Faculty of Science and Technology

MASTER'S THESIS

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Abstract

There are thousands of subsea wells in the world. The subsea industry is growing, more and more subsea wells are being developed. When the wells are no longer used, usually because they become unproductive, they need to be permanently plugged and abandoned (P&A). The regulations order the oil and gas industry to seal the unused wells to protect the environment. In the next few years, many of those subsea wells are expected to reach their 'unproductive phase', which means there will be a considerable number of subsea wells to be abandoned.

For the last couple of years, lots of investment has been spent in the development of new technologies dedicated to well P&A. However, the current method of P&A operation is still traditionally performed with the same tools that are used for drilling and completions. This expensive way of operation raises up companies' costs and the time to P&A a well. The market remains dominated by the use of conventional solutions, such as full capacity drilling rigs. This method indeed makes sure the whole operation can be done safely but it is a less cost-effective solution. Furthermore, P&A activity has no value creation. Therefore, alternatives methods are necessary. One of the alternatives is to use a monohull light well intervention (LWI) vessel, which has a significantly lower cost, to replace the rig for the entire P&A operation.

In this thesis, the challenges of performing P&A using LWI vessel are described. Several concepts of solutions are presented, with alternative methods and new technologies that can be used in qualifying LWI vessel P&A operation. There exists a great potential in moving the conventional method from using rig into smaller and cheaper LWI vessel. However, most of the technologies described in this thesis are still in a conceptual stage. Thus, comprehensive qualifications and extensive field trials are needed.

The P&A operation utilizing LWI vessel that is discussed in this thesis can be divided into two methods; riserless and riser based method. Presently, the better option for P&A activity using LWI vessel is to use a riser and utilizing coiled tubing for the operation. Modifications of the vessel with some additional equipment might be needed to satisfy the operational requirements. The riserless operation could become the best option after the technology is qualified through considerable field trials. Therefore, companies' involvement is now needed to test the new technology and to make concrete steps in order to change the mindset of traditional P&A operation.

Acknowledgment

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Abbreviations

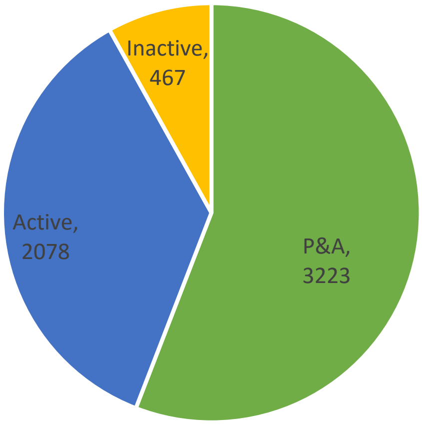
BHA	Bottom Hole Assembly
BOP	Blow Out Preventer
BSEE	Bureau of Safety and Environmental Enforcement
DDS	Dual Drill String
DHSV	Down Hole Safety Valve
DP	Dynamic Positioning
EAC	Element Acceptance Criteria
EDP	Emergency Disconnect Package
ESP	Electrical Submersible Pump
HPU	Hydraulic Pressure Unit
IOR	Increased Oil Recovery
LLP	Lower Lubricator Package
LMRP	Lower Marine Riser Package
LOT	Leak Off Test
LRP	Lower Riser Package
LS	Lubrication Section
LT	Lubricator Tubular
LWI	Light Well intervention
LWIRS	Light Well Intervention Riser System
MD	Measured Depth
NCS	Norwegian Continental Shelf
NORSOK	Norwegian Petroleum Industry Standard
P&A	Plug and Abandonment
PCH	Pressure Control Head
PSA	Petroleum Safety Authority
PWC	Perforate, Wash, and Cement
RDM	Reelwell Drilling Method
RLWI	Riserless Light Well Intervention
ROV	Remote Operated Vehicle
SCM	Subsea Control Modules
SCSSV	Surface Controlled Subsurface Safety Valve
SFSH	Submerged Flow and Safety Head
SSR	Self-Standing Riser
SWAT	Suspended Well Abandonment Tool

TCP	Tubing Conveyed Perforating
TOC	Top of Cement
UKCS	UK Continental Shelf
ULP	Upper Lubricator Package
WASP	Well Abandonment Straddle Packer
WBE	Well Barrier Element
WBEAC	Well Barrier Element Acceptance Criteria
WBS	Well Barrier Schematic
WCP	Well Control Package
WOC	Waiting on Cement

1. Introduction

1.1. Background

Every well drilled, whether in onshore or offshore, platform or subsea, eventually has to be decommissioned at some time. The term used for the well decommissioning activity is plug and abandonment, or P&A. P&A is the process in which a well is closed permanently. P&A is solely driven by the economics. When the operating expenses are higher than the operating incomes, then it is time to abandon a well. Other than that, the governments and legislative authorities are also mandating the oil and gas industry to seal and permanently abandoned unproductive wells to prevent them from impacting the environment.



- P&A
  - Permanently plugged and abandoned
- Active
  - Producing
  - Drilling
- Inactive
  - Temporary abandoned
  - Reservoir abandoned
  - Permanently plugged (not abandoned)
  - Suspended
  - Not entered

Figure 1-1 Status Distribution of Wellbores on the NCS [1]

There are a lot of wells to be plugged and abandoned. It is estimated that 12,000 wells in the Gulf of Mexico are qualified as P&A candidates. In the UK sector of the North Sea, there are about 3,000 wells that are scheduled for permanent abandonment in the near future. According to Spieler & Øia in their presentation in Norwegian P&A Seminar 2015 [1], on the Norwegian Continental Shelf (NCS), from 5,768 total of wellbores, there are 467 inactive wells and 2,078 active wells, resulting 2,545 wells that need to be plugged and abandoned at some point as illustrated in Figure 1-1. Moreover, within the 'inactive' category, there are 352 wells that are ready to be plugged and abandoned at the present time, with 220 are platform wells and 130 are subsea wells. Those data show that presently, there is a 'wave of wells' needing to be permanently plugged and abandoned. It is expected to increase rapidly in the next 20 – 30 years.

P&A is a very expensive operation. In Norwegian P&A Seminar in 2014, Martin Straume, leader of the Norwegian Oil & Gas P&A Forum, presented a time estimation of the P&A activity on the

NCS. Based on the number of 3,000 wells to be plugged, with 15 rigs sets for full-time P&A operation, along with 35 days average of time to plug each well, it will take approximately 20 years to plug them. Furthermore, based on the last ten years activity, there are around 144 new wells drilled every year, meaning that another 2,880 wells would have been drilled during this period. It means that with 15 rigs it would take approximately 40 years to plug all of the wells. Assuming the current method and technology of P&A is used, the cost could be as much as 876 billion NOK [2].

On this background, currently, there is a large focus in the industry to reduce the cost of P&A operations. Figure 1-2 shows the comparison of well intervention cost using different techniques. It was Statoil's Increased Oil Recovery (IOR) activities that even though the cost will not be the same as P&A activity, it can illustrate a relative cost comparison between onshore wells, offshore platform wells, and offshore subsea wells. The focus of this thesis is on subsea wells. It can be seen from the figure that the cost of intervention using a rig is much higher than using a vessel. Therefore, the future goal is to be able to use a light well intervention (LWI) vessel to perform the entire P&A operation.

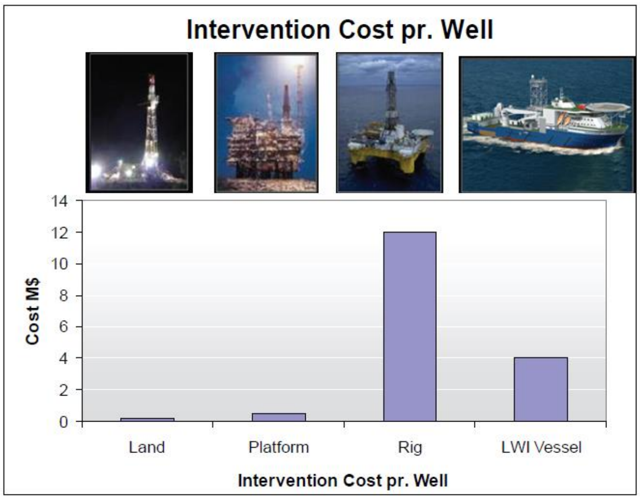


Figure 1-2 Intervention Cost with Different Techniques [3]

1.2. Objectives

This thesis will study the current P&A technique and also the future technology. However, this thesis specified the operation on subsea wells only. The main goals of this thesis are:

1. to perform a literature study about well plug and abandonment operation. It will cover the regulation, challenge, and the technique of P&A operation,
2. to evaluate the present available key technologies,
3. to discuss where the industry is moving regarding the P&A operation,

4. to see the feasibility of performing P&A operation using LWI vessel.

1.3. Report Structure

This master thesis consists of eight main chapters, which can be divided into:

- Chapter 1 describes brief introduction about the background and objectives of the master thesis.
- Chapter 2 gives a description about subsea wells. It covers the main components of subsea wells and also basic well elements. The methods to access subsea wells from a floating unit is also described.
- Chapter 3 discusses basic well barrier description.
- Chapter 4 describes the P&A, the general operation sequences, and the general challenges of the operation.
- Chapter 5 discusses three regulations of P&A operation in different offshore regions. NORSOK D-010 as the NCS regulation; Guidelines for the suspension and abandonment wells, from Oil & Gas UK, for the UKCS; and a regulation from US Bureau of Safety and Environmental Enforcement (BSEE) for the Gulf of Mexico.
- Chapter 6 introduces the current and future of P&A technologies to be used in LWI vessel. In this chapter, the challenges of performing P&A using LWI vessel is also described, followed by the proposed solutions of method and technologies.
- Chapter 7 concludes the master thesis with several recommendations.

2. Subsea Wells and Well Access Methods

2.1. Subsea Wells

This section explains briefly about subsea wellhead and Xmas tree. Wellhead and Xmas tree are key elements in a subsea production system and the interface point to the well for intervention and abandonment operations.

2.1.1. Subsea Wellhead

The main function of a subsea wellhead system (as run from a floating drilling vessel) is to serve as a structural and pressure-containing anchoring point on the seabed for the drilling and completion systems and for the casing strings in the well. It is the main connection point between the well and any equipment used during drilling, completion, and interventions. Figure 2-1 shows a typical configuration of subsea wellhead system.

A wellhead serves numerous functions, some of the functions are [4]:

- to provide a means of casing suspension
  (casing is the permanently installed pipe used to line the well hole for pressure containment, collapse prevention during the drilling phase),
- to provide a means of tubing suspension
  (tubing is removable pipe installed in the well through which well fluids pass),
- to provide a means of pressure sealing and isolation between casing at surface when many casing strings are used,
- to provide access to annuli between the different casing/tubing strings,
- to provide a means of attaching a Blow Out Preventer (BOP) during drilling,
- to provide a means of attaching an Xmas Tree for well control during production, injection, or other operations,
- to provide a reliable means of well access,
- to provide a means of attaching a well pump.

2.1.2. Subsea Xmas Tree

Subsea Xmas tree is a pressure containing unit with the main function to control and monitor the fluid flow from the subsea well. The Xmas tree system acts as the main interface between the well and subsea infrastructures. It is an assembly of valves which are used for controlling, testing, servicing, regulating, or choking the flow of fluids coming up from the well. Figure 2-2 shows an example of subsea Xmas tree.

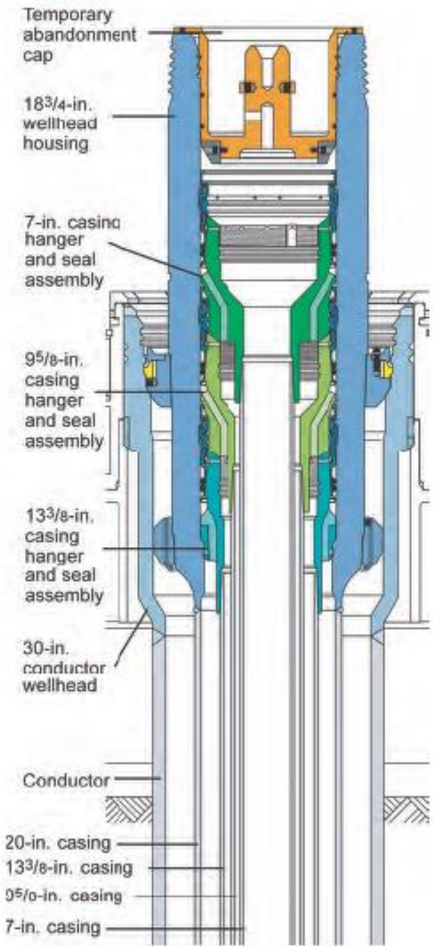


Figure 2-1 Illustration of A Typical Subsea Wellhead System with a 30 x 20 x 13-3/8 x 9-5/8 x 7 inch Casing Program [5]

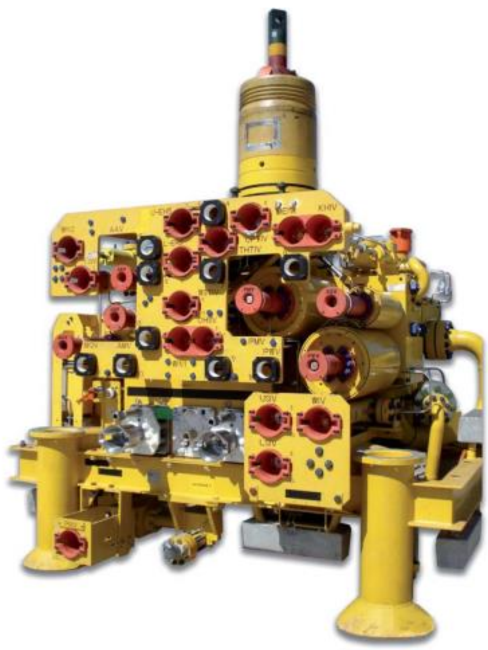


Figure 2-2 Horizontal Subsea Tree [6]

The subsea Xmas tree serves several functions, some of the functions are [7]:

- pressure vessel for well flow/pressure in completion mode,
- pressure vessel for well flow/pressure in production mode,
- accommodation of active barrier elements,
- accommodation of flow control elements,
- accommodation of injection systems,
- accommodation of monitoring systems,
- accommodation of the production control systems,
- accommodation of downhole control systems,
- accommodation of ROV interface panels.

