. The **blue** barrier acts as a primary barrier for zone A, as well as a secondary barrier for zone B.

This method can only be used if the **blue** well barrier is designed to handle the differential pressures for both zone A and zone B.

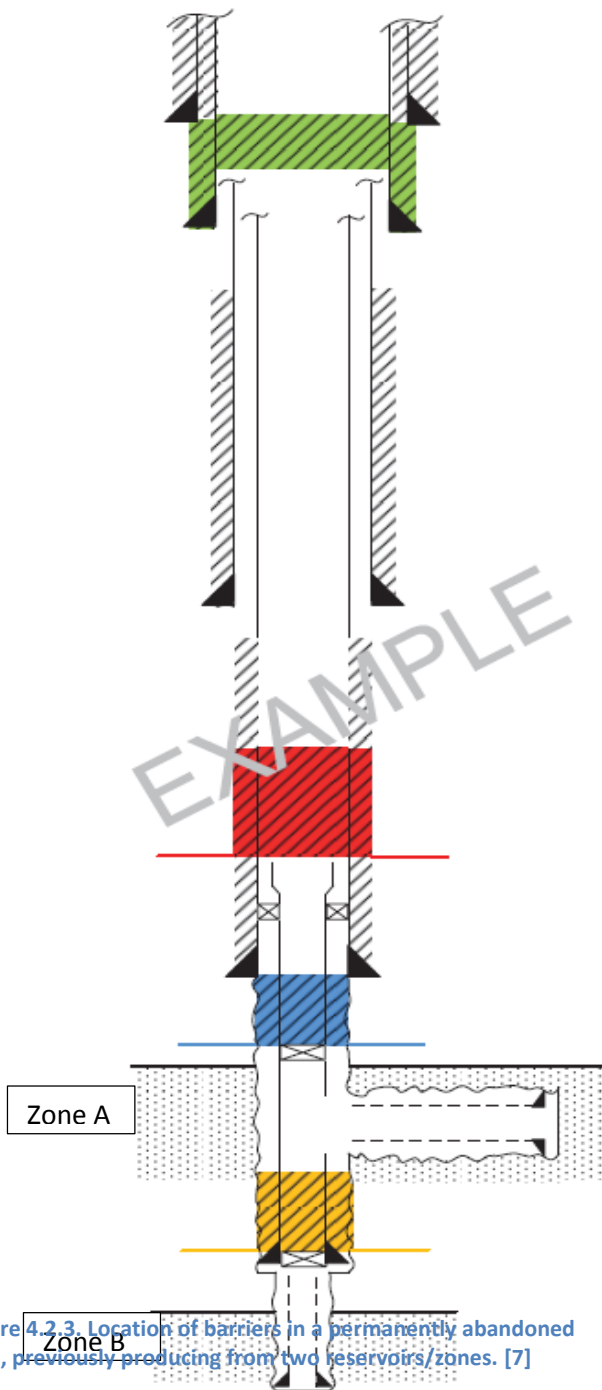


Figure 4.2.3. Location of barriers in a permanently abandoned well, previously producing from two reservoirs/zones. [7]

Another special case of plugging is when the formation consists of two or more reservoir zones that are within the same pressure regime. In this case, two or more reservoirs can be regarded as a single reservoir, requiring only two well barriers (in addition to the surface barrier). Figure 4.2.4. below shows a case with two reservoirs within the same pressure regime as shown on the left graph.

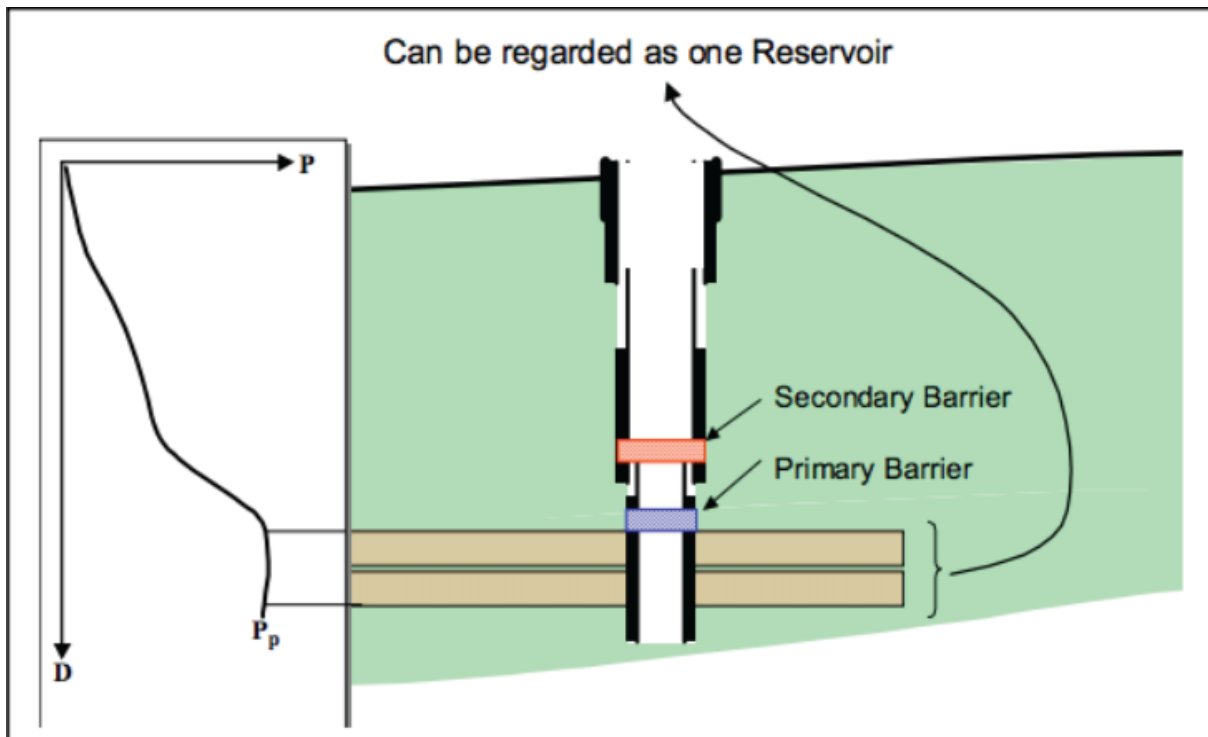
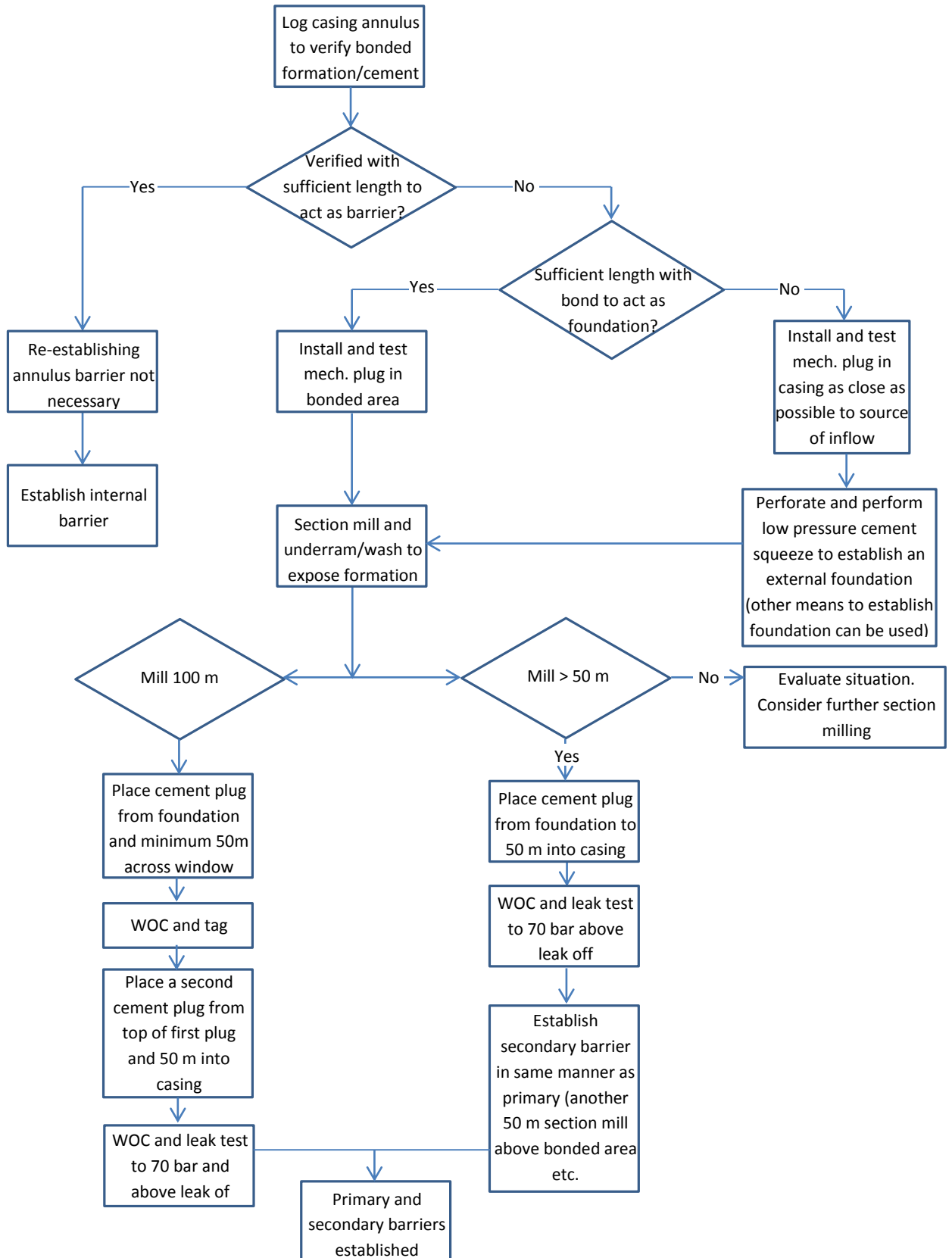


Figure 4.2.4 Two reservoirs with the same pressure regime, isolated by one set of well barriers. [7]