There are two basic types of subsea Xmas tree according to the configuration of valves; vertical Xmas tree and horizontal Xmas tree. Figure 2-3 shows the differences between those two configurations.

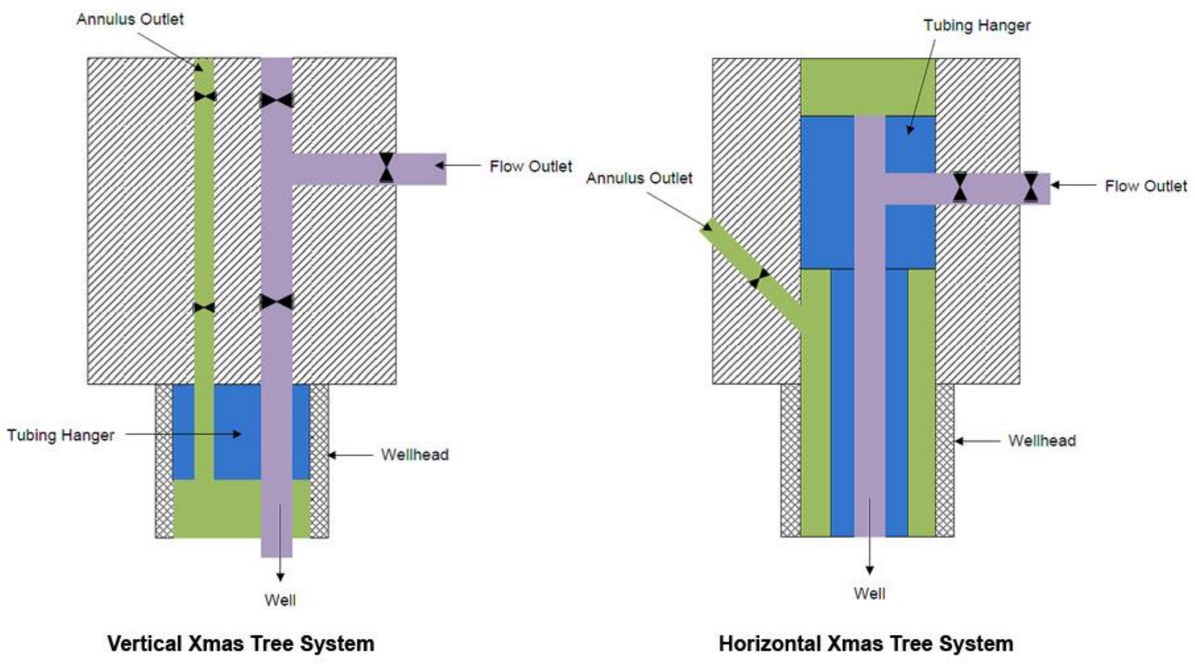


Figure 2-3 Vertical vs Horizontal Xmas Tree [8]

2.1.2.1. Vertical Xmas Tree

For vertical Xmas trees, the tubing hanger and tree are dual bore. Usually, it consists of 5” production bore and 2” annulus bore. There is a crossover valve for communication access between the production and the annulus side of the tree. In this system, the master valve is located directly above the tubing hanger in the vertical run of the flow path. The tubing hanger and the tubing are run prior to installing the tree and rest in the wellhead. Therefore, the tree needs to be retrieved to get access to tubing hanger for any intervention or workover. This type of tree is usually used for a well that needs a low frequency of tubing retrieval.

For P&A operations, the vertical Xmas tree needs to be retrieved before the tubing hanger and tubing are retrieved to the surface.

2.1.2.2. Horizontal Xmas Tree

Opposed to the vertical one, the horizontal Xmas tree and the tubing hanger are monobore. The tree has a 5" or 7" of production master valve and 2" annulus master valve offset from the vertical bore. The master valve is in the horizontal run adjacent to the wing valve, i.e. there are no tree valves in the vertical portion of the flow path. The tubing hanger is installed inside the tree. Consequently, the tree does not need to be recovered in order to retrieve the tubing. Therefore, this type of tree has advantages for a well that requires frequent workovers requiring tubing retrieval.

For P&A purposes, the tubing hanger and tubing need to be pulled out before the tree can be retrieved.

2.1.3. Casings and Tubing

Casing and tubing strings are the main components of a well construction. All wells drilled for the purpose of oil/gas production (or injecting materials into underground formations) must be cased with material with sufficient strength and functionality. The following subsection will describe the general overview and main functions of casings and tubing.

2.1.3.1. Casing

Casing is the major structural component of a well. There are several functions of casing [5]:

- to maintain borehole stability;
- prevent contamination of water sands;
- isolate water from producing formations;
- control well pressures during drilling, production, and workover operations.

Furthermore, casing provides locations for the installation of blowout preventers, wellhead equipment, production packers, and production tubing. Figure 2-4 shows the typical of casing program. Although there are several sizes of casing strings, the typical sizes of casing strings that are commonly used:

- Conductor casing : 30" diameter
- Surface casing : 20" diameter

- Intermediate casing : 13-3/8” diameter
- Production casing : 9-5/8” diameter
- Production liner : 7” diameter

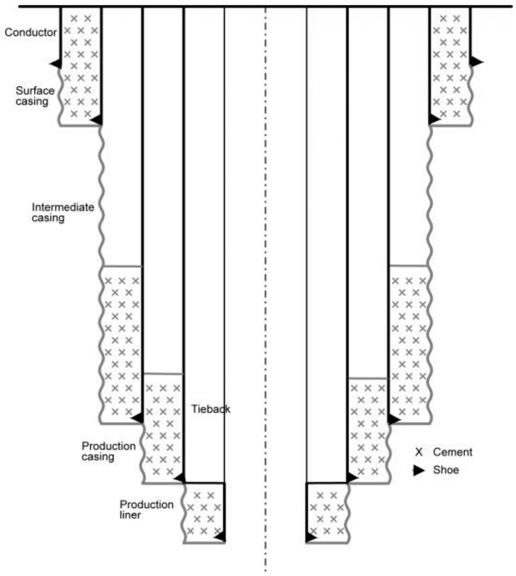


Figure 2-4 Typical Casing Program [5]

Conductor Casing

Conductor casing is typically the first (and largest diameter) pipe installed during construction. The functional requirements of conductor casing are [9]:

- to isolate unconsolidated layers below the seabed,
- to support template and marine riser on floating rigs, and mudline suspension/riser system on jack-up rigs. Extend the well to deck on fixed platforms,
- to support surface casing and wellhead.

Surface Casing

After the conductor casing is installed and cemented, the hole is drilled deeper and the next casing to be installed is surface casing. The functional requirements of surface casing are [9]:

- to isolate weak formations down to a depth where the formation integrity is sufficient to ensure proper control of abnormally pressured formations in the hole below,
- to support the wellhead and the BOP,
- to isolate the formations down to any potential shallow gas zone or isolate such zones in order to establish integrity for further drilling.

Intermediate casing

After the surface casing has been set and properly cemented, drilling of the intermediate hole and installation of intermediate casing starts. The functional requirements of intermediate casing are [9]:

- to isolate all formations up to the surface casing shoe so that the next hole section can be drilled safely and efficiently through the pay zone,
- to give sufficient well integrity for drilling the pay zone or any abnormally pressurized zones as requested by the drilling program,
- to fulfill production casing design requirements if only a production liner is planned below.

Production casing

Production casing is the final length of steel pipe used in wellbore construction. The functional requirements of production casing are [9]:

- to isolate the productive zones,
- to ensure proper cementing of the annulus across the productive zones, so that fluid cannot migrate along the wellbore,
- to withstand mechanical and chemical wear from the formation and completion fluids over the planned production lifetime of the well,
- to maintain well integrity during all planned production and workover periods.

Liner

Liner is a casing string that does not extend back to the wellhead but is hung from another casing string. There are several reasons of why liners are used instead of full casing strings, such as [5]:

- reduce cost,
- improve hydraulic performance when drilling deeper,
- allow the use of larger tubing above the liner top,
- not represent a tension limitation for a rig.

Liners can be either an intermediate or a production string. Liners are typically cemented over their entire length [5].

2.1.3.2. Tubing

The tubing (production tubing) is a pipe used inside a wellbore as a conduit through which oil and gas produced from the reservoir to the surface facilities for processing. Tubing gives protection to the casing from wear, tear, corrosion, and also depositions of sand, paraffin, etc. Production tubing is run into the drilled well after the casing is run and cemented, so it is one of the last things that installed before the production starts. Consequently, production tubing may be the first thing to be removed in the P&A activity.

2.1.4. Well Cementing

Cementing is one of the most important operation inside of the well during drilling, completion, and abandonment. The cement main functions are to hold the casing in place and to prevent fluid migration. Well cementing operation consists of two categories; primary cementing and remedial cementing [5].

2.1.4.1. Primary Cementing

Primary cementing is the cementing that takes place immediately after the casing has been run into the hole during the drilling operation to fill the annulus between the casing and the formation. The objective of primary cementing is to provide zonal isolation. Cementing is the process of mixing a slurry of cement, cement additives, and water and pumping it down through the casing to critical points in the annulus around the casing or in the open hole below the casing string [5].

2.1.4.2. Remedial Cementing

Remedial cementing is usually done to correct problems associated with the primary cement job. The need for remedial cementing to restore a well's operation indicates that primary operational planning and execution were ineffective, resulting in costly repair operations. Remedial cementing operations consist of two broad categories, which are *squeeze cementing* and *plug cementing* [5].

The principal purpose of squeeze cementing, self-explained by its name, uses pressure to force cement slurry into specific place in a well to provide a seal. It is a correction process that is usually needed to correct problem inside of the wellbore. While the other method, plug cementing, is usually used when a well is to be abandoned or when a zone needs to be isolated.

2.2. Subsea Well Access Methods

During the life of a field, interventions and workovers are necessary to improve and optimize field recovery. And at the end of the life of a field, P&A will be the operation that is needed. For subsea wells, certain techniques are needed to access inside of the wellbore to perform all those operations. Within this section, the units, tools, and methods that are usually used to perform operation inside of the wellbore in a subsea well are described. Nonetheless, in this thesis, the well operation that is discussed is P&A. The process of P&A itself is described in chapter 4. For the general overview, Table 2-1 shows the typical subsea well access techniques.

Table 2-1 Subsea Well Access Overview [7]

Subsea Well Access Method (Intervention/Workover/Abandonment)			
Units	Cat A	Cat B	Cat C
Tools	Wireline	Wireline Coiled Tubing	Full Drilling Completion Workover
Methods	Riserless	Workover Riser (» 7")	Marine Riser (21")

2.2.1. Unit Used to Access Subsea Well

Subsea well operations can be performed from different types of units depending on the method and the equipment to be used. There is no standardized categorization for the vessel/rig that used for well intervention activity. Different company has different categorization. However, Figure 2-5 shows an example of the general categorization of units for well intervention that can also be used for P&A activity.

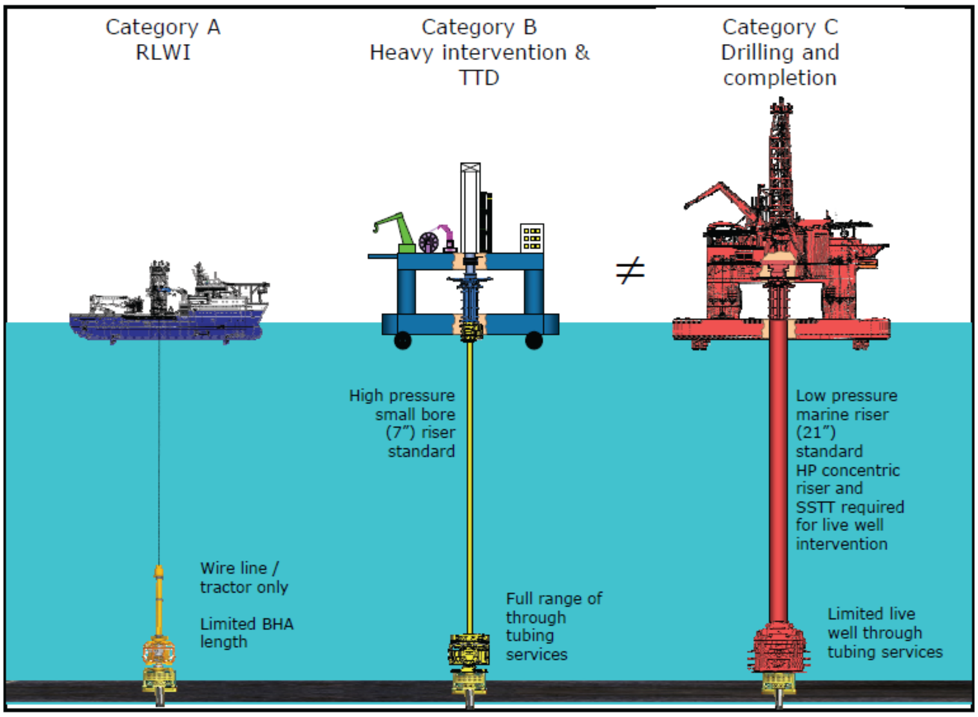


Figure 2-5 Illustration Showing the Differences Between Category A, B, and C [3]

2.2.1.1. Category A

The category A unit is commonly called LWI vessel. This vessel serves operations without the requirement of deploying a 21” marine drilling riser or 7” small bore riser. Thus, the operations performed is riserless. Because of this, this type of vessel is also frequently called a Riserless Light Well Intervention (RLWI) Vessel. Typically, wireline is used for intervention operations using this vessel. It connects to subsea well with dedicated RLWI stack that is described in chapter 2.2.4.

Island Offshore is one of the companies that provides category A vessel. Some examples of their vessels are shown in Figure 2-6. Even though there is no standard with regard to the size, typically, category A vessels vary between 100 – 140 m in overall length.

Island Frontier
(Year of Delivery 2004)

Deadweight	4706 tons
Cargo Deck Area (main)	945 m²
Max Speed	12 knots
Generator Power	10440 Kw
Length Overall	106.2 m
Breadth Moulded	21 m
Depth to Main Deck	8.2 m
Design Draught	6.2 m
Dynamic Positioning	DP-3

Island Wellserver
(Year of Delivery 2008)

Deadweight	9200 tons
Cargo Deck Area (main)	1050 m²
Max Speed	14 knots
Generator Power	13440 Kw
Length Overall	116 m
Breadth Molded	25 m
Depth to Main Deck	11.2 m
Design Draught	7.7 m
Draught Max	8.7 m
Dynamic Positioning	DP-3

Island Constructor
(Year of Delivery 2008)

Deadweight	9100 tons
Cargo Deck Area (main)	1380 m²
Cargo Deck Area (Mezzn)	320 m²
Max Speed	15 knots
Generator Power	13800 Kw
Length Overall	120.2 m
Breadth Molded	25 m
Depth to Main Deck	10 m
Design Draught	7 m
Draught Max	8 m
Dynamic Positioning	DP-3

Figure 2-6 Island Offshore Category A Vessels [10]

Although the category A is usually called RLWI vessel, it is In this thesis, the term LWI vessel is generally used for this type of vessel.

2.2.1.2. Category B

The category B service includes extensive well maintenance capabilities using coiled tubing operations through a riser for treatments such as removal of severe blockages and restrictions, fishing obstructions, control of unwanted water and gas influx, re-perforation, stimulation, and restoring production in watered-out wellbores [11]. Figure 2-7 shows an example of category B rig.

Figure 2-7 Helix Q4000 [12]

The main concept of this category is to use a high-pressure small bore riser (~7") for performing heavy interventions such as coiled tubing. For P&A operation, with the use of coiled tubing, this type of rig can displace cement that makes it possible to set cement plugs in the well and squeeze cement in the annulus.

2.2.1.3. Category C

This category covers the conventional rigs with low-pressure risers. This unit is capable of performing all of the operations required for well intervention and P&A operation. Even though this category of rig can carry out all of the heavy well interventions, they are highly expensive and have limited availability, making them a less attractive solution for P&A operation. Figure 2-8 shows an example of category C rig.

Figure 2-8 Seadrill West Alpha Rig [13]

In this thesis, the LWI vessel is defined to be within size range 100 – 140 m, without considering the categories as defined above. Generally, this means monohull vessels.

2.2.2. Type of Tools to Works Inside Subsea Well

There are several types of methods for intervention operations based on the tools and the equipment to be used such as wireline, coiled tubing, and hydraulic workover unit. Within this section, the most common tools to be used in abandonment activity are described.

2.2.2.1. Wireline

Wireline usually refers to a cabling technology that is used by operators of oil and gas wells to lower equipment or measurement devices into the well for the purposes of well intervention, reservoir evaluation, and pipe recovery [14]. Based on the purposed application of intervention, there are different types of cables or wires; slickline, e-line and braided line. Figure 2-9 shows the typical wireline configuration in a subsea well.

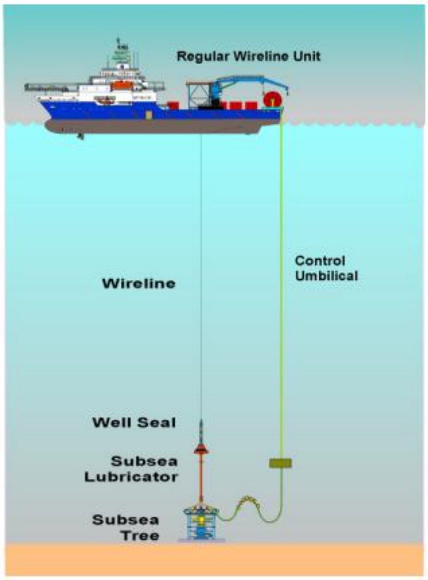


Figure 2-9 Standard Configuration for Wireline Operations [15]

Although wireline is routinely used as a cost-effective well operation, there are several limitations in performing an operation using wireline, such as there is no jacking power and also no possibility to circulate the fluid through the wire. However, bullheading of fluid and plugging material in P&A activity can be done by connecting pumps via temporary flow lines to the Xmas tree of the well. Figure 2-10 lists typical wireline operations.

Typical Wireline Applications

- Data gathering (PLT/RST and Caliper)
- Perforation/ re – perforation of well
- Well killing operation
- Pumping operations/Scale treatments
- Selective tracer injection or sampling
- Change out of gas lift valves
- Zone isolation (plug/ straddle)
- Tubing to annulus leakage (straddle)
- Inspection/repair/ installation of insert DHSV
- Milling of short scale bridges
- Camera / inspection
- Sleeve operations – on smart wells
- Change out of subsea trees
- Temporary P&A operations of subsea wells

Figure 2-10 Typical Wireline Operations [16]

2.2.2.2. Coiled Tubing

Coiled Tubing is an electric-welded tube manufactured with one longitudinal seam formed by high-frequency induction welding without the addition of filler metal [5]. Tubing diameter normally ranges from 0.75” to 4”. Figure 2-11 shows typical coiled tubing unit.

The main advantage of coiled tubing is the ability to circulate the fluid during the intervention operation. Therefore, it may be possible to plug the well with cement using coiled tubing. Another advantage is the ability to apply force during running the tool to overcome pressure and friction inside of the well.

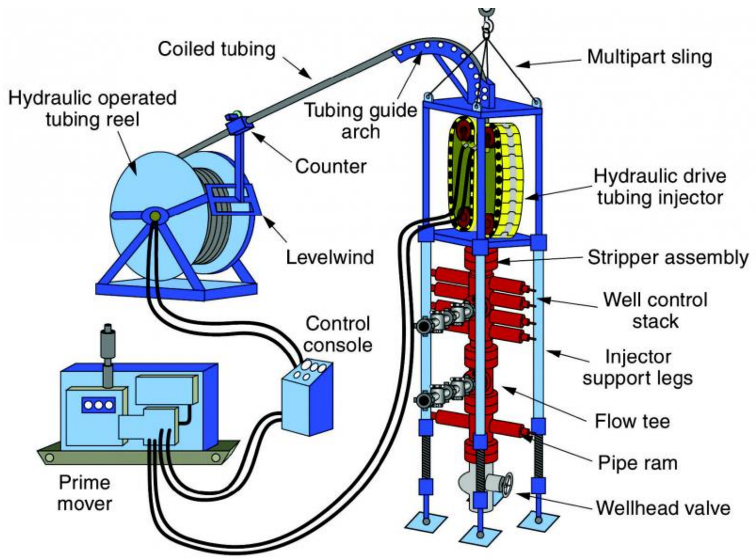


Figure 2-11 Mechanical Elements of a Hydraulic Coiled Tubing Unit [5]

The coiled tubing unit is comprised of the complete set of equipment necessary to perform standard continuous-length tubing operations in the field. The unit consists of four basic elements [17]:

- reel - for storage and transport of the coiled tubing,
- injector head - to provide the surface drive force to run and retrieve the coiled tubing,
- control cabin - from which the equipment operator monitors and controls the coiled tubing,
- power pack - to generate hydraulic and pneumatic power required to operate the coiled tubing unit.

Some of the most common coiled tubing applications for workover operations are listed in Figure 2-12.

Mechanical Applications

- Setting a plug or packer
- Fishing
- Perforating
- Logging
- Scale removal (mechanical)
- Cutting tubulars (mechanical)
- Sliding sleeve operation
- Running a completion
- Straddles for zonal isolation
- Drilling

Pumping Applications

- Removing sand or fill from a wellbore
- Fracturing/acidizing a formation
- Unloading a well with nitrogen
- Gravel packing
- Cutting tubulars with fluid
- Pumping slurry plugs
- Zone isolation (to control flow profiles)
- Removal of scale, wax, hydrocarbon, or hydrate plugs

Figure 2-12 Typical Coiled Tubing Operations [17]

2.2.3. Riser Based Well Intervention

One of the methods to access a subsea well is via rigid riser package that has a direct connection to the surface. Large marine riser (usually 21" of diameter) is conventionally used with BOP installed on top of the subsea tree or on the wellhead. Then workover riser is run inside the marine riser to perform the operation. This workover riser gives direct access to the well at full pressure rating and diameter of the downhole completion. Figure 2-13 and Table 2-2 give a general overview of the configuration and basic components of riser based well intervention system.

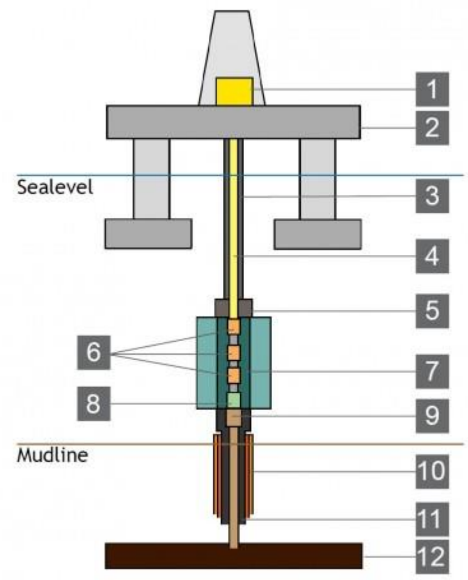


Figure 2-13 Typical Configuration of Riser Based Well Intervention [18]

Table 2-2 The Most Common Components for Riser Based Well Intervention [18]

No.	Equipment	Function
1	**Surface Flow Tree**	To provide facilities to flow, kill and control the well during workover and completion operations. In addition to this, it can be fitted with adapters to facilitate wireline operations during operations.
2	**Rig**	To facilitate deployment of equipment subsea.
3	**Marine Riser**	To establish a physical connection between the rig and the BOP. (Rig Equipment)
4	**Workover Riser**	To establish a physical connection between the rig and the Landing String deployed inside the marine riser. The workover riser also gives possibilities to circulate fluid, test production, well control and deployment of wireline tools
5	**Lower Marine Riser Package (LMRP)**	Enables quick disconnect of the marine riser from the Blow Out Preventer in emergency scenarios. (Rig Equipment)
6	**Landing String**	Facilitates well control during operations
7	**BOP**	Enables well control in emergency scenarios (Rig Equipment)

No.	Equipment	Function
8	**Tubing Hanger Running Tool**	Tool for installation/retrieval of Tubing Hanger
9	**Tubing Hanger and Xmas Tree**	Installed on the well and subject to workover/completion operations using the Workover System
10	**Wellhead**	Interface between the Xmas Tree/Tubing Hanger and the well
11	**Completion/Tubing**	Connection between the wellhead and the well
12	**Well**	Reservoir to be exploited

The conventional method as described above has major disadvantages because of the installation of 21" marine riser. The installation of that 'big' riser takes a long time, especially in deep water sea. This makes the utilization of this method is less cost-effective. However, utilization of modern technology such from category B (or A with modifications) unit can give a better solution with high-pressure workover riser run without the marine riser and seabed BOP. Although it is important to note that this unit cannot perform a full drilling capability as provided by category C rig.

The system has lower riser package (LRP) as a well control package and also emergency disconnect package (EDP). The workover riser is attached to the LRP and surface flow tree as illustrated in Figure 2-14 and explained in Table 2-3.

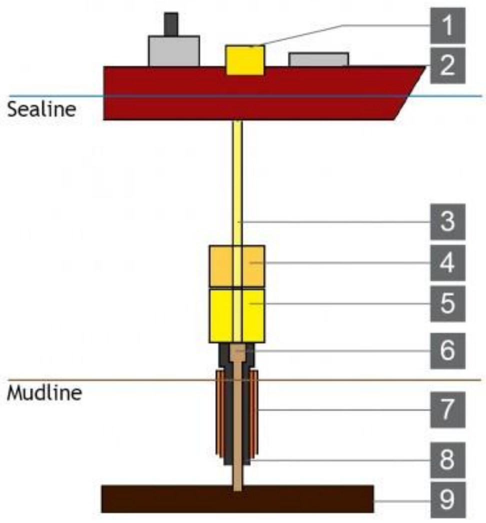


Figure 2-14 Workover Riser Well Intervention System [18]

Table 2-3 Components of Intervention with Workover Riser System [18]

No.	Equipment	Function
1	**Surface Flow Tree**	To provide facilities to flow, kill and control the well during workover and completion operations.
2	**Rig/Vessel**	To facilitate deployment of equipment subsea.
3	**Workover Riser**	To establish a physical connection between the rig and the Landing String deployed inside the marine riser. The workover riser also gives possibilities to circulate fluid, test production, well control and deployment of wireline tools
4	**EDP**	Enables quick disconnect of the marine riser from the BOP in emergency scenarios. (Rig Equipment)
5	**LRP**	Enables well control in emergency scenarios (Rig Equipment)
6	**Tubing Hanger/Xmas Tree**	Installed on the well and subject to workover/completion operations using the Workover System
7	**Wellhead**	Interface between the Xmas Tree/Tubing Hanger and the well
8	**Completion/Tubing**	Connection between the wellhead and the well
9	**Well**	Reservoir to be exploited

Without the installation of the 'big' marine riser, this type of design is much faster in installation than the conventional one. Moreover, this system is also capable of handling wireline and coiled tubing activity.

2.2.4. Riserless Well Intervention

Riserless well intervention refers to any intervention performed without riser during interventions on subsea wells. As mentioned in section 2.2.1.1, the unit used for this type of intervention is usually Category A and usually called RLWI vessel. RLWI operations have been operated in the North Sea for more than 25 years. In the last 10 years alone, the 3 RLWI vessels operated by Island Offshore have accessed more than 338 wells [19]. In this method, wireline is mainly used for lowering the tools needed for subsea wells intervention.

The system is compatible with both horizontal Xmas tree and conventional Xmas tree. All wireline activities are applicable to this method. The common configuration for this method is illustrated in Figure 2-15 and described in Table 2-4.

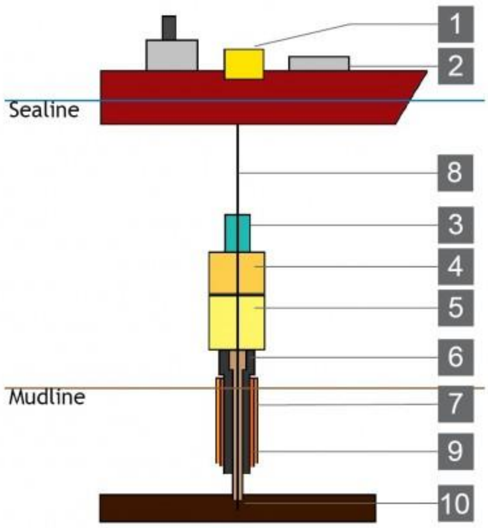


Figure 2-15 Riserless Well Intervention Configuration [18]

Table 2-4 Components of Riserless Well Intervention System [18]

No.	Equipment	Function
1	**Surface Flow Tree**	To provide facilities to flow, kill and control the well during workover and completion operations. It can be fitted with adapters to facilitate wireline operations during operations.
2	**Vessel**	To facilitate deployment of equipment subsea.
3	**Lubricator Package**	To enable deployment of wireline tools and logging equipment into the well through the EDP/ Well Control Package (WCP)
4	**EDP**	Enables quick disconnect of the marine riser from the BOP in emergency scenarios. (Rig Equipment)
5	**LRP**	Enables well control in emergency scenarios (Rig Equipment)
6	**Tubing Hanger/Xmas Tree**	Installed on the well and subject to workover/completion operations using the Workover System
7	**Wellhead**	Interface between the Xmas Tree/Tubing Hanger and the well
8	**Control Umbilical**	Enable communication/control of the subsea equipment from vessel/rig

No.	Equipment	Function
9	**Completion/Tubing**	Connection between the wellhead and the well
10	**Well**	Reservoir to be exploited

Besides the general configuration of riserless well intervention system as described before, there is also an RLWI stack of equipment that is commonly used in the industry. The so-called 'RLWI stack' has the main role as well control equipment during the intervention. Figure 2-16 shows the stack configuration provided by FMC Technologies. Technical description of the modules shown in the figure are explained below [20].