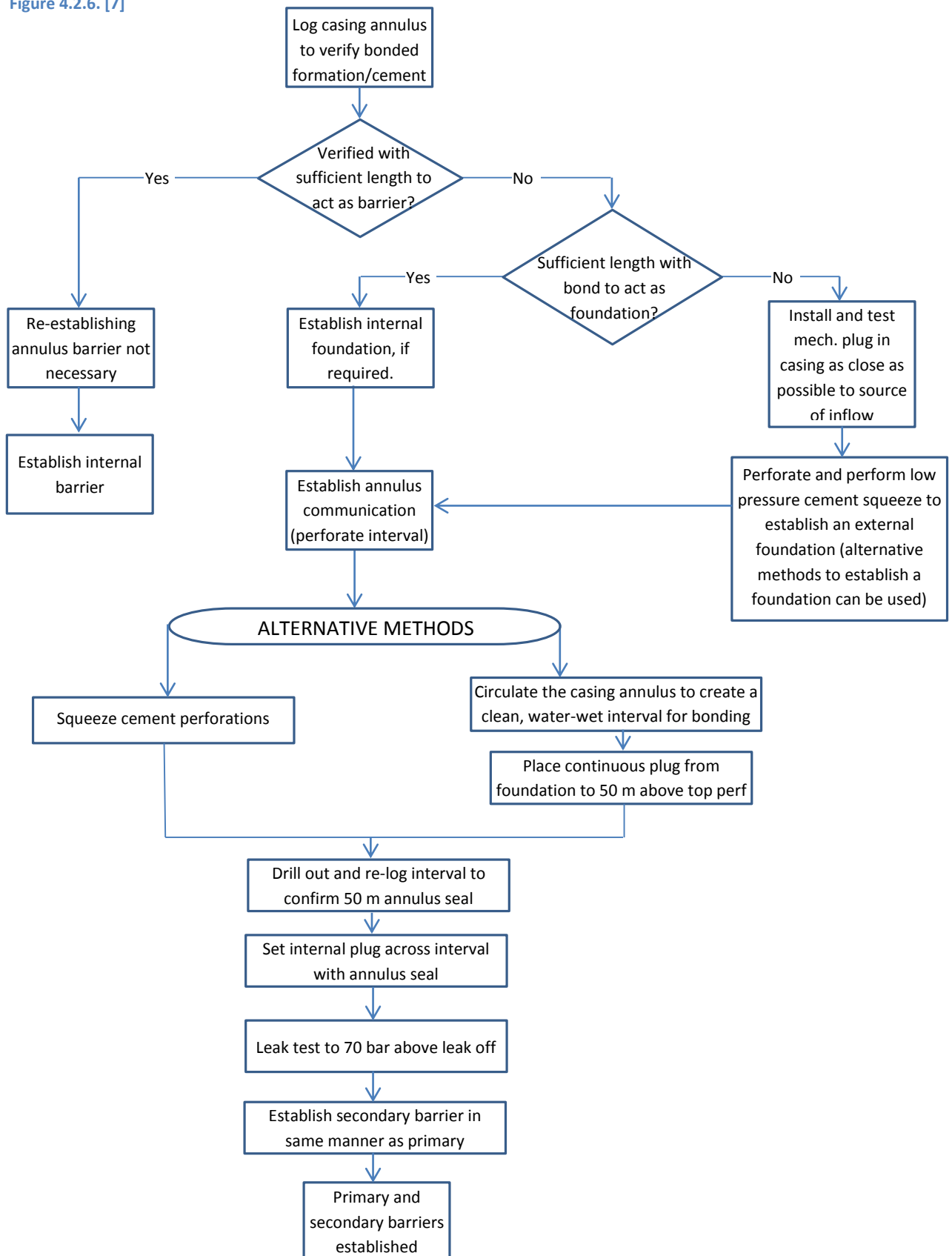
Steps during conventional P&A operations, using casing milling

Figure 4.2.5. [7]



Steps during alternative P&A method, without casing milling

Figure 4.2.6. [7]



4.3. Casing removal

Cutting the casing and pulling it upwards is required to open up a section in the casing to enable the setting of a cement plug. This requires many time-consuming “runs”. Also, this method is not always possible, for example where the casing string may be stuck from swelled shale zones, settled formation debris in the annulus or old cement. Multiple



Figure 4.3.1 Casing retrieved to surface after milling operation, containing a swarf “birdsnest”

cuts might be required, involving switching between cutting and pulling for each section. Where cutting is not possible, the conventional method is to section mill the casing.

4.4. Other applications for P&A

P&A is done for different reasons. Oil and gas wells that are no longer producing enough hydrocarbons to make them economically viable, injection wells that are no longer needed due to end of production, or wells with wellbore issues that requires them to be closed and work-over is not an alternative option.

Slot recovery is another situation where P&A is required. This operation involves establishing a new bottom hole location while using the existing top part of the well. The bottom part of the well is plugged and a so called kickoff plug is set to offset the drill bit to the desired direction.

While a well is waiting for slot recovery, well interventions, a long shutdown or further development, the well may be temporary abandoned. Temporary abandonment (TA) requires the possibility to re-enter the well quickly and safely in case of complications. Mechanical plugs are more common in these situations than cement plugs. NORSOK D-010 states that the integrity of the well barrier in a temporary abandoned well only has to last twice as long as the planned abandonment period.

4.5. Estimated magnitude of P&A on the NCS.

By the end of 2013, a total of 5306 wells had been drilled on the NCS. 1469 of these were exploration and appraisal wells and were plugged relatively soon after. The remaining 3837 are production, injection and monitoring wells that have to be plugged eventually. Approximately 800 of these are already plugged and abandoned, leaving roughly 3000 wells for future P&A. Many of these wells are several decades old and their condition is poor, limiting the use of coiled tubing or wireline for efficient plugging methods.

By using extrapolation, one can presume that by the year 2050, a total of 7000 wells need to be plugged or are candidates for P&A. This estimate is based on trends developed over several years of operation on the NCS. With the Barents Sea still in the early stages of exploration and new wells are constantly being drilled at existing fields for increased oil recovery (IOR) such as water injection, this number seems very probable and could even be argued to be too low. As reservoirs are being depleted, new zones are relatively more profitable than the already producing ones, resulting in even more wells that need to be drilled.

The estimated 7 000 wells will take 210.000 rig-days to plug and abandon, assuming each well takes 30 days on average with today's technology (which is very optimistic). Using 10 rigs, with zero downtime will require more than 57 years to perform P&A on all these wells. It is obvious that new technology is desperately needed to achieve this huge task, especially in a cost efficient manner.

4.6. Technical challenges related to P&A

P&A is not as simple as just pouring cement down a wellbore and wait for it to settle. The entire process related to P&A is challenging, very time consuming and costly for the operator. With the strict regulations for P&A, operators are striving for new cost effective solutions without compromising the quality required. New technology and methods to reduce the time and resources needed, will save the operators and the tax-payers substantial amounts of money.

4.6.1. Barrier quality

The quality of the barriers placed in the well is essential. The operator who performed the P&A responsible for the well for all foreseeable future, even if the production license has expired or there is a new operator. Leaking barriers might take years to discover and fix and can in the meantime cause massive environmental damages. Re-entering a leaking and plugged well is something the operator

wants to avoid. Setting a high quality barrier the first time is a lot better than the costly re-enter alternative.

4.6.2. Swarf handling

Milling a casing generates steel swarf that needs to be transported to the surface and separated from the well fluids. Swarf is some of the worst material for a drilling rig to handle. It is cuttings in metal form and highly erosive to any equipment it comes in contact with, downhole and on the surface. So called “swarf units” and “shakers” are used to separate it from the well fluid. Smaller cuttings can easily follow the well flow past this equipment. Magnets are therefore installed in the flow lines to try to remove some of these smaller cuttings, but need constant cleaning to stay effective. Some fine swarf is always passed through the system, causing damage on downstream equipment like pumps and valves.

Lifting the swarf to the surface requires a high density and high viscosity drilling fluid, which causes high equivalent circulating density (ECD). High ECD can cause fracturing of the formation and loss of well fluid.

The separated swarf is stored on deck in containers and shipped onshore using a supply vessel. Personnel handling swarf are at risk of receiving cuts and stings from this material. Swarf starts to oxidize when it gets in contact with oxygen. This oxidation generates heat and there have been reported fires in containers containing swarf. Consequently, deciding to mill a casing raises many health, safety and environmental (HSE) concerns and must therefore be addressed thoroughly.

4.6.3. Lack of rigs

Today’s techniques and methods for P&A require jack-up rigs, semi-submersible rigs, fixed installation drilling rigs or drill ships to perform the required work. Pulling the tubing and casing requires heavy lifting capacity, while casing milling requires powerful pumps to bring swarf to the surface and a rotating well string for milling. With drilling of new wells, maintenance of existing ones and plugging of old and damaged ones, all competing for the same rigs, plugging often receives the lowest priority since it does not provide any additional revenue. The high demand on drilling rigs maintains a high rig-rate which makes all drilling activities expensive and thereby promotes postponing of P&A activities.

Jack-up rigs are currently the main vessel used for plugging of wells where there is no derrick available at the set location. These rigs are also used for drilling production wells, injection wells and performing well-interventions. Jack-ups are an excellent choice because they can connect to existing installations such as old drilling platforms where the derrick has been removed. Jack-up rigs are also used on unmanned wellhead-installations such as the Northern and Southern flanks the Valhall field.



Figure 4.6.3.1. Jack-up rig Maersk Reacher on the Northern Valhall wellhead platform. [10] on

4.6.4. Old Technology

There has been no significant change in the technology used in P&A since the start of the Norwegian oil & gas industry. Most of the technological advancements have been done in areas related to improved recovery and reducing cost of exploration. The plugs used for barriers have become more reliable with more advanced cementing materials, but the methods used for the operation remain basically the same. This is mainly because research to improve cements has focused on achieving better completions. The end result for the limited research is low cost- and time-efficiency when performing P&A.

4.6.5. Increasing time consumption for P&A operations

The time required to perform P&A operations has increased significantly from 2003 to 2010. An increase from an average of 16 days per well to 35 days per well is a 120% escalation. During this period, the NORSOK D-010, rev. 3 was introduced and may have contributed to some of this time increase. Operators today are planning on using 40-70 days for a typical well and up to 120 days in special cases. With the huge amount of P&A work ahead, a rising average of days per well is a step in the wrong direction.