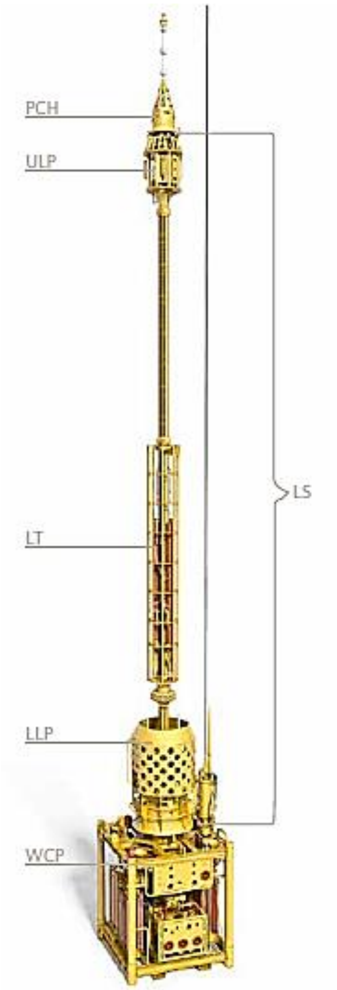


Figure 2-16 FMC RLWI Stack [20]

Pressure Control Head

The PCH contains the connector for attachment to the top of the Lubricator Section (LS), and the sealing section with the flowtubes, sealing off the intervention wire from the wellbore pressure below and the open water above.

Upper Lubricator Package (ULP)

The ULP is mounted on top of the LT. It contains the wireline cutting ball valve, the circulation outlet, and the connector hub towards PCH.

Lubricator Tubular (LT)

The LT is mounted on top of the LLP and carries the grease reservoirs and the high-pressure grease injection pumps. When well intervention tools are placed in the lubricator and the lubricator pressurized to wellbore pressure, tools may be conveyed into the wellbore under live well pressure.

Lower Lubricator Package (LLP)

The LLP provides the safety Joint in the RLWI Stack and is designed to bend if the stack is exposed to excessive forces, protecting permanent equipment from excessive loads. The lower part contains the connector to be attached to the WPC. The LLP also houses the Subsea Control Modules (SCM) and the subsea hydraulic pressure unit (HPU) and hydraulic accumulators, controlling the RLWI Stack.

Lubricator Section (LS)

The LS consists of the ULP, the LT, and the LLP. The PCH is connected to the top of the Lubricator subsea., sealing off the intervention wire from the wellbore pressure below and the open water above.

Well Control Package (WCP)

The WCP is installed on top of the Xmas tree. It contains the upper valve block, the shear/seal ram, and the lower valve block. The WCP serves the purpose of the conventional LRP and provides the main safety barrier during the well intervention operation. In case of an uncontrolled well situation, the shear/seal ram will cut the wireline, coiled tubing or wireline toolstring inside the wellbore. By use of the cross-over valves, the WCP enables flushing of hydrocarbons back into the well. During an intervention operation, the WCP interface provides hydraulic pressure and supply, as well as communication to Xmas tree functions.

2.2.4.1. RLWI Limitations

As mentioned in a Master Thesis made by Valdal [16], the RLWI method vessels have some limitations/disadvantaged compared to the riser based intervention with conventional rig:

1. The difficulty in reaching the target in the wellbores if the well is very deep and with a high angle. However, this issue can be minimized after the utilization of wireline tractor tools. This tools can increase the max pulling forces of the wireline.
2. The inability for fluid pumping and circulation to perform sufficient well clean up. However, bullheading is possible and the well can also produce to the platform while RLWI vessel is connected with the RLWI stack on top of the Xmas tree.
3. The difficulty in establishing cement barrier plug, due to no drill pipe or coiled tubing. However, the experience of performing open water coiled tubing or the installation of riser may overcome this issue. This is discussed in section 6.3.1.
4. The weather limitation for an RLWI vessel.

3. Well Barrier

Safety is critical in oil & gas industry. Every company in this industry has a responsibility to carry out every action safely and in an environmentally friendly manner. On the NCS, the technical and operational safety is controlled by The Petroleum Safety Authority (PSA) Norway. The NORSOK standards are developed to make sure all petroleum-related activities on the NCS are carried out in a safe manner. Other regions have their own authority and regulation to control all activities.

Production of oil and gas from a pressurized reservoir involves risk of unintended flow of oil and gas to the environment. To prevent this, subsea installations are designed with several devices (barriers) to avoid that possible incidents or malfunction of equipment causes leakage and flow of produced/injected fluids to the environment. Barrier is technical, operational, and organizational elements which are intended individually or collectively to reduce the possibility of a specific error, hazard, or accident to occur [21].

3.1. Well Barrier Definition

According to NORSOK D-010, well barrier is defined as envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment [22]. Well barrier is needed to be established in all well activities, such as drilling, intervention, and P&A. Although definitions can vary from regulation to regulation, basically, there is a ‘rule of thumb’ that at least two independent barriers should be established at all times; a primary and a secondary barrier.

The Primary well barrier is the first well barrier that prevents flow from a potential source of inflow. The Secondary well barrier is the second object that prevents flow from a source [22]. The secondary barrier is a backup in case the primary barrier fails. Generally, it has to be independent of the primary barrier, that is, any event that could destroy the primary barrier should not affect the secondary barrier. They should as far as possible be independent of each other with no common Well Barrier Element (WBE). (A WBE is defined as a physical element which in itself does not prevent flow but in combination with other WBE’s forms a well barrier [22]). However, in some cases, there is also ‘common well barrier element’, which is a barrier element that is shared between the primary and secondary well barrier. Figure 3-1 shows an example of well barriers in a production well (horizontal Xmas tree).

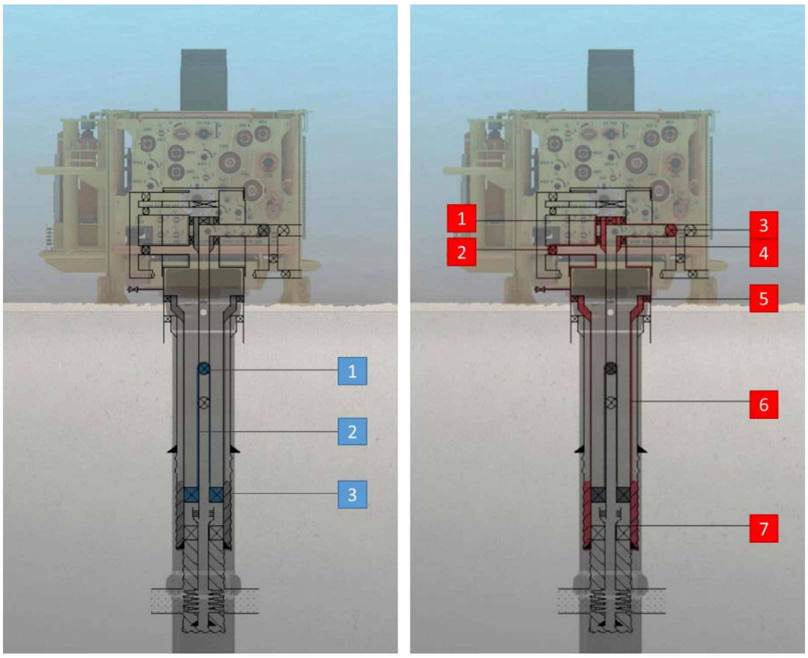


Figure 3-1 Well Barriers in the Horizontal Xmas Tree System [23]

Table 3-1 Well Barrier System in Horizontal Xmas Tree [23]

Primary Well Barrier		
No.	**Well Barrier Element**	**Function as Well Barrier**
1	Surface Controlled Subsurface Safety Valve (SCSSV)	Preventing flow of hydrocarbons or fluid up the tubing.
2	Completion String	Providing a conduit for formation fluid from the reservoir to surface or vice versa.
3	Production Packer	- Preventing communication from the formation into the A annulus above the production packer. - Preventing flow from the inside of the body element located above the packer element into the A annulus as part of the completion string.
Secondary Well Barrier		
No.	**Well Barrier Element**	**Function as Well Barrier**
1	Tubing Hanger Plug	Providing a pressure well barrier in the bore through the Tubing Hanger
2 & 3	Production Xmas Tree (Annulus Master Valve (2) & Production Master Valve (3))	Stopping the flow by closing the flow valve
4	Tubing Hanger	- Preventing flow from the bore and to the annulus - Providing a seal in annulus space between itself and the wellhead

5	Wellhead	Preventing flow from the bore and annuli to the formation or the environment.
6	Casing	Providing a physical hindrance to uncontrolled flow of hydrocarbon fluid
7	Casing Cement	Providing a seal along hole in the casing annulus or between casing strings

Although normally the 'rule of thumb' is to have at least two independent well barriers, there are some cases where NORSOK only demands one well barrier, such listed in Table 3-2. However, for wells that need to be plugged and abandoned, a combination of several well barriers has to be considered. This is discussed in Chapter 5.

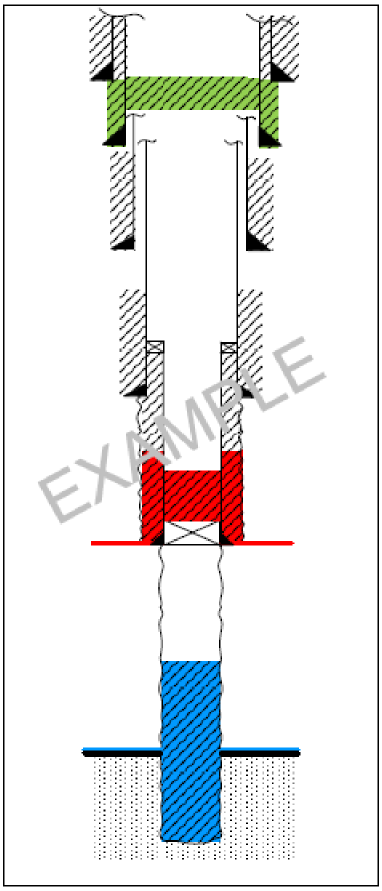
Table 3-2 Number of Barriers [22]

Minimum Number of Well Barriers	Source of Inflow
One well barrier	a) Undesirable cross flow between formation zones b) Normally pressured formation with no hydrocarbon and no potential to flow to surface c) Abnormally pressured hydrocarbon formation with no potential to flow to surface
Two well barriers	d) Hydrocarbon bearing formations e) Abnormally pressured formation with potential to flow to surface

3.2. Well Barrier Schematics

NORSOK D-010 recommends drawing well barrier schematic (WBS) during all phases in a well. WBS is an illustration that should be developed to show the presence of primary and secondary well barrier for all operations in a well. An example of a WBS is shown in Figure 3-2. The primary well barrier is presented in blue color. While secondary barrier is marked in red. For this example, there is another barrier, which is the open hole to surface barrier, because for permanent abandoned well, it is usually not enough with two well barriers. This barrier is shown in green color.

The column Well Barrier Elements describes the different WBEs included in the well barrier envelope. The EAC column (Element Acceptance Criteria), is discussed in the next subsection. The last column describes the requirements for testing the well barrier elements.



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Cement plug	24	
Secondary well barrier		
Formation in-situ	51	
Casing cement	22	
Casing	2	
Cement plug	24	
Open hole to surface well barrier		
Casing cement	22	
Casing	2	
Cement plug	24	

Figure 3-2 WBS of a Permanent Abandoned Well [22]

3.3. Well Barrier Elements Acceptance Criteria

Every WBEs has to meet several criteria in order to be accepted as a part of a well barrier. There may be several terms for those criteria, but in NORSOK D-010 it is known as Well Barrier Elements Acceptance Criteria (WBEAC). According to NORSOK D-010, a well barrier can be accepted if it is designed such that:

- It can withstand the maximum differential pressure and temperature it may become exposed to.
- It can be pressure tested, function tested or verified by other methods.
- No single failure of a well barrier or WBE can lead to an uncontrolled flow of wellbore fluids or gases to the external environment.
- It is possible to re-establish a lost well barrier or establish another alternative well barrier.
- It can operate competently and withstand the environment for which it may be exposed to over time.
- It is possible to determine the physical position/location and integrity status at all times.
- It should be independent of each other and avoid having common WBEs.

Each WBEs has their own qualification method to be accepted as per the regulation. Beside design of the barrier itself, some tests are usually needed after installation of the barrier. For example, a leak test of a barrier shall be done with a spesific acceptable leak rate. Moreover, a function test also may be needed to demonstrate that the barrier has good sealing properties. Further discussion regarding WBEAC is described in Chapter 5.

4. Plug and Abandonment

4.1. P&A Definition

P&A is the process to install permanent well barriers to seal off a well or a section of a well to prevent cross-flow or migration of hydrocarbons to surface with an eternal perspective [24]. As mentioned in the Introduction, all wells need to be plugged and abandoned at some time, after have served their purposes. The objective of well abandonment is to make sure that there will be no negative impact on the environment after the well is left behind. Figure 4-1 is a simple illustration of what a wellbore may look like with the P&A operation with some permanent well barriers in place.