Figure 4.6.5.1. to the right shows the average plugging time for development wells on the NCS from 2000 to 2010, numbers were provided by Statoil ASA.

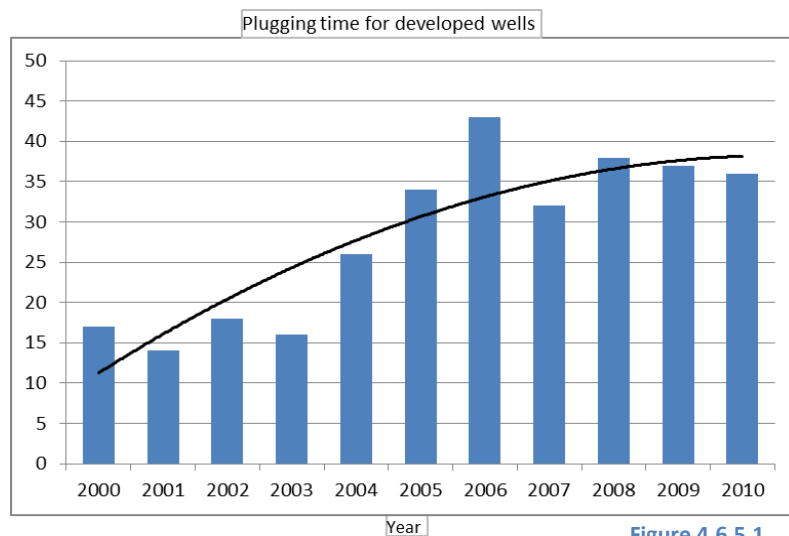


Figure 4.6.5.1

4.7. Unconventional and alternative methods for P&A

For future P&A operations, new cost effective methods and technologies are a necessity in order to ensure a continued profitable oil and gas industry. There are substantial amounts of money to be saved by reducing the time needed for P&A operations. The estimated cost for plugging 7000 wells (ref. chapter 4.5) could be as high as 1 400 billion NOK with current rig rates and methods. This is further addressed in chapter 8.1.

Perforate, Wash, Cement (PWC)

PWC is a relatively new method for P&A. The idea is to perforate the casing, wash outside the casing through these perforations and cement through the perforations in one single run. This method is substantially quicker than the standard casing pulling and casing milling approach. Time is saved because perforations penetrate the casing instantaneously and a washing tool can be applied on the same run, as well as cementing. This turns a multi-run operation into a single-run operation, saving time on milling, cutting and tripping. The issues related to swarf handling are also eliminated since little or no swarf is generated. This entire operation could be done by using coiled tubing, requiring a larger diameter coil than what is currently in use, eliminating the need to use a jack-up rig on fixed installations, or allow the use of a smaller specialized vessel on sub-sea installations. Figure 4.7.1 on the right shows how a casing can be perforated, the annuli outside the casing cleaned and cemented in only one or two runs. This method has been tested and used with great success on the Ekofisk field since late 2010. HydraWell AS estimates that their P&A tool, "HydraWash", saved the

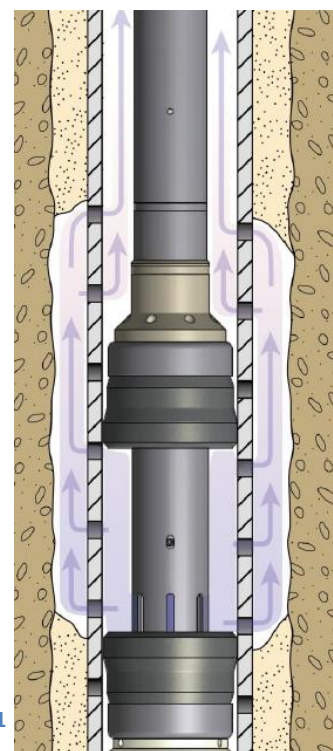


Figure 4.7.1

operator 414 rigdays and eliminated the need to handle an estimated 270 tons of swarf during the installation of 67 well barriers. [KILDE]

Better logging tools

Another challenge with current P&A methods is performing logging runs to collect data. This data is used to determine any casing damages, annuli complications, formation changes and the cement status. The problem is to be able to “see” through two or more casings. If one could see through several casings and obtain information (e.g. about the cement and/or formation in the annulus), this could save the operators from placing many unnecessary plugs. Operators would be able to determine the location of swelled shale and any old cement jobs that would be sufficient to act as barriers, resulting in less rig hours needed for P&A.

Coiled tubing

Increased use of coiled tubing is beneficial for the operators. Coiled tubing is efficient, safe and often cheaper than the conventional use of rigs for P&A. Coiled tubing can be used for many different operations, such as perforating, washing, cement squeezing, casing cutting and monitoring. Coiled tubing operations can often be conducted simultaneously with other well operations. Some wells may require a rig to do some of the operations, while coiled tubing can do the rest. Running simultaneous operations reduces the total time needed for P&A on multiple wells.

New method for casing milling

The PWC is not applicable for every situation and casing milling may be the only option for many wells. Conventional casing milling is a top-down method where the milling-tool is pushed down with the weight from the string above. Mud is continuously circulated and swarf is returned with the mud to surface. There is an ongoing joint industry project to develop so called “upward milling” as an alternative to the conventional casing milling. This upward milling generates only small and uniform swarf, and packers located above the milling tool forces the swarf to remain at the bottom of the well. This reduces the need for hole cleaning by limiting the creation of “birds-nests” from swarf, compared to conventional casing milling. Tests also show that upward milling can be performed at a very high rate of penetration, up to 18.4 m/hr (61 ft/hr). This method also eliminates the need for surface handling equipment with for swarf.

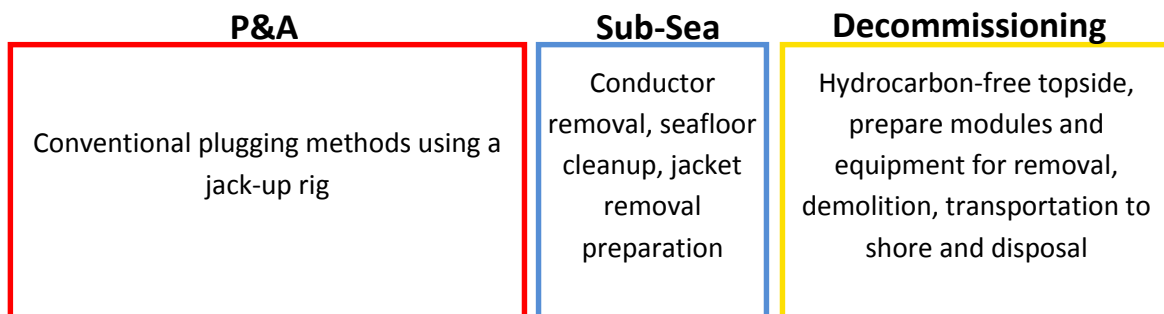
Creeping Shale

Many wells have been drilled through shale zones in order to reach the bottom hole location. Creeping shale, or shale swelling, is a phenomenon where water in the drilling mud reacts with the shale, causing it to swell. This is an unwanted situation during drilling operations, which can result in a stuck drill string. After the casing is set however, creeping/swelling shale may act as a well barrier around the casing. This well condition has been used as a way achieving a well barrier by Statoil a couple of times, with good success and significant amounts of time saved. As long as the creeping shale passes the barrier pressure test for a given well in an area, one can deduct that the shale will form a similar well barrier for surrounding wells as well. Then, only a logging run is needed for each well to confirm at least 50 m of creeping shale as a barrier.

Simultaneous operations (SIMOPS)

The various steps were often done in sequence in previous total cessation projects. By first plugging all the wells, second doing all the subsea work, and finally performing the decommissioning, sometimes even years after the last well is plugged. This requires the use of three different rigs/ships and a lot of resources both to administrate and to perform the work, making total Cessation unnecessarily costly.

Traditional way of doing total Cessation in a sequential manner:



P&A operations are the main “time consumer” in the total Cessation project, hence reducing time here is vital. In some cases, two modular rig units can work simultaneously on two separate wells in the same wellhead area. These modular rigs units are lifted into place by the cranes on a jack-up rig or on the installation, and decommissioning work can be performed in other areas on the installation while the modular rigs perform P&A activities.

Simultaneous activities increase the risk of damaging equipment, injury to personnel and contamination of the environment. Therefore, thorough risk assessments are required to make these

activities as safe as possible and clear and concise procedures for running simultaneous P&A activities are needed.

The schematic below shows an example of how decommissioning and P&A can be done simultaneously to drastically reduce rig-time. P&A is shown in red, subsea activities in blue and decommissioning in yellow.

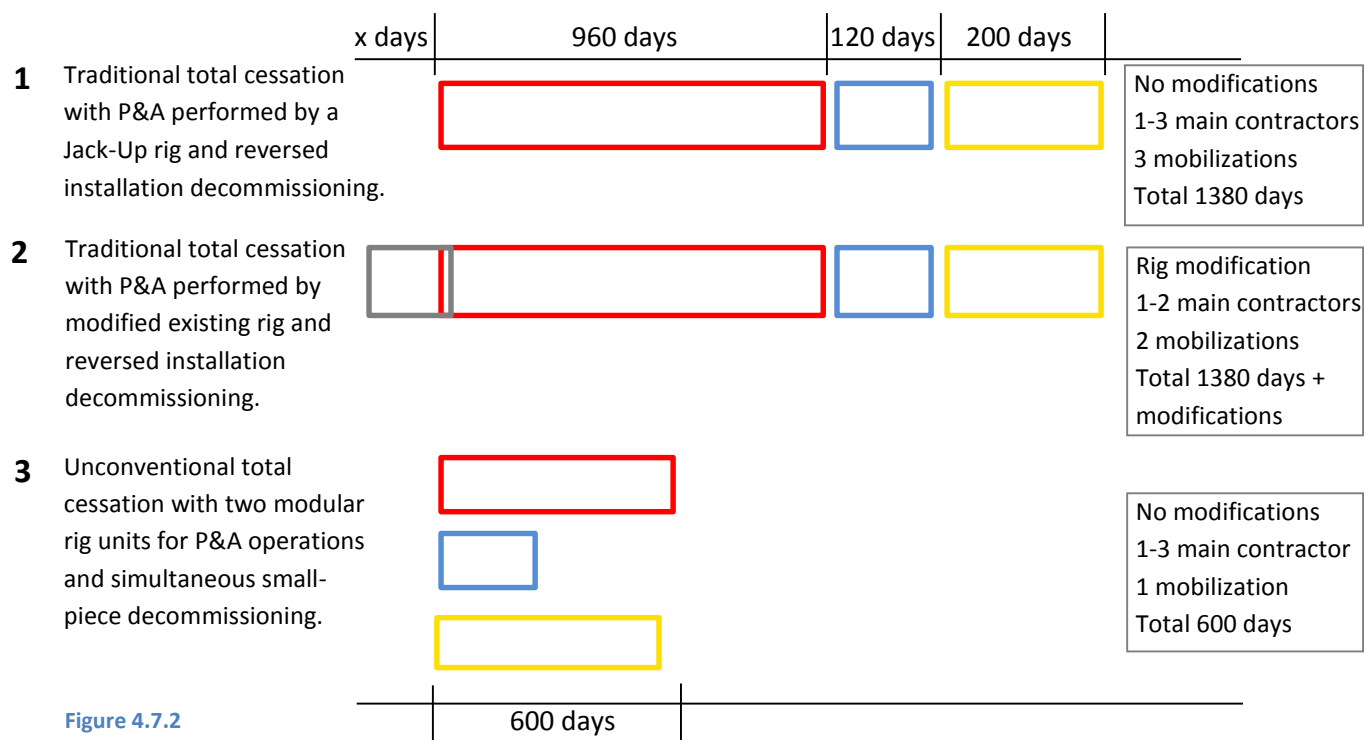


Figure 4.7.2

All-in-all, this method could reduce the rig-time needed for total Cessation on installations without a derrick, by roughly 50%.

Modular drilling rig

Modular drilling rigs (MDR) are becoming an economical attractive alternative to expensive Jack-up rigs or upgrading fixed drilling facilities. These MDRs are used on derrick-less installations like wellhead platforms or old drilling platforms where the derrick has been removed.

An MDR is a compact, lightweight drilling unit which can easily be installed and relocated. It can also use the facility's mud- and power generation system, if still in place, or be modified with its own. [19]

5. Decommissioning

The UK Offshore Operators Association (UKOOA) defines decommissioning as:

“The process which the operator of an offshore oil and gas installation goes through to plan, gain government approval and implement the removal, disposal or re-use of a structure when it is no longer needed for its current purpose.”

Decommissioning is a technical challenging task for the operator, and requires thorough planning a considerable amount of resources over a long period of time. This process is equally, perhaps even more, challenging than the field development process.

5.1. Challenges related to decommissioning

Lack of experience

Only 12 fields have shut down production on the NCS, with Frigg being the latest, in addition to individual platforms. Out of these only 6 fields with their installations have been through the entire decommissioning process including disposal. This means that there are few companies with any significant experience regarding decommissioning of installations on the NCS. Removing an installation is a very different from designing and constructing one, activities where there is extensive experience within several companies.

Physical conditions of old offshore facilities

Many old installations on the NCS show severe wear and tear due to corrosion and erosion. Also non-essential maintenance tends to be down prioritized when an installation approaches its end of life. This causes problems for decommissioning work because e.g. the support structure may have been weakened, pad-eyes are no longer useable and modules can no longer be lifted like they were designed to.



Figure 5.1.1 corroded support structure on an offshore installation [18]

Hazardous materials

Most offshore installations contain hazardous materials, which are dangerous for the surrounding environment and the personnel performing decommissioning activities. Modules built 30 - 40 years ago contain materials like asbestos which is no longer allowed to be used today.

As an example the table below shows the estimated amount of hazardous materials on an installation in the southern part of the North Sea, which is in the planning phase of decommissioning.

Material	Estimated amount (tons)
Absorbent, oil polluted	3,58
Asbestos	50,95
Batteries	1,66
Contaminated concrete	12,37
Crude oil	8,62
Debris of heavy metal contaminated paint	0,66
Diesel	9,08
Diluent, thinner	0,01
Gear, motor and lube oil	13,15
Glycol	0,06
Heavy metal contaminated debris	227,85
HG Scale from cleaning process	16,68
Hypochlorite solution	0,03
Light fittings	2,28
Mercury fluorescent tubes	0,13
NORM	1,65
Oil and zinc contaminated Mud	2,54
Oil cartridge filters	0,12
Oil with more than 15% water	8,24
Other oil waste	0,73
PCB windows	1,36
Smoke detectors radioactive	0,01
Soda lye	0,24
Spill oil	1,28
Sulfuric Acid	0,02
Sum hazardous material	363,3

Table 5.1.1 Estimated amount of hazardous materials on an offshore installation being evaluated for decommissioning [11]

Working with hazardous materials requires experienced personnel, training, proper equipment and special logistics for handling and disposal. Thorough risk assessment and planning is needed before work can be started with these materials, and every part of the demolition and disposal process

becomes more challenging when these materials are present. Asbestos has been forbidden in Norway since 1982 so only older installations will contain this material.

“Black Swan Events”

The black swan is a metaphor used in many industries to describe an unforeseen event with high impact. These are events with little or no statistical documentation and are extremely difficult to plan for. Without documentation, it is challenging to add these events into computerized simulations. In hindsight it can often be concluded that these events *could* have been expected. Data is often available, but not interpreted correctly or implemented in the relevant risks assessments and mitigation programs. Not all black swan events are necessarily negative. Taking advantage of positive unexpected events is also important.

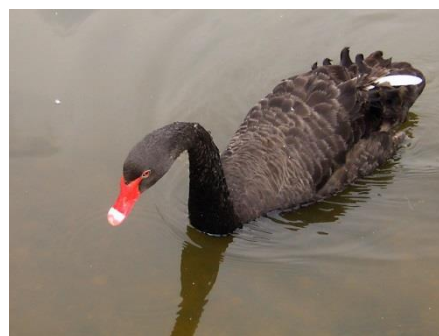


Figure 5.1.2

The best way to deal with black swan events are not to attempt to predict them, but to have sufficient robustness and flexibility in the decommissioning plan to deal with them correctly, and get the most out of the positive ones. “*Expect the unexpected, and plan for it*” is Statoil’s slogan for decommissioning. Having a plan that is easy to change “on the go” as well as efficient change management, is vital when these situations occur.

5.2. Estimated magnitude of decommissioning on the NCS

There are currently 100 fixed platforms on the NCS, 12 concrete and 88 steel-jackets. In addition there are several more or less permanently installed production, storage and offloading installations, in addition to 348 sub-sea installations. Their total estimated weight is roughly 6 900 000 tons, equivalent to 768 Eiffel towers. Table 5.2.1 shows a more detailed spread on the tonnage on different installation categories.

Type	Number	Total tonnage (1000s)
Fixed concrete installations	12	480 topside steel 4 600 concrete (support)
Fixed steel installations	88	1 000
Floating Production, Storage and offloading installations	19	750
Sub-sea installations	348	118

Figure 5.2.1 Estimate weight of offshore installations on the NCS. [12]

This is an enormous amount of concrete, steel, topside structure and hydrocarbon contaminated equipment that eventually must be decommissioned and disposed of. In addition to the existing fields, new fields are being developed with even bigger platforms and more sub-sea infrastructure.

5.3. Required new approach

Decommissioning will be the last activity the NCS in the oil and gas business and will be around as long as the industry itself. Many fields are in the late stage of their production lifetime. The current decision about what to do with the 6 900 000 tons of material of the NCS is not economically feasible. This number will most likely increase by another 50% by the time the Norwegian quest for oil is completed.

5.3.1. New planning methods

Planning for unforeseen events is crucial when performing decommissioning activities. It is difficult to foresee how the structure and installation will behave during lifting and/or demolition after having been exposed to the harsh weather conditions in the North Sea for several decades. Corrosion can weaken load bearing structures making single-lift and module based decommissioning complicated. Planning for the unexpected and structured change management process can result in huge cost and time savings. If the base plan does not work, the customer (operator) must still pay for the vessel rented to perform the decommission work. To keep any downtime costs at a minimum, backup plans must be readily available and the organization set up such that a new plan can be implemented as smoothly and efficiently as possible. This kind of planning requires a high degree of foresight and in many cases a level of pre-investment, both in time and resources.

5.3.2. Specialized vessels

A specialized vessel for decommissioning purposes, *Pieter Schelte*, is currently under construction at the South Korean shipyard Daewoo. The company who ordered the vessel is the Swiss-based company, Allseas. This vessel will specialize in removing and installing offshore installations in a single-lift operation. This will reduce the amount of required offshore work, which again will reduce both cost and HSE related risks.

The operating principle of this vessel is that specially designed hydraulic friction clamps will close around the platform legs. They are (obviously) designed to carry the total weight of the topside. The legs will then be cut below the clamps, and the topside back be lifted clear off the remaining steel jacket. This simplified single-lift operation is made possible by exploiting the integrity and strength of the platforms main support frame. The remaining steel jacket then may be disconnected from the seafloor and lifted onto the stern of the vessel and properly secured. The vessel can then transport the topside and steel jacket to shore in a single trip.



Figur 5.3.2.1 Pieter Schelte, specialized decommissioning vessel. [13]

5.3.3. Regulatory requirements

The environmental issues with leaving concrete and steel installations on the NCS are being debated. When in use, the steel jackets and concrete structures behave as artificial reefs, providing shelter and habitation for marine life. After the structures have fulfilled their useful intentional purpose, they will still act as reefs. When oil and gas related activities on the installations have ceased, the harmful impact on the area around the structure will be greatly reduced, in most cases completely eliminated. If the structures are properly cleaned, there should be no need to physically remove them from a purely environmental point of view. Much of the debate has focused around the issue of not leaving any “footprint” at the location when the industrial activity has ended. Such a view/approach can be argued, however, it can be very costly. The society must discuss if this is an appropriate use of money or if the cost associated with removing jackets could be better spent on other environmental measures.