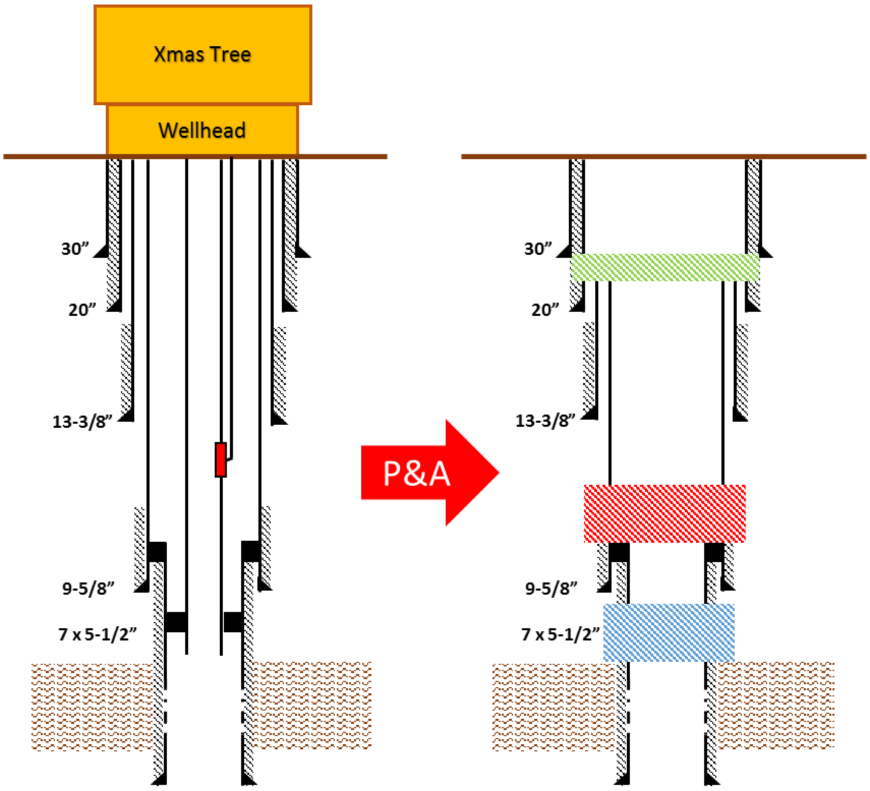


Figure 4-1 Permanent Abandonment Illustration

NORSOK D-010 has its own terms to define plug and abandonment [22]:

- **Plugging –** operation of securing a well by installing required well barriers.
- **Temporary abandonment (with monitoring) –** well status, where the well is abandoned and the primary and secondary well barriers are continuously monitored and routinely tested.

- **Temporary abandonment (without monitoring) –** well status, where the well is abandoned and the primary and secondary well barriers are not continuously monitored and not routinely tested.
- **Permanent abandonment** – well status, where the well is abandoned and will not be used or re-entered again.

4.2. P&A General Operation Sequences

There are a lot of factors that influence the procedure of a P&A operation. It is not a straightforward task to describe it. There is no written literature that can give 'generic recipe' of how to execute it. This is because there is a large variation of petroleum wells today. The type of well, well condition, and the cement status are examples of the variations.

According to NORSOK D-010, the following information should be a design basis of the P&A program [22]:

1. Well configuration (original and present) including depths and specification of formations which are source of inflow, casing strings, casing cement, wellbores, sidetracks.
2. Stratigraphic sequence of each wellbore showing reservoir(s) and information about their current and future production potential, with reservoir fluids and pressures (initial, current and in an eternal perspective).
3. Logs, data and information from primary cementing operations.
4. Formations with suitable WBE properties.
5. Specific well conditions such as scale build up, casing wear, collapsed casing, fill, H_2S, CO_2, hydrates, benzene or similar issues.

Although abandonment procedure differs from one well to another, P&A operation can be generally summarized as follows, which are discussed in the following subsections:

- killing the well;
- pull tubing and lower completion;
- plug the reservoir (primary and secondary barriers);
- establish open hole to surface barrier;
- remove upper part of conductor, wellhead, and casing strings.

4.2.1. Killing the Well

The first step of P&A operation is to kill the well. This is a term used for stopping the flow of the hydrocarbon inside the well. Well killing is accomplished by putting a heavy fluid inside the wellbore to make the hydrostatic pressure higher than the formation pressure. This activity will eliminate the need for pressure control equipment at the surface.

The most common way to kill a well is by bullheading. Bullheading is a process of forcing fluids in the pipe into the formation at a pressure higher than the pore pressure and sometimes higher than the fracturing breakdown pressure [25]. In another way, it is a process in which fluid is forced into the well against its pressure by pumping. The killing fluid will press the fluid inside the well back into the formation.

According to [26], the 'well killing' stage usually includes punching the tubing and circulating heavy fluid down the tubing and up the annulus. If a well is equipped with a vertical tree, the well is secured by temporary barriers before pulling the vertical tree. Following securing the well by temporary barriers, the vertical tree is nippled down and BOP is nippled up. If a well is equipped with a horizontal tree, it is not required to secure the well with temporary barriers. The BOP can be installed on top of the horizontal tree or the horizontal tree might be used instead of the BOP. A diagnostic logging run can be performed at this stage to assess the quality of downhole equipment and well condition.

4.2.2. Pull Tubing and Lower Completion

Production tubing and lower completion can be left inside of the hole during P&A operation. However, the current normal practice of P&A is to pull the tubing. This is caused by several reasons. One of the reasons is to remove the control lines outside of the tubing because it may create a vertical leak path in the barrier. Figure 4-2 illustrates inside of the well. The parts below the production packer are usually referred as lower completion.

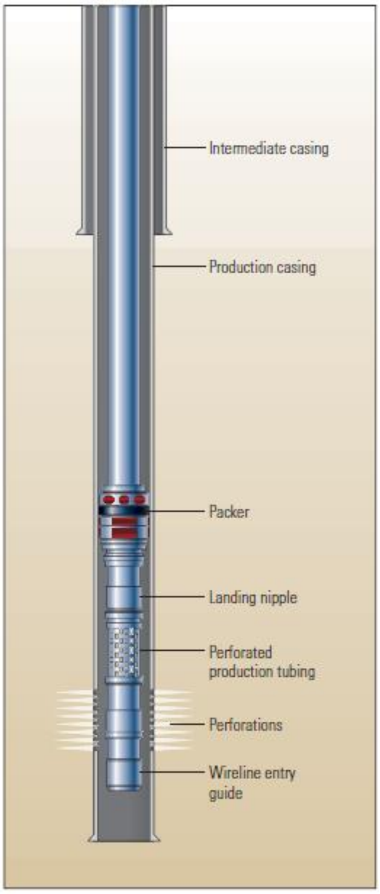


Figure 4-2 Production Tubing and Lower Completion [27]

The general procedure for vertical Xmas tree is to cut the tubing above the production packer (if not retrievable), remove the Xmas tree, install the BOP and then pull the tubing [28].

For the option to leave the tubing inside, proper verification method to check the quality of cementing barrier inside and around the tubulars is needed. However, currently, there is no accurate technology to log multiple casing strings. This is another reason why the common practice is to pull all production tubulars.

4.2.3. Plug The Reservoir (Primary and Secondary Barriers)

Before plugging the reservoir, usually logging is done to determine the quality of the cement inside the annulus. If the logs show good results, then cement can be established inside the casing. The barrier must include all annulus, extending to the full cross section of the well and seal both vertically and horizontally as illustrated in Figure 4-3. Nonetheless, as mentioned before, there is no logging technology which can log multiple casings. If the logs show poor quality of cement or lack of casing cement outside of the casing, then the traditional way is to perform an operation called section milling. This is one of the challenges of P&A operation, making the P&A operation becomes more complex. Section milling will be described in section 4.4.3.1. There is also the newer technique called perforate, wash, and cement (PWC) to complete this phase of operation. The technique will be discussed in section 6.3.3.

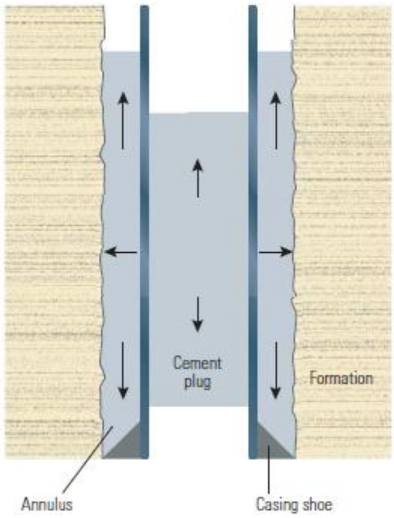


Figure 4-3 Basic Plug [27]

4.2.4. Establish Surface Barrier

The surface barrier is a "fail safe" barrier, where a potential source of inflow is exposed after e.g. a casing is cut [16]. If the casing cement quality is good, it is sufficient to establish the barrier inside the casing. However, normally it is necessary to pull the 9-5/8" casing (if it is not pulled in the previous section) and continue to pull the 13-3/8" casing to establish a full cross section barrier inside well. And finally, install bridge plug as a base and continue with cement establishment.

4.2.5. Remove Upper Part of Conductor, Wellhead, and Casing Strings

The last step of the permanent P&A operation is to remove the upper part of conductor, wellhead, and casing strings. According to NORSOK D-010 [22], the wellhead and casings shall be removed below the seabed at a depth which ensures no stick up in the future. The traditional method for this operation is by use of cutting knives. Another option is to use explosives. In this latter method, measured has to be taken so that the risk of the operation can be minimized. A newer technology, abrasive water jet technology is becoming popular in the industry. The technology enables cutting of casing, tubing, and also control line simultaneously. Moreover, the technology can be used with LWI vessel.

Figure 4-4 illustrates the principle of the abrasive water jet cutting method. The water is pressurized between 60 MPa and 120 MPa, abrasive particles are added and pumped through a nozzle. This will create a high kinetic energy of abrasive water jet that can cut through 7" casing all the way out to a 36" conductor [29].

The cutting tool assembly consists of a special built wellhead connector and a stinger with the cutting nozzle at the bottom. The water jet cutter is lowered using heave compensated crane through the moonpool to the required depth where it performs the multistring cut. When the wellhead is cut it can be lifted and recovered by the special built wellhead connector [29].

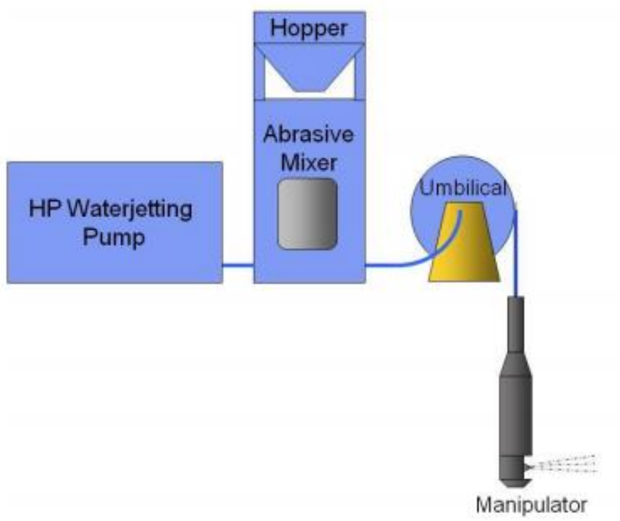


Figure 4-4 The Principle of Water Jet Cutting [29]

4.3. P&A Phases

According to Oil & Gas UK – Guideline on Well Abandonment Cost Estimation, the abandonment of any well could be divided into three phases that reflect the work-scope, equipment required, and/or the discrete timing of the different phases of work [30]. Within this master thesis, the following phases of P&A operation are occasionally used.

4.3.1. Phase 1 – Reservoir Abandonment

This is the phase of P&A operation where primary and secondary permanent barriers are established to isolate all reservoir producing or injecting zones. The tubing may be left in place, partly or fully retrieved. This phase is completed when the reservoir is fully isolated in compliance with the requirements.

In P&A general operational sequence that has been previously described in chapter 4.2, this phase is completed after the reservoir barrier has been established.

4.3.2. Phase 2 – Intermediate Abandonment

This phase usually includes casing pulling (or milling), the establishment of intermediate barriers to isolate potential hydrocarbon, and surface barrier installation. The tubing may be partly retrieved, if not already performed in Phase 1. This phase is completed when all of the barriers are set.

4.3.3. Phase 3 – Wellhead and Conductor Removal

This is the last phase where the retrieval of wellhead, conductor, and following casings are cut at some depth and retrieved to the surface. This phase is completed when no further operations are required for the well.

4.4. P&A General Challenges

Well plug and abandonment operation possesses several challenges. Furthermore, the operation is time-consuming and very expensive. The industry is currently searching for new technologies and methods to simplify the P&A operation. The main goal is to make the operation in the most cost-effective way because this operation has no value creation. Within this chapter, the general challenges of P&A operation are briefly described.

4.4.1. Rigs Availability

Conventionally, P&A operations are performed by a rig because it needs several 'heavy work' operations such as pulling tubing and casing milling. However, rig is very expensive. It is not cost-wise to use rigs to perform P&A activity. Moreover, with the huge amount of P&A activity ahead of us, the number of rigs will not be sufficient to perform the activity. Rigs should do their main purpose, which is to drill. Therefore, it is time to move the P&A activity from rigs to smaller vessels.

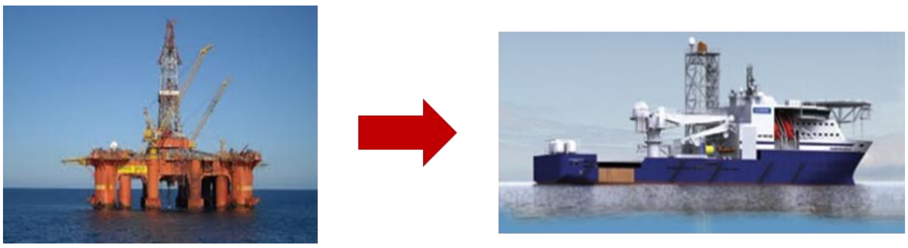


Figure 4-5 Move P&A Activities From Rig to Vessel

In this thesis, the option to use LWI vessel to perform a complete P&A activity is reviewed.

4.4.2. Missing Technologies

Another obstacle in current P&A operation is there are some 'missing technologies' that makes the activity complex and time consuming. Some of the missing technologies are logging tools that are able to log multiple casings and technology to cut control lines for a specific interval (50 – 100 meter).

4.4.2.1. Logging Through Multiple Casings

For verification of cement quality inside of the annulus, conventionally logging has been used. However, currently there is no technology to log through two or more casings. This prevents the ability to obtain information of cement quality behind the casings. Hence, today's common practice is to pull tubing and casing to log the relevant cement status, thus making the P&A operation complex. Currently, rig is used to pull the tubing and casing.