Another issue involving regulatory requirements is to ensure that obsolete offshore structures are not limiting or causing disadvantage to merchant fishing vessels and other marine activities. As stated before, artificial reefs tend to increase the amount of fish in the surrounding area. Fishing can therefore actually improve. However, it is vital that any remaining structures are properly marked and fitted with active navigation system and lighting to avoid any dangerous situations.

6. Logistics

P&A and decommissioning activities are extremely logistic-intensive. This is mainly due to the fact that they involve huge amounts of heavy and/or hazardous materials that need to be transported to receiving facilities which are located far away from the installations where the activities take place. Many different logistic operations are required, such as vessels and rigs required to perform specific tasks at a pre-defined point in time, the need for cement and other commodities, lifting operations, support vessels for sub-sea operations, and finally transporting all the redundant materials onshore for disposal.

6.1. Marine operations on the NCS

Water depths and weather conditions are important parameters when characterizing the offshore environment. These parameters determine what type of vessel can be used for certain operations and when the weather allows those operations to take place. The North Sea is known to have severe weather conditions during the winter, making many marine operations problematic and sometimes impossible. Heavy wind and wave height are the main cause that limits marine operations.

A variety of vessels are needed for marine operations related to the oil and gas industry. Different vessels serve different purposes, and some can perform a selection of tasks. These vessels constitute a substantial financial investment, necessitating high day-rates to assure profitable margins for the investors. Some vessels are on long contracts, often in the 10-year range, in order to assure a stable and reliable income instead of a potentially higher short-term uncertain profit. For the contractors, this is a matter of risk/reward evaluation. Where some contractors take chances on short- but high cost-per-day contracts and others are more risk adverse and prefer to rely on long term contracts.

6.2. Types of vessels used for P&A of wells and decommissioning

Jack-up rigs

Jack-up rigs are a type of mobile drilling units (MODU) with a buoyant hull which enables it to be moved around to the desired locations. Tugboats are often needed to assist with the moving and positioning because jack-up rigs are usually not self-propelled. Most jack-up rigs are designed with three legs that can be lowered to support the hull of the vessel above sea level. The legs extended to the seafloor and partially penetrate the seabed. They are fitted with footings or can be attached to a pre-installed bottom mat to keep the rig stable. For P&A operations jack-up rigs are used mainly on installations without a derrick or where the original derrick has been removed, and on sub-sea installations.

Jack-up rigs can only be used in relatively shallow waters, around 120 m water depths with a few specialized jack-ups able to work at depths up to 200 m, limited by the length of the legs. These rigs can operate in almost any weather condition and are weather dependent only during relocation. Using a jack-up rig for P&A activities, while simultaneously performing decommissioning, is an option that could save time during Cessation. Jack-up rigs have large deck areas, powerful cranes and sufficient living quarters to perform such simultaneous operations. [14]



Figure 6.2.1. Typical jack-up rig with three legs. [14]

Semisubmersible rigs

At water depths beyond the reach of jack-up rigs, semisubmersible rigs are currently the only viable option for P&A on the NCS. A Sixth generation semisubmersible drilling rigs can operate at up to 3000 m water depth.

They are a type of MODU equipped with ballast tanks that are used to submerge the rig during well operations for increased stability due to reduced pitching and rolling motions, and to elevate it before and during transportation. Most semisubmersible rigs are fitted with their own propulsion system, reducing the need for tugboats. Semisubmersible rigs are mainly used for exploration drilling, drilling of subsea wells and to pre-drill wells before a fixed installation is in place. Some are also designed as floating production platforms.



Figure 6.2.2 Semisubmersible drilling rig. [14]

Mooring systems are used to keep the rig centered over its target, although severe weather conditions may force the rig to detach from the wellhead or riser, and return when the weather improves.

The use of a semisubmersible rig is one of the most expensive offshore activities, with rates as high as 3 million NOK per day for the rig alone. They are therefore seldom used for P&A activities. [14]

Drillships

Drillships are one of the least used vessels on the NCS. Rough sea makes dynamic positioning above the designated location very challenging and it is common to have to detach from the wellhead. Drillships are mostly used for well maintenance on subsea wells, but are also used during well completion work, e.g. casing and tubing installation, subsea wellhead installation and well capping.

In 2013 the world wide fleet of drillships was 80 vessels, a doubling in numbers from 2009. Technology is also advancing rapidly on drillships, increasing their capability including ice-breaking hull designs. Drillships have higher mobility than jack-up rigs and semisubmersibles, significantly reducing the transfer time between destinations. Drillships are normally not used for decommissioning activities, since they are specially designed for drilling and well-interventions. [14]

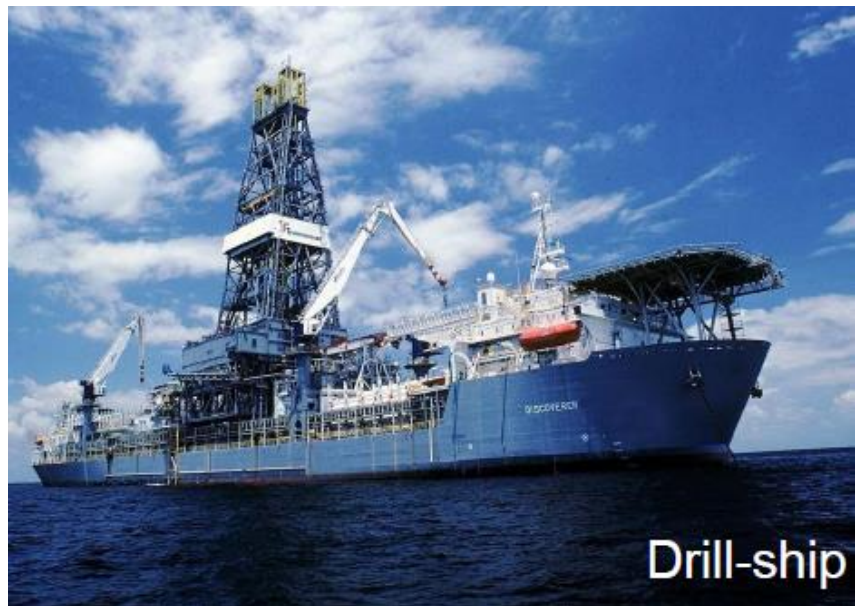


Figure 6.2.3. Drill-ship [14]

6.3. Vessels used for decommissioning of topside structures and steel jackets.

Heavy lift barges

Heavy lift barges are used for installation and decommissioning of offshore facilities. These vessels are designed with huge lifting capacities with cranes ranging from 2 000 to 14 200 metric tons and are in many cases the only option for installing facilities offshore. The SSCV (semi-submersible crane vessel) Thialf, is the largest crane vessel in the world, operated by Heerema Marine Contractors.

With its capacity of 14 200 metric tons, this vessel can be used to install and decommission facilities with very few lifts, saving valuable time. The Saipem 7000 is very similar with a capacity of 14 000 metric tons, although a higher lifting height than the Thialf. [16]

However, these giants are very expensive, close 5 million NOK per day, not including support vessels, fuel and other miscellaneous expenses.



Figure 6.3.4 The heavy-lift vessel Thialf [16]

The decision to choose a small versus a large lifting barge can be hard, and is often dictated by availability. In the current high-demand market, these lifting barges have contracts for years ahead and they operate all over the world.

Removing facilities in a single lift operation is risky not only due to the uncertainties regarding the lifting vessel itself, but largely also due to unknown weakening in the structure to be lifted from years of exposure to the harsh North Sea environment.

6.4. Disposal handling

As mentioned in 5.2., there are currently 6 900 000 tons of steel, concrete etc. to be removed and disposed of from offshore installations on the NCS. [12]

This number only covers existing installations and will therefore increase with new development projects like Utsira, Johan Sverdrup and in the Barents Sea.

There are currently only four onshore locations in Norway suited to handle material from decommissioned offshore installations.

AF Miljøbase Vats in Rogaland.

AF Miljøbase Vats is a facility that specializes in recycling and disposal of offshore installations. This location has handled approximately 60 000 tons of offshore material over the last 5 years. A total amount of 50 000 tons of materials can be stored at the facility, including 500 tons EE-products and 300 tons hazardous waste. 68 000 m² of this facility has a membrane under its paving to reduce leakage of hazardous material to the surrounding environment. The facility was significantly upgraded between 2007 and 2009 and is now licensed to handle and store radioactive materials. [14]

Aker Stord

Aker Stord began to dismantle platforms in 1996 and 30 000 tons of materials was processed here along with 36 tons of hazardous material in 2009. This facility does not have a permit to handle or store radioactive material. Aker Stord also serves as an offshore facility construction site. Aker Spitsbergen and Aker Barents, two semi-submersible drilling rigs, were commissioned here in 2009. [15]

Scandinavia Metal

Scandinavia Metal is a subcontractor of Aker Stord and is set up to receive their offshore material for sorting and recycling. The nearby facility “SIM Næring” is a disposal and waste specialist used by Scandinavia Metal and other industrial facilities in the area. Scandinavia Metal assisted with the dismantling of installations from the Frigg field, Esso Odin and Phillips Maureen. They were also awarded the contract to dismantle the Draugen FLP in 2010, weighing 4 600 tons. [15]

Lyngdal Recycling

Lyngdal is the southernmost dismantling facility in Norway and is licensed to receive offshore material for recycling, dismantling and disposal. The total available area for this facility is 561 000 m². This facility does not have the sufficient licensing to handle or store radioactive material. [15]

DNV concluded in a report to “Oljeindustriens landsforening” OLF in 2002 that the total recycling and disposal capacity in Norway was 160 000 tons of materials per year. This was a major overcapacity at the time, but many of the facilities included in that report have shut down since then.

The current available capacity is considered to be sufficient to handle the expected amount of decommissioned material for the next 5 - 10 years. When the real “boom” in decommissioning starts

in 10 - 15 years, more capacity will be required. Also, installations from the UK sector of the North Sea may be transported to Norwegian facilities for recycling and disposal, and these amounts are much more uncertain.

There are several steps involved in disposal of offshore materials, starting with the materials being transported from their original site. The schematic below shows the typical sequence of these steps.