If one could 'see' through multiple casings and obtain information about cement quality behind casings, this may save the companies from placing unnecessary plugs. However, there are several companies working to solve the challenge. Existing technologies are being improved and there is also new technology being developed to overcome the challenge.

4.4.2.2. Control Lines Removal

The majority of subsea wells have control lines outside of the production tubing down to a valve or an instrumental piece of equipment. It facilitates remotely monitoring and control of the wells. However, the cables may become vertical leak path sources if they are left in the well. And currently, there is no available technology in the market to cut a specific interval of those lines for barrier establishment. Thus, it becomes necessary to pull the whole tubing with the lines attached.

4.4.3. Casing Removal

In P&A operation, the barrier needs to cover the whole cross section of the wellbore, like shown in Figure 4-3. However, in many cases it is difficult to place an approved barrier over the desired interval. The cement behind casing may have low quality due to poor cement jobs when the well was drilled. While in the other cases the cement may be missing altogether. Therefore, the casing and the poor cement need to be removed so that proper barrier can be set. The conventional way to deal with this problem is by section milling. Figure 4-6 illustrates the milling operation.

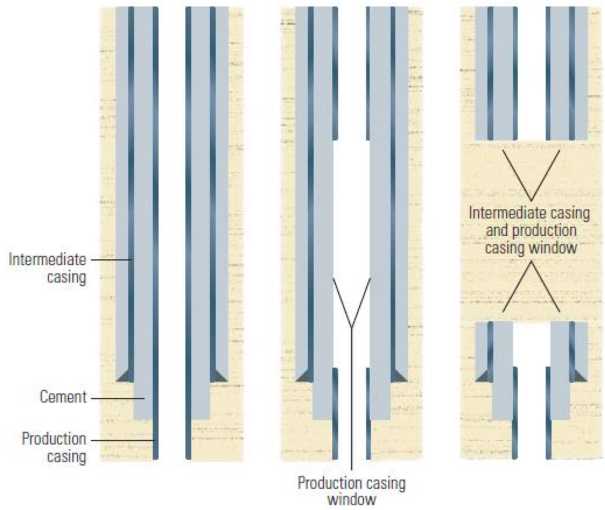


Figure 4-6 Casing Milling Operation [27]

4.4.3.1. Section Milling

Section milling is a process where some interval of the casing is removed/cut by knives or blades. The goal of section milling is to remove an interval of the casing along with everything behind it to create a section of clear area in the entire cross section of the wellbore for the barrier establishment. In section milling, the tool is run into the well to the desired depth. Once at the desired depth, a pressure is applied hydraulically, to make a cone exert force on the knives as shown in Figure 4-7. This will extend the knives to facilitate milling operation. Applying a rotational force, the tool will then make a cut in the casing body, and once the cut is completely through it, the milling is commenced. The milling is usually done in a downward motion, meaning that the weight applied from the drillstring is what pushes the milling tool down [31].

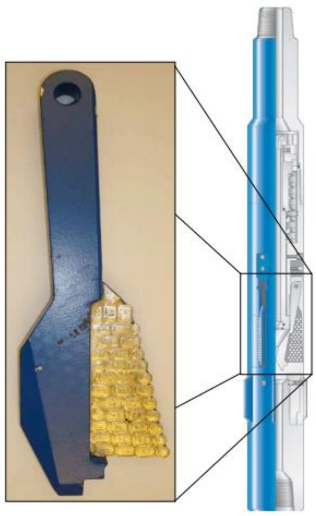


Figure 4-7 Section Milling Tool and Cutter [32]

Section milling is an unpopular operation during P&A activity. This is caused by several reasons:

1. It is a time-consuming operation. This will lead to high cost.
2. Swarf generation. Swarf is used to describe the cuttings or metal shavings that are generated under the milling operations. It is difficult to handle and can cause serious problems downhole. It also can harm critical equipment like the BOP when circulated out.
3. The excessive vibrations can damage equipment in the BHA.

Nevertheless, there are several modern technologies that avoid section milling operations during P&A activity. They are discussed in chapter 6.

4.4.4. Poor Documentation of Old Wells

Normally, the wells to be permanently plugged and abandoned are old wells. Most of them do not have sufficient information or data regarding the well status. Complete well data is needed to plan and perform the P&A operation. Especially the information regarding the cement quality inside of the annulus. This can cause a major problem because extra work must be executed to investigate and obtain the required well information.

5. Rules and Regulations of P&A Operations

This chapter gives a brief overview of how different regulations standardize the P&A activity in different offshore regions. There are three regulations that are described. NORSOK D-010 as the NCS regulation; Guidelines for the suspension and abandonment wells, from Oil & Gas UK, for UKCS; and a regulation from US Bureau of Safety and Environmental Enforcement (BSEE) for the Gulf of Mexico.

5.1. NORSOK D-010, rev. 4 2013

The NORSOK standards are developed by the Norwegian petroleum industry as a part of the NORSOK initiative and supported by the Norwegian Oil and Gas Association and the Federation of Norwegian Industries [22].

This standard defines requirements and guidelines relating to well integrity in drilling and well activities. Well integrity is defined to be “application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well”. The standard focuses on establishing well barriers by use of WBE’s, their acceptance criteria, their use and monitoring of integrity during their life cycle. The standard also covers well integrity management and personnel competence requirements. The standard does not contain any well or rig equipment specifications [22].

Figure 5-1 represents the “road map” of NORSOK D-010 to get a quick overview of the structure of this standard and related requirements and guidelines.

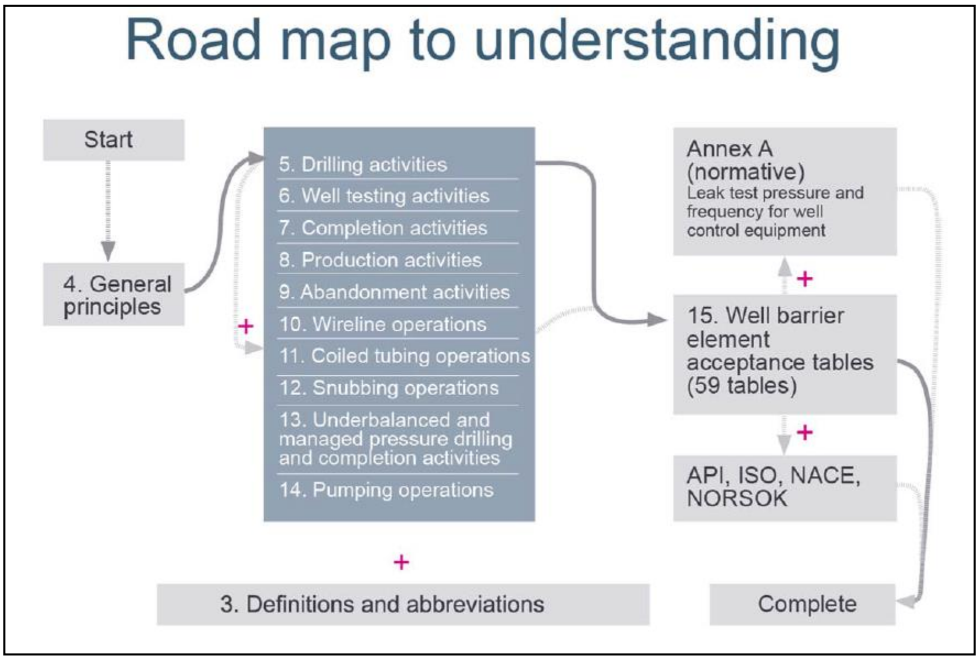


Figure 5-1 Road Map to Understanding NORSOK D-010 [22]

Based on the “road map” above, the person who plan and design any well activities (number 5 to 14 in Figure 5-1) is responsible for ensuring the well integrity by establishing well barriers that meet the minimum requirements of the standard.

5.1.1. Abandonment Activities

There are four abandonment activities according to NORSOK D-010 [22]:

1. suspension of well activities and operations,
2. temporary abandonment,
3. permanent abandonment,
4. permanent abandonment of a section in a well (sidetracking, slot recovery) to construct a new wellbore with a new geological well target.

Within the next subsections, the requirements of abandonment activities according to NORSOK D-010 are discussed.

5.1.2. Temporary Abandonment

Temporary abandoned wells are defined as all wells/all wellbores except all active wells and wells that are permanently plugged and abandoned according to the regulations. Active wells are defined as production/injection wells that are currently producing or injecting. This should include both platform and subsea wells [33].There are several reasons why a well needs to be temporarily abandoned such as [34]:

- during a long shut-down,
- when pulling the BOP for a repair,
- when skidding rig to do higher priority well work,
- while waiting for a work over,
- while waiting for field development or redevelopment,
- when converting a well from an exploration to a development well,
- re-entry at a later stage to perform sidetrack.

According to NORSOK D-010 [22], temporary abandonment is divided into:

1. Temporary Abandonment – with monitoring:
   Well status where the well is abandoned and the primary and secondary well barriers are continuously monitored and routinely tested. There is no maximum abandonment period for wells with monitoring.
2. Temporary Abandonment – without monitoring:

Well status, where the well is abandoned and the primary and secondary well barriers are not continuously monitored and not routinely tested. The maximum abandonment period shall be three years.

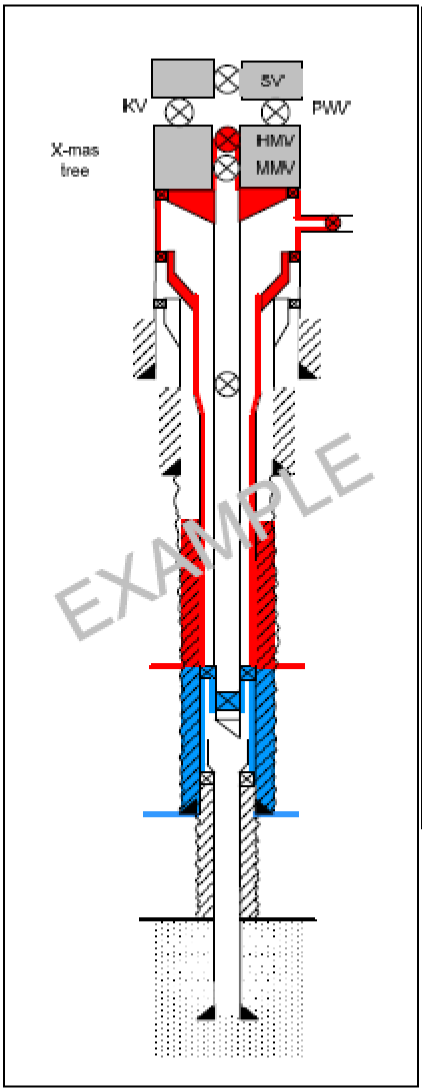
5.1.2.1. Well Barrier Acceptance Criteria – Subsea Wells

For subsea wells, every temporarily abandoned wells shall be protected from external loads in areas with fishing / trawling activities, or other seabed activities. Another important thing is a yearly inspection program shall be performed for all of the subsea wells that are not tied back to a production facility thus preventing monitoring. There are several requirements that need to be fulfilled prior to abandon the well temporarily [22]:

1. Production/injection packer and tubing hanger is pressure tested.
2. Tubing is pressure tested.
3. The DHSV is closed and pressure/function tested.
4. All valves in the subsea tree are pressure/function tested and are closed.
5. For wells with horizontal subsea tree, the tubing hanger crown plug(s) is pressure tested.

5.1.2.2. WBS Example

Inside of the NORSOK D-010, there are several examples of how a well can be temporarily abandoned. Figure 5-2 shows one of the scenario of it. The two minimum well barriers are shown using red and blue color.



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement (up to prod packer)	22	
Casing (up to prod packer)	2	
Production packer	7	
Deepset plug	6	
Secondary well barrier		
In-situ formation (at prod packer)	51	
Casing cement (above prod packer)	22	
Casing	2	
Casing hanger (with seal assembly)	5	
Annulus access valve	17	
Tubing hanger (with seals)	10	
Surface production tree valves/connector	31	
Surface production tree body	31	

Figure 5-2 Production Well with Deep Set Mechanical Plug, Continuous Monitoring [22]

Although there are a lot of scenarios of how a well is temporarily abandoned, the main important thing is that they can be re-entered in a safe manner, either to convert it into a permanent abandoned well, or for another reason.

5.1.3. Permanent Abandonment

Permanent abandonment is defined in NORSOK D-010 as a well status, where the well is abandoned and will not be used or re-entered again [22]

One of the most important requirements for permanent well barriers is that it shall extend across the full cross section of the well, including all annuli and seal both vertically and horizontally as illustrated in Figure 5-3. Therefore, removal of downhole equipment is also required because it can create a vertical leak path.

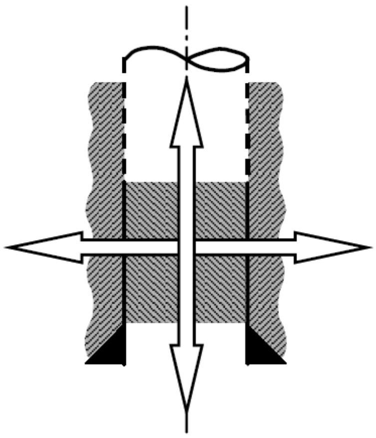


Figure 5-3 A Permanent Well Barrier Shall Cover the Full Cross Section of The Well [22]

NORSOK D-010 also states that permanently abandoned wells shall be plugged with an eternal perspective taking into account the effects of any foreseeable chemical and geological processes. A permanent well barrier element must have the following characteristics [22]:

- provide long-term integrity (eternal perspective),
- impermeable,
- non-shrinking,
- able to withstand mechanical loads/impact,
- resistant to chemicals/ substances (H_2S, CO_2, and hydrocarbons),
- ensure bonding to steel,
- not harmful to the steel tubulars integrity.

Those characteristics are required to make sure that a proper and efficient barrier element is established so that no hydrocarbon fluids can migrate to the surface.

When completion tubulars are left in the well and WBE are installed in the tubing and annulus, the position and integrity of these shall be verified:

1. The casing cement between the casing and tubing shall be verified by pressure testing.
2. The cement plug (inside tubing) shall be tagged and pressure tested

Another requirement is to remove well equipment above the seabed. The wellhead and casings have to be removed at a depth which ensures no stick up in the future. Required cutting depth shall be sufficient to prevent conflict with other marine activities. However, for deep water wells (>600 m water depth) it may be acceptable to leave or cover the wellhead/structure. The last thing to do is to inspect the location to make sure that there is no equipment left behind on the seafloor.