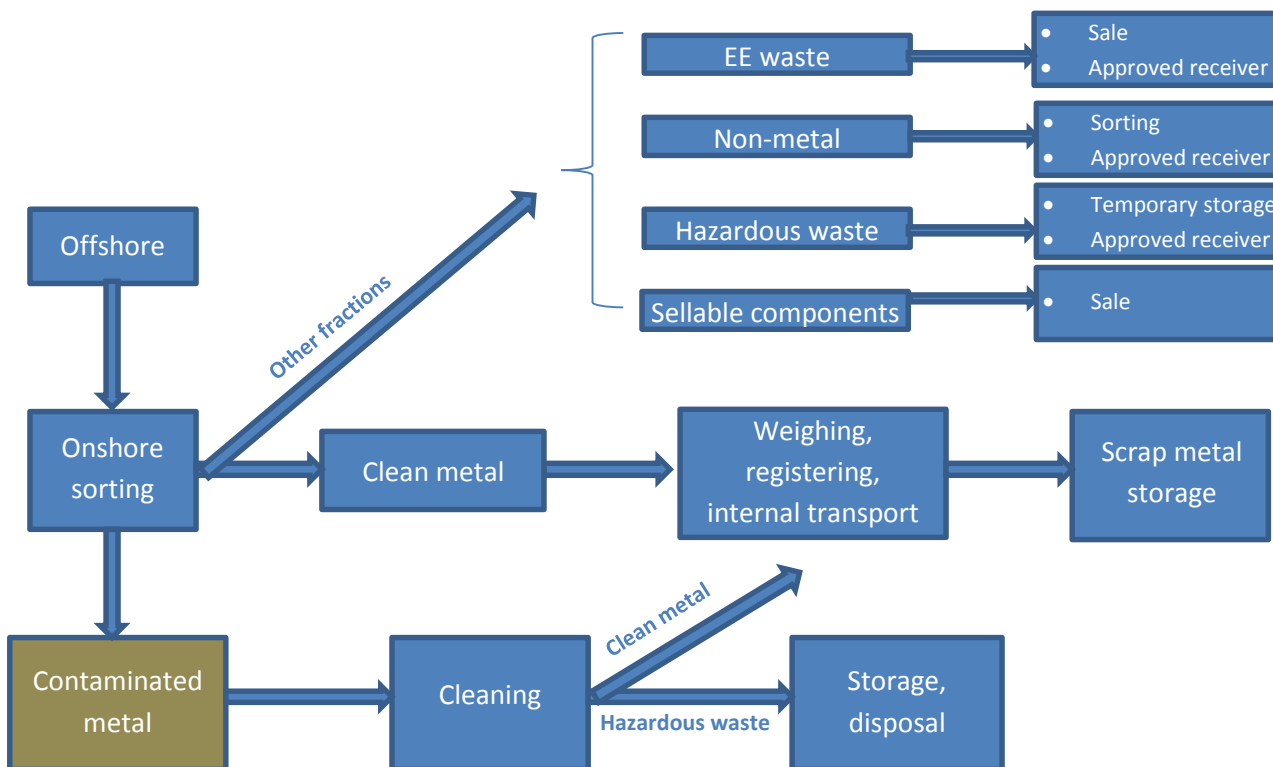


Figure 6.4.1. Disposal handling schematic, from offshore to final disposal. [14]

7. HSE – Health, Safety and Environment

The personnel safety risks involved in bringing offshore materials to shore should not be underestimated. Accidents can easily occur offshore during cutting, welding, lifting and other deconstruction activities. These risks will increase if proper cleaning has not been performed and all residual hydrocarbons have been removed. Exposure to chemicals, dust particles, gases, etc. will be an issue. And when the materials arrive onshore, the same risks apply.

Regarding environmental issues, there are many aspects to consider. Contamination to the environment from cleaning, deconstruction and debris handling can easily occur. Transporting material to shore for disposal will require substantial marine activity with a large number of vessels taking the trip to and from the installation.

The amount of energy required to completely decommission an installation is substantial. The operation releases large amounts of CO₂, NO_x and SO₂. Multiconsult AS performed a series of calculations on decommissioning and disposal of the concrete installation TCP2 on the Frigg-field. According to these calculations, 673 000 Gigajoule of energy was needed resulting in the release of 55 000 tons CO₂, 750 tons NO_x and 205 tons SO₂. [17] For comparison, the total emissions on the NCS were 12.3 million tons CO₂, 50 000 tons NO_x and 800 tons SO₂ in 2012.

When the material arrives onshore, an additional set of environmental issues must be addressed. The location of the receiving site itself can cause conflict with nearby activities, such as fish farms, leisure areas, wildlife, local society, etc. Many of these will not appreciate a large scale industrial operation in their neighborhood causing noise, increased heavy traffic, etc. In addition to these “inconveniences” come the less tangible problems related to the hazardous materials potentially leaking to the air, water and soil.

8. Economics

Operators have to address and estimate the cost associated with future P&A of wells and decommissioning of the installation(s), already during the field development planning stage. Operators are required to allocate resources for this task. Abandoning an offshore well can be in the 20-200 million NOK range, more costly for subsea wells where a drilling vessel is needed. Abandoning a well in the North Sea is less expensive on the UK side. There the cost ranges from about 5 to 10 million NOK per well with P&A from a fixed installation, and up to 30 to 45 million from a jack-up, semisubmersible or dynamically positioned floating drilling unit. The cost on the Norwegian side is significantly higher both due to regulators' requirements and the operators' self-imposed standards.

8.1. Cost of P&A

The total cost for P&A is mainly determined by two variables

- The daily cost to rent and operate a rig.
- The number of days required to complete the job.

P&A can be performed in mainly 3 different ways:

1. P&A from a fixed installation
2. P&A from a Drilling Support Vessel (DSV)
3. P&A from a jack-up rig or semi-submersible

Plugging and abandonment from a fixed platform is the cheapest alternative, but is often not possible due to a lack of derrick. A price range of 1 – 1.5 million NOK per day for well activities is not uncommon, resulting in 30 - 45 million NOK per well (assuming a plugging time of 30 days, which is a fairly low estimate).

P&A from a DSV is a more expensive option at around 2 - 3 million NOK per day, resulting in 60 - 90 million NOK per well. The operation from these vessels can also be delayed due to severe weather conditions that are not uncommon in the North Sea, resulting in downtime and additional costs.

P&A from a semi-submersible or jack-up rig is the most expensive alternative at around 3.5 – 6 million NOK per day, resulting in 105 - 180 million NOK per well.

These costs include both the daily rig rate and overhead cost. Overhead cost is expenses associated with operating the rig. This cost is usually about the same as the rig rate, which only covers direct rig lease.

There are currently nine jack-up rigs active in the Norwegian sector, with seven more in construction and one in yard for major overhaul. With the already high demand for these rigs, there is a distinct possibility for a conflict of interest between P&A and drilling new wells. When a jack-up rig is performing P&A activities instead of drilling a new well, the effective cost of the P&A work is higher due to the delayed production from that new well that could have been drilled instead. This lost income is normally not considered as a P&A cost.

Introduction of new methods and technology could reduce the number of days required to perform P&A, although the daily cost for the rig would remain the same. The rig rate is governed by the competition in the market, and with the rising demand for vessels, it will be difficult to obtain any lower rate. At present there is too little competition in this part of the business. Seadrill, Mearsk and Rowan are basically the only contractors that supply jack-up rigs needed for many of the P&A and decommission operations. Semi-submersible available from other contractors, can only plug and abandon subsea wells.

Some rigs rates have increased by 500 000 NOK per day compared to 3 years ago. This is a huge increase in cost and is can be expected to keep rising with increased demand for P&A in the future. Rigs are costly investments for the contractor companies and require high rates to secure their investments. Rigs are in great demand due to the current high oil price, which allows the contractor companies to maintain their high rig rates.

To get an indicative estimate on the cost for the 7 000 wells that are premised to be plugged on the NCS in the future, some assumptions have been made.

Assumption 1: Each well needs 30-60 days to be plugged with current technology and methods.

Assumption 2: Vessels/rigs used are spread between on-rig derrick, semi-sub, drill support vessel and jack-up rig, giving and **average** cost of operation of 2.5 – 4.5 million NOK per day (rigrate + overhead).

Table 8.1.1. below shows the estimated P&A cost for 7 000 wells using the spread in assumptions 1 and 2 above.

# Wells		7 000
Cost/day	kr	2,5
Days/well		30
Total cost	kr	525 000

# Wells		7 000
Cost/day	kr	3,3
Days/well		45
Total cost	kr	1 039 500

# Wells		7 000
Cost/day	kr	4,5
Days/well		60
Total cost	kr	1 890 000

Table 8.1.1 Estimated total cost in million NOK for P&A of 7 000 wells using average rig rates (on derrick rig – jack-up rig) and a range of days required.

For comparison, 1 890 billion NOK is almost 1.5 times the entire Norwegian national budget for 2014.

These three estimates range from the optimistic side to the pessimistic side of the scale. Spending an average of only 30 days per well for the remaining 7 000 wells will require both new methods and new technology in order to achieve this kind of sustainable efficiency. Simultaneous operations with two small modular rigs performing P&A activities is most likely the easiest way to reduce P&A time, where this method can be applied.

8.2. Cost of decommissioning

Statoil operates with an estimated average cost of decommissioning of 50 - 70 thousand NOK per ton to be removed. Excluding the concrete support structures, decommissioning the remaining ca. 500 installations on the NCS, weighing roughly 2.3 million tons, can therefore be estimated to cost between 115 and 160 billion NOK. Very limited decommissioning has actually been performed, making the future cost of this relatively uncertain. The cost will vary with the general cost-development in the industry, the supply and demand in the market and the handling capacity at the onshore receiving facilities. Unforeseen events like new regulations may increase the total cost and new methods and more efficient vessels may lower them.

The large Condeep platforms are at present not required to be totally decommissioned. A change in regulations could, however, require an additional 4.7 million tons of concrete to be removed from the NCS and disposed of onshore. Leaving them in place is the best solution, from a purely economic standpoint. Operators would also prefer to leave the steel-jacket, topside and subsea installations in place, and only remove hazardous materials including residue hydrocarbons. The industry argues that the installations can act as artificial reefs which would increase the marine life and diversity in the surrounding area. These installations would then be fitted with navigation equipment and lighting, making them easy to avoid for marine traffic.