5.1.3.1. Position of The Plugs

NORSOK D-010 states that the well barrier(s) shall be placed adjacent to an impermeable formation with sufficient formation integrity for the maximum anticipated pressure [22]. Thus, the setting depth of the permanent plug is dependent on the pressures and fluids in the formations. Table 5-1 shows the required well barrier depth position.

Table 5-1 Well Barrier Depth Position [22]

Name	Function	Depth Position
Primary well barrier	To isolate a source of inflow, formation with normal pressure of over-pressured/impermeable formation from surface/seabed	The base of the well barriers shall be positioned at a depth where formation integrity is higher than potential pressure below
Secondary well barrier	Back-up to the primary well barrier, against a source of inflow	As above
Crossflow well barrier	To prevent flow between formations (where crossflow is not acceptable). May also functions as primary well barrier for the reservoir below	As above
Open hole to surface well barrier	To permanently isolate flow conduits from exposed formation(s) to surface after casing(s) are cut and retrieved and contain environmentally harmful fluids. The exposed formation can be over-pressured with no source of inflow. No hydrocarbons present	No depth requirement with respect to formation integrity

Based on the table above, the integrity of the formation around the well has to be known before performing P&A operation, so that we know how much pressure it can withstand. There are several methods to find and test formation integrity Inside of the wellbore. However, it will not be discussed in this thesis.

In some cases, the wellbore may go through multiple reservoir zones. The plugs must be established in each of the reservoir zones. However, there are cases when the multiple reservoir zones located within the same pressure regime. According to NORSOK D-010, it can be regarded as one reservoir, for which a primary and secondary well barrier must be installed as shown in Figure 5-4.

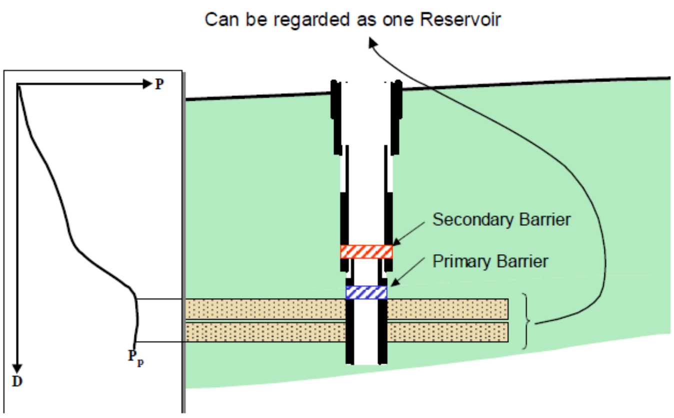


Figure 5-4 Multiple Reservoirs Within The Same Pressure Regime [22]

5.1.3.2. Length Requirement

NORSOK D-010 divides the WBE for permanent P&A into two, external WBE and internal WBE. The external WBE is the casing cement while the internal WBE is the cement plug. To ensure that both of the WBEs have sufficient sealing criteria, NORSOK D-010 suggests length requirement for both of them.

According to NORSOK D-010, the requirement for an external WBE is 50 m with formation integrity at the base of the interval. If the casing cement is verified by logging, a minimum of 30 m interval with acceptable bonding is required to act as a permanent external WBE. For internal WBE, the plug shall be positioned over the entire interval (defined as a well barrier) where there is a verified external WBE and shall be minimum 50 m if set on a mechanical plug/cement as a foundation, otherwise according to EAC 24 [22].

EAC 24 above means the Element Acceptance Criteria (EAC) for table 24, which is the cement plug criteria. The criteria are summarized in Table 5-2 below.

Table 5-2 Length Criteria for a Cement Plug (MD=Measured Depth)

Open Hole Cement Plugs	Cased Hole Cement Plugs	Open Hole to Surface Plug (Installed in surface casing)
100 m MD with minimum 50 m MD above any source of inflow/leakage point. A plug in transition from open hole to casing should extend at least 50 m MD above and below casing shoe.	50 m MD if set on a mechanical/cement plug as foundation, otherwise 100 m MD	50 m MD if set on a mechanical plug, otherwise 100 m MD

Besides the criteria that are shown in Table 5-2 above, there are other requirements for the length of the plug to be a qualified WBE:

1. Placing one continuous cement plug in a cased hole is an acceptable solution as part of the primary and secondary well barriers when placed on a verified foundation (e.g. pressure tested mechanical/cement plug).
2. Placing one continuous cement plug in an open hole is an acceptable solution as part of the primary and secondary well barriers with the following conditions:
   - The cement plug shall extend 50 m into the casing.
   - It shall be set on a foundation. The cement plug(s) shall be placed directly on top of one another.

5.1.3.3. Verification

Every WBEs must be verified to make sure they have sufficient sealing properties. How the barrier is tested depends on the type of the barrier itself. NORSOK D-010 gives recommendation to verify and test every WBEs. However, the area of interest for P&A WBE's is cement plug (internal WBE) and cement casing (external WBE).

<u>Cement Plug</u>

Several actions should be taken to verify the cement [22]:

1. Cased hole plugs should be tested either in the direction of flow or from above.
2. The strength development of the cement slurry should be verified through observation of surface samples from the mixing, cured on site in representative temperature.
3. The plug installation shall be verified through evaluation of job execution taking into account estimated hole size, volumes pumped and returns.
4. The plug shall be verified by:
   - Open hole: Tagging
   - Cased hole: Tagging

     Pressure test, which shall:

     a) be 70 bar (1000 psi) above estimated leak off pressure (LOT) below casing/ potential leak path, or 35 bar (500 psi) for surface casing plugs; and

     b) not exceed the casing pressure test and the casing burst rating corrected for casing wear.

     If the cement plug is set on a pressure tested foundation, a pressure test is not required. It shall be verified by tagging.

Casing cement

The cement length shall be verified through logs or 100% displacement efficiency based on records from the cement operation (volumes pumped, returns during cementing, etc.). Actual displacement pressure/volumes should be compared with simulations using industry recognized software. The cement sealing ability shall be verified through a formation integrity test [22].

Furthermore, to be a qualified WBE, the actual cement length shall be:

1. above a potential source of inflow/ reservoir;
2. 50 m MD verified by displacement calculations or 30 m MD when verified by bonding logs. The formation integrity shall exceed the maximum expected pressure at the base of the interval.
3. 2 x 30m MD verified by bonding logs when the same casing cement will be a part of the primary and secondary well barrier.
4. The formation integrity shall exceed the maximum expected pressure at the base of each interval.
5. For wells with injection pressure exceeding the formation integrity at the cap rock: The cement length shall extend from the uppermost injection point to 30 m MD above top reservoir verified by bonding logs.

5.1.3.4. Examples of Permanent Abandonment Options

In this section, some examples of how a well can be plugged are shown. Some of the examples will show the summary of NORSOK D-010 P&A requirement that were previously described.

Single Cement Plug in Combination with Mechanical Plug

Figure 5-5 shows a permanently plugged well by setting a mechanical plug to serve as a foundation for a single cement plug. The internal cement plug length covers the logged interval in the annulus.

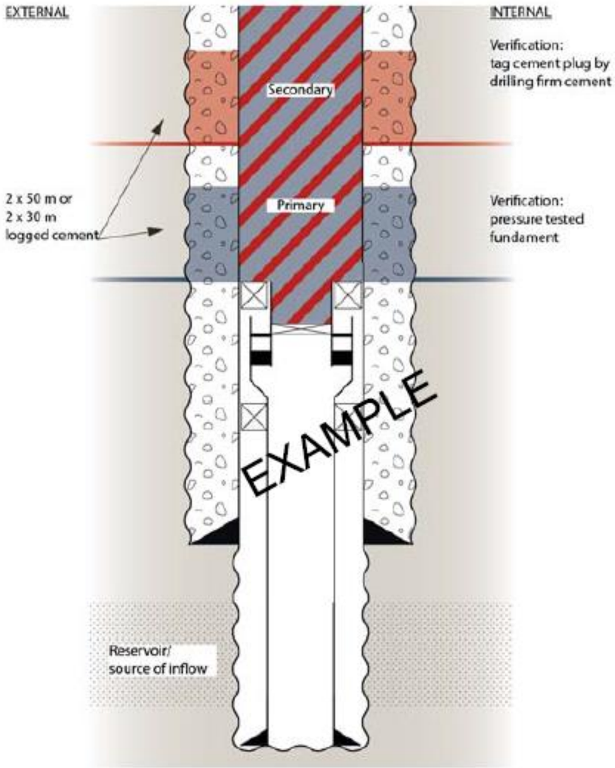


Figure 5-5 Permanent Abandonment, Single Cement Plug with Mechanical Plug Foundation [22]

In this example, the casing cement has to be verified minimum 2 x 30 m by cement bonding logs to see the proper cement placement and quality between the well casing and the formation. While the internal plug, which is the cement plug, can be combined as a single cement plug with mechanical plug as a foundation. The internal plug is verified by pressure test.

<u>Section Milling Examples</u>

Figure 5-6 shows two examples of how section milling is usually done in a P&A operation. In this example, the cement quality in the annulus is not good, thus, the casing has to be milled. There are two examples ways of how to plug the well, with a single cement plug and two separate plugs.

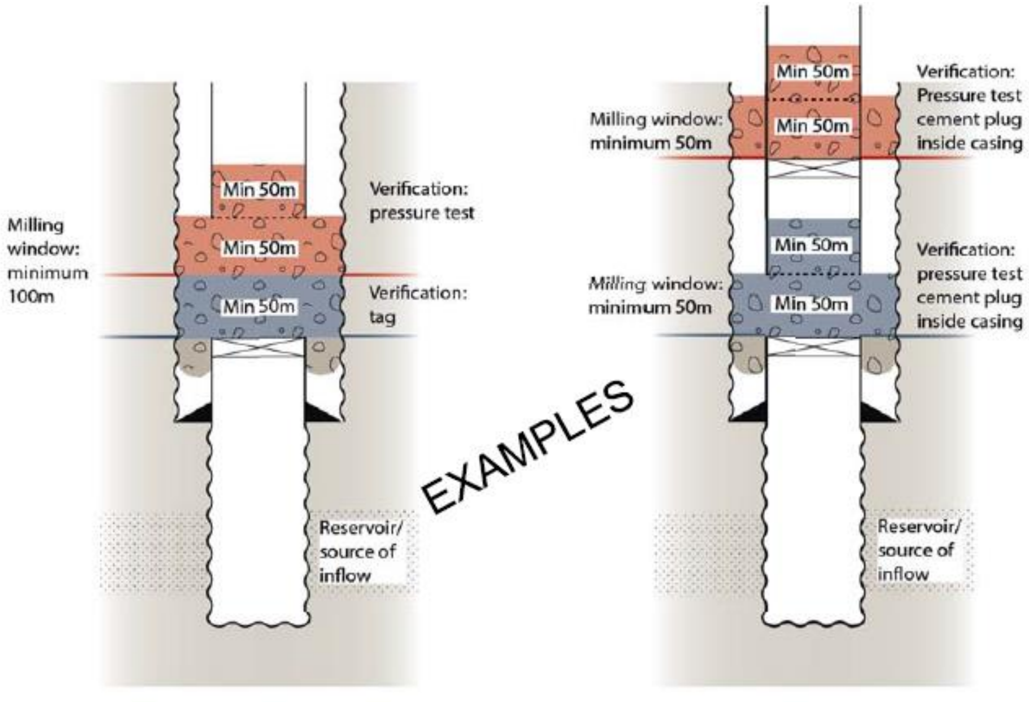


Figure 5-6 Section Milling Examples [22]

For the left one (continuous single plug), the casing is milled 100 m. Mechanical plug is installed as a foundation of the cement plug. 50 m of primary cement plug is established, then verified by tagging. While the secondary plug must have 50 m in the open hole, and extend 50 m inside the casing. Pressure test then can be done to verify the plug because they extend inside the casing.

In two separate plugs, the casing is milled twice for 50 m each. Then the procedure is the same with the continuous plug. However, the both of primary and secondary barrier plug must extend another 50 m inside the casing.

5.2. Oil & Gas UK - Guideline for The Suspension and Abandonment of Wells

The United Kingdom (UK) has their own standard regarding the well P&A activity within UKCS. The objective of the document is to provide guidelines for the isolation of permeable zones when a well is abandoned, or suspended with a view to re-entry or later abandonment, in compliance with current UK legislation [35]. The guidelines provide minimum criteria to ensure full and adequate isolation during P&A activity.

In this section, the Issue 4 of this standard that has been published in 2012 is discussed. The structure of the UK guideline is different from NORSOK D-010. However, the main requirements of the document will be described.

5.2.1. Definitions

Before describing the guidelines, the definition of general terms used in the guideline are presented.

Permanent Abandonment

The action taken to ensure the permanent isolation from surface and from lower pressured zones, of exposed permeable zones, fluids and pressures in any well that will not be re-entered.

Permanent Barrier

A verified barrier that will maintain a permanent seal.

Permeable Zone

Any zone in the well where there is the possibility of fluid movement on application of a pressure differential.

Distinct Permeable Zone

A group of permeable zones that were originally within the same pressure regime, and where uncontrolled flow between subzones can be shown to be acceptable. For example, where:

1. It will not create a change in pressure control requirements; and
2. It will not have an adverse effect on reservoir management; and
3. It will not result in 'contamination' of fluids in one of the subzones i.e. freshwater

5.2.2. Requirements of Permanent Barriers

Within this section, the general requirements of how P&A operation should be done are briefly discussed. Figure 5-7 illustrates the 'ideal' schematic of permanent barrier.