The main cost of decommissioning is the work that takes place offshore. The biggest part is for renting either a heavy lift barge for single-lift or module-wise removal, or a jack-up rig for small-piece decommission and removal for a longer period of time, and the labor wages for offshore personnel. AF Decom VATS estimates that the price to dismantle steel etc. for sorting, disposal and recycling at their onshore facility is 500 NOK per ton, which is roughly only 1% of the total decommissioning cost.

8.3. Hidden cost

A cost that is not always accounted for is the negative effect on the net present value (NPV) of postponed production. Performing P&A in the coming years may easily come in conflict with drilling of new development wells or maintaining existing production wells. Having an estimated 10 rigs on

average continuously performing P&A work for the next 57 years (ref chapter 4.5), means 10 fewer rigs to drill new wells or maintain existing ones, in order to help reduce decline in production. The value of oil produced today is higher than the same amount of oil produced later in time, according to the formula for NPV.

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

Where:

R_t – is the cash flow at a given time t .

i – is the discount rate, which expected rate of return in the financial market with similar risk.

t – is the time of the cash flow.

Using this formula, one can prove that prioritizing to plug a well instead of drilling a new one, there is an added cost of postponed production in addition to the actual cost of the plugging work.

Total production on the NCS for 2014 is estimated to be 1.46 million barrels per day. With the current 3000 production/injection wells, this equals to approximately 180 000 barrels of oil per well per year.

The difference in NPV between producing 180 000 barrels this year or next year is:

$$\begin{aligned} & \frac{R_1}{(1+0.1)^1} - \frac{R_0}{(1+0.1)^0} \\ & \frac{180\,000 \text{ barrels} \times \frac{110\$}{\text{barrel}}}{(1+0.1)^1} - \frac{180\,000 \text{ barrels} \times \frac{110\$}{\text{barrel}}}{(1+0.1)^0} \\ & \underline{\underline{= -1\,800\,000\$}} \end{aligned}$$

Postponing one new production/injection well for 1 year potentially reduces the income by 1.8 million \$ or 10.8 million NOK.

8.4. Value of postponing expenses

NPV calculations also show that it can be justified to postpone a cessation project as long as possible because an expense next year has a lower NPV than the expense today. This is shown by following the same equation as in 8.3.

Postponing a one billion NOK Cessation project (that numerous previous cessation projects have exceeded) by one year, reduces the “effective” cost of that expense (NPV) by almost 10% (depending on the discount rate).

$$NPV = \frac{1000 \text{ mill.}}{(1 + 0,1)^1} = 909 \text{ mill.}$$

Although NPV calculations are not 100% applicable to every situation because it does not account for rising project costs, inflation, risks associated with project postponement, predicting the discount rate, etc., it is obvious that postponing an expense that has no associated income, has financial benefits. This is an incentive for operators to postpone Cessation.

9. Total Cessation - an example

TOR 2/4 E located in the southern part on the NCS, 13 km North-East of the Ekofisk Complex, is reaching its end of life and is planned to be shut down in 2015. Modifications required to maintain the facility at an acceptable standard are more costly than the current production justifies. The operator of TOR 2/4 E is ConocoPhillips Norway and the installation was originally a combined drilling, wellhead, processing and accommodation rig.

ConocoPhillips is currently in the planning phase for the Cessation work, expecting to tender for bids later this year.

Operator	ConocoPhillips Norway
Installation type	Fixed, steel-jacket, module based.
Dry weight	6348 tons
Number of modules	7
Number of wells	16
Derrick	Removed
Production June 2014	3 500 BOE/d

9.1. Total Cessation with conventional methods

Total Cessation of TOR 2/4 E done with conventional methods in 3 separate steps.

1. A jack-up to perform P&A operations, since there is no derrick on the platform.
2. A ROV support vessel for Sub-Sea operations, like jacket cleaning, debris removal, pipe cutting and in some cases to assist in conductor removal with digging and cutting.
3. Decommissioning and platform removal is the final step, using a heavy lift barge for this task. TOR 2/4 E was installed in 1978 and was commissioned as a module-based platform. The jacket was installed first followed by seven modules individually installed and welded in place. The platform was not designed for one-piece removal and thus the conventional method for removal will have to be a reverse installation, by removing the modules in the opposite order of how they were installed. This operation will require at least eight heavy lift operations, potentially each with time consuming round-trips to an onshore disposal facility.

Rough cost estimate:

1. 16 wells with an estimated 45 days per well for P&A from a Jack-Up rig, costing 5 million NOK/day (including cost of crew, management, equipment and rig rent).
 - Total: 3.6 billion NOK.
2. Estimated 4 months of sub-sea operations from ROV support vessel, costing 1.5 million NOK/day.
 - Total: 180 million NOK.
3. Decommissioning cost is estimated based on the gross tons to be removed, averaging at 50 thousand NOK per ton.
 - Total: 320 million NOK.

The total cost of Cessation of TOR 2/4 E, based on the above, can be estimated to 4.1 billion NOK when using conventional methods.

9.2. Alternative method for total Cessation

An alternative method to perform total Cessation on TOR 2/4 E is to do all steps mentioned in 9.1 simultaneously. The only vessels needed then would be a jack-up rig and an assisting supply vessel, which would also be used in the conventional method.

1. Two P&A operations could be run simultaneously from two separate modular rigs, lifted in place by the supporting Jack-Up rig. The modular rigs are small enough to fit both of them on the deck above the wellhead area, reducing the total P&A time by 40-45%. Improved plugging methods like PWC could further decrease plugging time by another 25%.
2. ROV's would be needed, but the sub-sea operations could run from the Jack-Up rig already in place, eliminating the need for a ROV support vessel and greatly reduce cost.
3. Decommissioning would be done by small-piece removal with temporary storage on the supporting Jack-Up rig before being sent to an onshore disposal facility by use of supply vessels. The steel jacket is the only piece that would require a heavy lift barge for removal.

Rough cost estimate:

1. 16 wells with an estimated 25 days per well (using PWC) from two modular rigs, supported by a Jack-Up rig, costing 8 million NOK/day, this includes cost of crew, management, equipment, modular rigs and rent.
 - Total: 1.9 Billion NOK.
2. Estimated 4 months of sub-sea operation with ROV vessels handled by the Jack-up rig and operated at an onshore location, costing 500 thousand NOK /day.
 - Total: 60 million NOK.

3. Decommissioning cost is estimated by AF Decom (See reference: Ekofisk TOR 2/4 E Decommissioning Feasibility Study – “Piece Small” concurrent to Well P&A) to be 170 million NOK. This is excluding the steel jacket weighing 1020 tons which can be estimated to cost 50 thousand NOK per ton to remove.
 - Total: 220 million NOK.

The total cost of cessation of TOR 2/4 E can be estimated to 2.2 billion NOK when using unconventional methods and PWC technology.

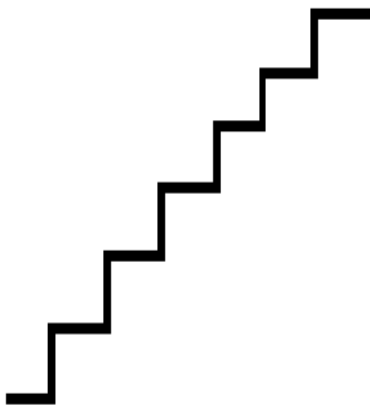
10. Discussion

The industry needs to change the way Cessation is conducted. Following the same cost-growth as the last decade will result in too great expenses for the operators and a major income loss for the Norwegian government in the form of reduced tax-income and cancellation or postponement of new development projects.

The changes needed for cost reduction can be achieved by small incremental changes or larger step changes.

10.1. Small incremental changes

Incremental changes are small changes that take place gradually over a period of time. Examples of this are;



- Increasing experience
- Improved materials
 - Better cement or other compositions of materials with faster setting-time
- Improved equipment
 - Better cutting tools
 - Better milling tools
 - Better handling tools
- Increased competition in the market resulting in lower rig-rates

Increasing experience makes every individual operation more efficient. However, it takes time to achieve this experience and there are limited ways of gaining experience without actually performing P&A and decommissioning. Experience from other parts of the world, e.g. Gulf of Mexico, cannot be automatically transferred to NCS with the different environmental conditions as well as regulatory requirements. This experience must therefore be obtained by companies operating on the NCS.

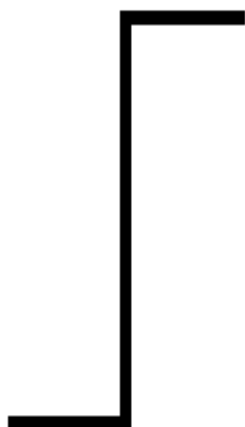
Improving materials is a constantly ongoing exercise, taking place all over the world and not only in the oil and gas industry. Advances in material technology in for instance in the onshore construction industry, will also benefit the Cessation projects. However, for P&A purposes, for the time being one will have to rely on spin-off effects from other applications.

New and improved equipment for all aspects of Cessation is mainly driven by the suppliers more than the customers/operators. Better tools will give a supplier a competitive advantage either by enabling a faster, more efficient or safer execution of the work. This will be a natural development in the industry, which will take time, unless a sudden breakthrough in technology occurs. However, the operators can speed up this process by funding, supporting or requesting a specific improvement or functionality.

Regarding rig-rates and other operational expenses, where there is a limited supply and increasing demand, there will always be a demand vs supply relationship. Limited supply combined with high demand, will result in high rates. However, high rates will also promote increased supply, but can also result in reduced demand. This is an ongoing everlasting balancing act. With the foreseen increase in Cessation activities, it is expected that new suppliers and/or rigs will become available. High oil prices can shift the demand of these rigs over to development projects. Low oil prices will make these rigs available for Cessation projects.

10.2. Larger step changes

Step-wise changes are changes with greater impact that occur almost instantaneous or within a short period of time. Examples of this are;



- New technology and techniques
 - PWC
 - Take advantage of shale swelling
- New planning and execution methods
 - Increased use of simultaneous operations
 - Specialized total Cessation suppliers/companies
- New specialized P&A rigs and decommissioning vessels.
 - Modular rigs, two simultaneous P&A operations
 - One-lift decommissioning vessel (Allseas)
- New rules and regulations

New techniques and methods are being developed several companies, both operators and suppliers. As discussed before, total Cessation is a fairly new activity in the oil and gas industry. Not much time or resources has been spent on improving or optimizing the way Cessation is performed. With the increasing activity level in this field, efforts have also increased. With the obvious magnitude of these future tasks, the “size of the price”, it is just a matter of time before significant breakthroughs can be

expected. Considering the immaturity of Cessation activities, it will not take much investment in improvements to achieve significant rewards. And when these first improvements in techniques and methods appear, they will have the largest impact since the potential for improvement is so big. As time goes by and Cessation matures and has improved, the additional improvements will most likely resemble small incremental changes (see previous chapter).

Most companies on the NCS, both operators and contractors, have good experience with planning and executing development or modification projects. And although a total Cessation project follows steps similar to development projects, there are fundamental differences. These differences can cause delays and inefficient execution. Starting with estimating duration and cost of activities during the planning phase, submitting thorough applications to the authorities in a correct manner at the right time, being prepared for unforeseen events, handling the unexpected, all these parts of the project will be easier to address with increased experience and knowledge. Companies with this experience and knowledge will have a competitive advantage as well as being able to perform the work faster/cheaper. And with such competitive advantage, they will most likely attract more business, thereby gaining even more experience and knowledge. There is room for specialized companies providing this kind of service and it can be a matter of "the winner(s) takes it all". Areas where the operator can contribute are mainly related to simultaneous operations. It is the responsibility of the operator to establish concise and prudent procedures that opens for safe and efficient execution of multiple activities on their installations.

New type rigs and vessels are costly investments for a contracting company. They can be built on speculation, meaning there is no definite customer or clearly defined demand, but this not normal and usually only done by companies with a strong financial base. Customers (operators) are equally reluctant to commit to a future contract for a rig or vessel that has not been built yet. Those contracting companies who are willing to, or large enough to, risk building rigs or vessels that will be required in the future, stand to gain by achieving a competitive edge in the market. As with other new developments, it is a question of seeing into the future and accurately judging what will be demanded by the customers. The main difference when it comes to Cessation rigs and vessels, are that they are so huge, costly and specialized. In the best case, it will take many years to make a return on the huge investment. And if the predictions are wrong, the economic losses are equally huge and can bankrupt the company.

It is obvious that different rules and regulations in different countries has an impact on how Cessation is conducted. This relates to both the way expenses are handled regarding taxation and also the specific requirements set forth by the authorities when it comes to the extent of required decommissioning. In Norway, operating expenses and investments are tax-deductible. There are specific rules for how future expenses, e.g. Cessation, can be deducted from current income. If Cessation is postponed as long as possible, there could be insufficient income for the operator to pay for these activities. Or, the operator would be in such a financial position that all income during the last year of operation would only pay for Cessation, hence no income-tax to the government. It is in everyone's interest to establish a system where it is possible to allocate funds from current revenues

to pay for future Cessation costs. This will create a much more stable and predictive economic environment, allowing both the operator and the Norwegian government better financial planning. When it comes to specific requirements regarding the extent of decommissioning of installations, the current policy is strongly influenced by environmental issues. In many countries, leaving installations in place to act as artificial reefs (“rigs-to-reefs”) can be a prudent way of disposal. This has both advantages and potential negative effects, but should be addressed in a sober and objective manner and subjected to a structured cost-benefit analysis. New techniques can become available as well as methods for monitoring any negative effects, making this a viable alternative also on the NCS. On the other hand, new more strict regulations and/or new removal techniques could enforce the complete removal of also concrete installations. This would significantly increase the total cost of Cessation on the NCS.

11. Conclusion

Total Cessation is a time consuming and costly activity for any operator company. It will also consume a lot the tax-income to the government in the near to long term future. However, Cessation is necessary to ensure that the oil and gas industry leaves as small environmental footprint as possible. P&A can be justified to be required on every well, although the need for total decommissioning and removal of installations is debatable both from an environmental and cost-benefit point of view. There is, a large amount of work that needs to be done in this area during the next 5 - 30 years with many fields reaching their end of life and several thousand wells requiring P&A. With today's technology and methods for performing P&A and decommissioning, the price for total Cessation on all existing and future wells and existing installations on the NCS, could be more than 2 000 billion NOK (worst case P&A 1 890 billion NOK + decommissioning 160 billion NOK).

New methods and technology are urgently needed and can potentially save billions for the Norwegian society and the operators.

Some main conclusions from this paper:

- The main bulk of total Cessation cost is P&A activities, which accounts for 75-85% of the cost. This is mainly because it requires the most rig time, which is extremely expensive, and is often subjected to unforeseen events like problematic well conditions and bad cement jobs when the well was developed.
- New technology and techniques to reduce rig-time for P&A is needed, and considerably more resources should be assigned to R&D in this area. The current conventional methods are slow, inefficient and generate secondary challenges like swarf (see 4.6.2).
- The PCW method (see 4.7) shows great potential and has been used on installations in the Ekofisk area with good results and in some cases reduced the plug-setting time by 50%.
- New methods for logging through several casings, combined with techniques to qualify creeping shale as a well barrier, may eliminate the need to set multiple annuli well barriers.
- Simultaneous P&A operations from two modular rigs should be used where this is applicable, thereby potentially reducing time needed for a P&A campaign by close to 50%.
- Simultaneous operations regarding P&A and decommissioning should be used where this is feasible. Performing small-piece decommissioning and sub-sea operations conduction

P&A activities with a modular rig or jack-up rig, reduces the total time needed for Cessation. (See figure 4.7.2)

- The OSPAR convention should be evaluated and possibly revised, with the aim to consider leaving fixed installations in place offshore and limit decommissioning to removal of hazardous materials like asbestos and residual hydrocarbons and install navigational equipment to avoid complications with marine traffic. This could eliminate a large portion of the cost related to decommissioning which, is estimated to be between 115 and 160 billion NOK for the existing installations.
- Operating companies should address cessation issues now and not wait until it is absolutely necessary. Postponing the critical questions related to the technical and economic challenges may seem to be a sound approach from a purely financial point of view (ref NPV). However, the problems will not disappear and the final cost will not go down, unless these issues receive the proper attention.
- The technical issues are a joint challenge for the authorities, the operating companies and the suppliers. Therefore it must be a joint effort to allocate the necessary funds to address them. A relatively small investment now, can reap huge dividends later.

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[18] 2014 Axiom NDT and Offshore Services, showing corrosion on offshore support structure. <http://www.axiomndt.co.uk/services/close-visual-inspection-cvi-of-welds/>

[19] Archer The well company, Emerald modular drilling rig. <http://www.archerwell.com/page/251/modular-rigs.htm>

Attachment 1 – Average rig rates [5]

This list contains all the active Jack-up rigs, semi-sub rigs and drill ships and their average rate in the Norwegian section of the North Sea May 2014 and January 2011. Some rigs are on the same contract as they were in 2011 and some are on new contracts.

Rigg name	Type	Owner	Rate 2011	Rate 2014
Bideord Dolphin	Semi-Sub	Dolphin Drilling	USD \$418 000	USD \$474 000
Borgland Dolphin	Semi-Sub	Dolphin Drilling	USD \$537 000	USD \$525 000
Bredford Dolphin	Semi-Sub	Dolphin Drilling	USD \$333 000	USD \$442 000
COSLInnovator	Semi-Sub	COSL Drilling	-	USD \$335 000
COSLPioneer	Semi-Sub	COSL Drilling	USD \$320 000	USD \$420 000
COSLPromoter	Semi-Sub	COSL Drilling	-	USD \$335 000
Deepsea Atlantic	Semi-Sub	Odfjell Drilling	USD \$490 000	USD \$490 000
Deepsea Bergen	Semi-Sub	Odfjell Drilling	USD \$320 000	USD \$339 000
Island Innovator	Semi-Sub	Marac	Private	Private
Leiv Eriksson	Semi-Sub	Ocean Rig	USD \$530 000	USD \$545 000
Maersk Giant	Jack-Up	Maersk Drilling	Private	Private
Maersk Guardian	Jack-Up	Maersk Drilling	Private	Private
Maersk Innovator	Jack-Up	Maersk Drilling	Private	Private
Maersk Inspirer	Jack-Up	Maersk Drilling	Private	Private
Maersk Reacher	Jack-Up	Maersk Drilling	Private	Private
Ocean Vanguard	Semi-Sub	Diamond Offshore	USD \$354 200	USD \$450 000
Rowan Norway	Jack-Up	Rowan Drilling	USD \$250 000	USD \$350 000
Scarabeo 5	Semi-Sub	Saipem	USD \$420 000	USD \$494 000
Scarabeo 8	Semi-Sub	Saipem	-	USD \$460 000
Songa Dee	Semi-Sub	Songa	USD \$423 000	USD \$423 000
Songa Delta	Semi-Sub	Songa	USD \$448 000	USD \$448 000
Songa Trym	Semi-Sub	Songa	USD \$365 000	USD \$365 000
Stena Don	Semi-Sub	Stena Drilling	USD \$400 000	USD \$495 000
Transocean Artic	Semi-Sub	Transocean	USD \$299 000	USD \$415 000
Transocean Barents	Semi-Sub	Transocean	USD \$561 000	USD \$601 000
Transocean Leader	Semi-Sub	Transocean	USD \$409 000	USD \$409 000
Transocean Searcher	Semi-Sub	Transocean	USD \$434 000	USD \$394 000
Transocean Spitsbergen	Semi-Sub	Transocean	USD \$500 000	USD \$542 000
Transocean Winner	Semi-Sub	Transocean	USD \$487 000	USD \$461 000
West Alpha	Semi-Sub	Seadrill	USD \$501 000	USD \$532 000
West Elara	Jack-Up	Seadrill	USD \$371 000	USD \$371 000
West Epsilon	Jack-Up	Seadrill	USD \$293 000	USD \$294 000
West Hercules	Semi-Sub	Seadrill	USD \$495 000	USD \$507 000
West Linus	Jack-Up	Seadrill	USD \$361 000	USD \$361 000
West Navigator	Drill Ship	Seadrill	USD \$620 000	USD \$609 000
West Venture	Semi-Sub	Seadrill	USD \$451 000	USD \$451 000
Average			USD \$417 333	USD \$444 867