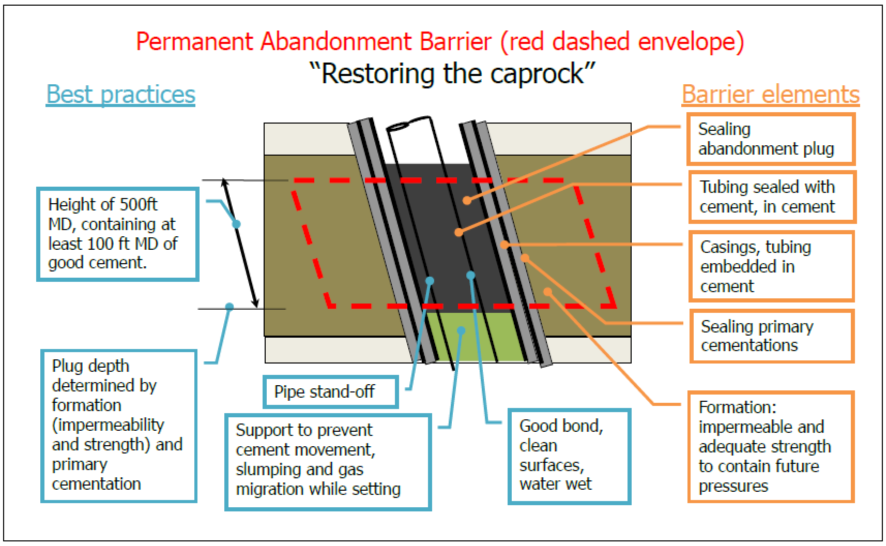


Figure 5-7 Schematic of a Permanent Barrier [35]

5.2.2.1. Number of Permanent Well Barriers

The guideline regulates the number of barriers that should be established in P&A activity:

- Two permanent barriers from surface or seabed are required if a permeable zone is hydrocarbon-bearing or over-pressured and water-bearing. The second permanent barrier is a backup to the first.
- The two permanent barriers may be combined into one single large permanent barrier in case it is possible.

5.2.2.2. Position

The UK guideline states that the first barrier should be set across or above the highest point of potential inflow (top permeable zone or top perforations, whichever is shallower), or as close as reasonably possible. If installed inside casing or liner it should be lapped by annular cement [35].

The second barrier (when required) should work as a backup to the first barrier. However, the second barrier can be the primary barrier for another, shallower positioned, permeable zone. The general requirements are illustrated in Figure 5-8 .

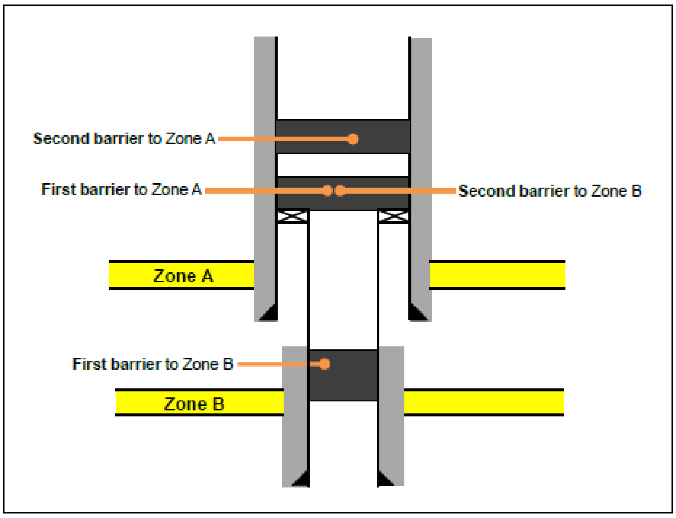


Figure 5-8 General Requirements for Well Abandonment [35]

5.2.2.3. Length

For barrier length, the guideline gives several requirements [35]:

- A barrier of at least 100 ft (30.48 m) measured depth (MD) of good cement is considered good industry practice. Generally, a 500 ft (152.5 m) MD barrier should be installed if possible.

- The top of the first barrier should extend at least 100 ft MD above the highest point of potential inflow.
- If two distinct permeable zones are less than 100 ft apart, then a 100 ft MD column of good cement below the base of the upper zone is sufficient.
- If casing is part of permanent barrier, at least 100 ft MD of good cement in annulus adjacent to the internal plug is required.
- When a combination permanent barrier replaces two separate barriers, a column of 200 ft MD good cement (61 m) is recommended. Generally, an 800 ft MD (244 m) barrier is set in this case.

Figure 5-9 illustrates the summary of the length requirement for permanent barriers.

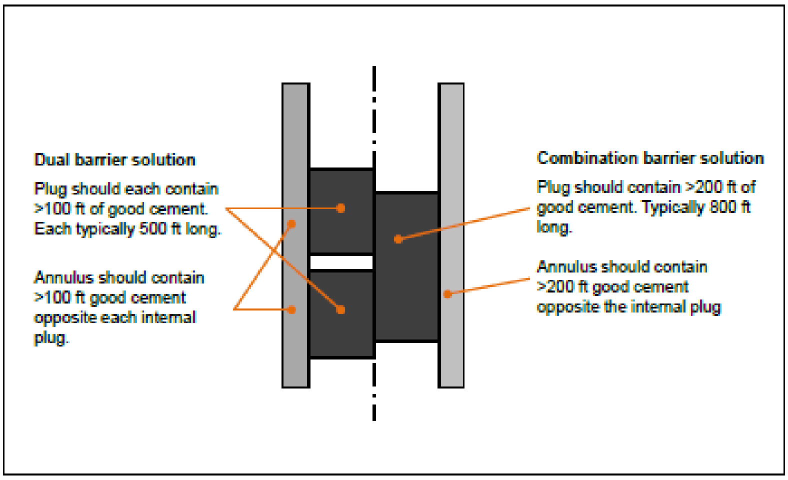


Figure 5-9 Length Requirement [35]

5.2.2.4. Verification

The Oil & Gas UK guideline describes some methods of how permanent barriers should be verified to ensure that it is installed as per requirement.

<u>Cement Plug</u>

The cement barrier should be verified by the following [35]:

- The barrier installation should be documented
- The strength development of the cement slurry should be confirmed.
- The position of a barrier should be verified by tagging, or by measurement to confirm the depth of the firm cement plug.
- The cement plug should be verified:
    - Open hole: Weight test
        - On drillpipe is typically 10 to 15 klbs

        - On wireline, coiled tubing or stinger this weight will be limited by tools and geometry
    - Cased hole: Documented pressure or inflow test
- A pressure test should be a minimum of 500 psi above the injection pressure below the barrier but not exceed the casing strength.

Casing Cement

The position (TOC) of the annular cement should be verified by:

- Logs
- Estimation on the basis records from the cement operation

Moreover, the sealing capability of the casing cement should also be assessed. The evidence of the assessment may be from logs, absence of sustained casing pressure during the life cycle of the well, absence of anomalies, etc.

In the document, the guidance on verification is shown in some tables to help clarify the intent of the verification requirements. However, it will not be discussed further in this thesis because it is not the main objective of this thesis.

5.2.2.5. Other Considerations

Removal of downhole equipment

According to the guideline, the removal of downhole equipment is not a requirement as long as the isolation outlined in the guidelines are achieved [35].

Control lines, ESP cables, gauge cables

Cables and control lines should not be part of the permanent barriers as they may be a potential leak path.

Through-tubing abandonments

When well completion tubulars are left in the hole and permanent barriers are to be installed through and around the tubular, the guideline states that reliable methods and procedures to install and verify the position of the barrier should be established. Figure 5-10 shows an example of through-tubing P&A.

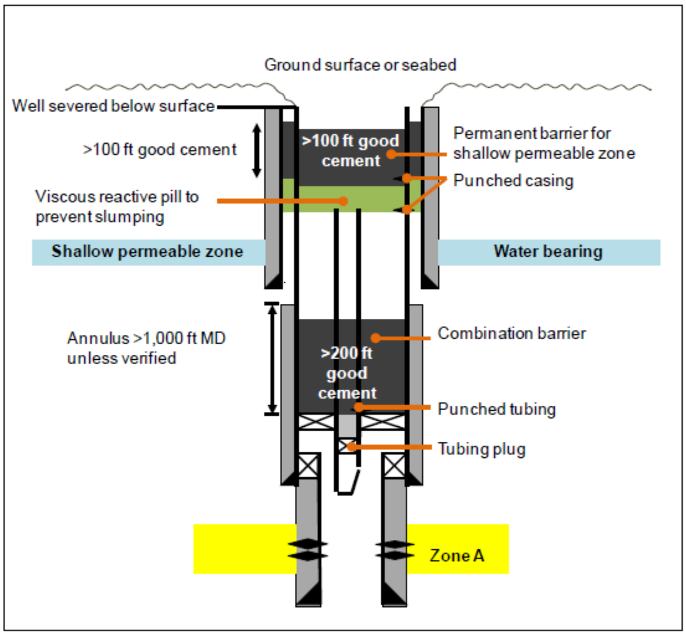


Figure 5-10 Example of Through-tubing Cased Hole Abandonment [35]

Since currently there is no accurate method of determining TOC in both tubing and annulus, the guideline states that a method of tagging combined with quality control of cement placement and pressure testing both annulus and tubing can be used to confirm the presence of a permanent barrier.

Removal of subsea equipment

The good practice stated in the guideline is to retrieve all casing string to a minimum of 10 ft (3.05 m) below the seabed. This requirement mainly exists to accommodate fishing activities in the area after the well has been abandoned [35].

5.3. US Bureau of Safety and Environmental Enforcement (BSEE)

For Gulf of Mexico subsea wells, the regulation of how to permanently plugged and abandoned a well is regulated by US Bureau of Safety and Environmental Enforcement (BSEE) section §250.1710 – §250.1723. This regulation sets the P&A requirements depending on a well's location, depth, condition and other parameters for the area. Table 5-3 shows the BSEE guideline for P&A activity in the Gulf of Mexico.

Table 5-3 US P&A Regulations Guide [36]

Situation	Procedure
Zones in open hole	Cement plug(s) set from at least 100 ft (30 m) below the bottom to 100 ft above the top of oil, gas, and fresh-water zones to isolate fluids in the strata.
Open hole below casing	Perform one of the following: - Set, by the displacement method, a cement plug at least 100 ft above and below deepest casing shoe. - Set a cement retainer with effective back-pressure control set 50 ft (15 m) to 100 ft above the casing shoe, and a cement plug that extends at least 100 ft below the casing shoe and at least 50 ft above the retainer. - Set a bridge plug set 50 to 100 ft above the shoe with 50 ft of cement on top of the bridge plug, for expected or known lost circulation conditions.
Perforated zone that is currently open and not previously squeezed or isolated	Perform one of the following: - Use method to squeeze cement to all perforations. - Set, by the displacement method, a cement plug at least 100 ft above to 100 ft below the perforated interval, or down to a casing plug, whichever is less. - If the perforated zones are isolated from the hole below, use any of the five plugging methods specified below instead of the two specified in this section, immediately above. ▪ Set a cement retainer with effective back-pressure control set 50 to 100 ft above the top of the perforated interval, and a cement plug that extends at least 100 ft below the bottom of the perforated interval with at least 50 ft of cement above the retainer. ▪ Set a bridge plug set 50 to 100 ft above the top of the perforated interval and at least 50 ft of cement on top of the bridge plug. ▪ Set, by the displacement method, a cement plug at least 200 ft (60 m) in length, with the bottom of the plug no more than 100 ft above the perforated interval ▪ Set a through-tubing basket plug set no more than 100 ft above the perforated interval with at least 50 ft of cement on top of the basket plug. ▪ Set a tubing plug set no more than 100 ft above the perforated interval topped with a sufficient volume of cement so as to extend at least 100 ft above the uppermost packer in the wellbore and at least 300 ft (90 m) of cement in the casing annulus immediately above the packer.
Casing stub where the stub end is within the casing	Perform one of the following: - Set a cement plug at least 100 ft above and below the stub end.

Situation	Procedure
	- Set a cement retainer or bridge plug set at least 50 to 100 ft above the stub end with at least 50 ft of cement on top of the retainer or bridge plug. - Set a cement plug at least 200 ft long with the bottom of the plug set no more than 100 ft above the stub end.
Casing stub where the stub end is below the casing	Set a plug as specified in the open hole sections, above, as applicable.
Annular space that communicates with open hole and extends to the mud line	Set a cement plug at least 200 ft long set in the annular space. For a well completed above the ocean surface, pressure test each casing annulus to verify isolation.
Subsea well with unsealed annulus	Use a cutter to sever the casing; set a stub plug as specified in casing stub sections, above.
Well with casing	Set a cement surface plug at least 150 ft (45 m) long set in the smallest casing that extends to the mud line with the top of the plug no more than 150 ft below the mudline.
Fluid left in the hole	Maintain fluid in the intervals between the plugs that is dense enough to exert a hydrostatic pressure that is greater than the formation pressures in the intervals.

Verification

For barrier verification, test of the first plug below the surface plug and all plugs in lost circulation areas that are in open hole should be done. The plug must pass one of the following tests to verify plug integrity:

1. A pipe weight of at least 15,000 pounds on the plug; or
2. A pump pressure of at least 1,000 pounds per square inch. The pressure should not drop more than 10 percent in 15 minutes.

Removal of wellheads and casings

The regulation states that all wellheads and casings must be removed for at least 15 ft (5 m) below the mudline. However, alternate removal depth may be approved for one of the following reasons:

- The water depth is greater than 800 m.
- The wellhead or casing would not become an obstruction to other users of the seafloor.
- There is a big safety concern relating to the removal activity.

5.4. Comparison of Plug & Abandonment Regulatory Requirements

Until today, there is no standardized document of regulation for plug & abandonment operation. Different regions have different regulations as discussed in this chapter. However, despite the disparities between regulators around the world, the intent of all P&A operations is to prevent migration of hydrocarbon to surface.

Because the main objective for this thesis is not to compare the regulations, only the main requirement, which is the plug length and method of verification that are summarized in Table 5-4.

Table 5-4 Well Barrier Regulation Comparison Between Regulations [37]

	Norwegian Regulations	**UK Guideline**	**Gulf of Mexico Requirements**
Zones in OH reservoir	50 - 100 m above	100 ft above and below	100 ft above and below
Cased hole plug	50 m if above mechanical plug, otherwise 100 m	100 ft of good cement, otherwise 500 ft	200 ft length with minimum 100 ft above perforated interval
Transition from cased to open hole	100 m or 50 m above casing shoe	100 ft of good cement, otherwise 500 ft	100 ft above and below casing shoe
Verification method	Open hole: tagging Cased hole: tagging and pressure test (1000 psi above LOT)	10 - 15 klbs weight (drillpipe) or 500 psi above injection pressure	15 klbs weight or 1000 psi pressure test

6. P&A Operation Using LWI Vessel

In this chapter, the challenges of doing P&A operation using LWI vessel are discussed, followed by the proposed technologies and methods as the solutions.

6.1. Challenges of P&A Operations Using LWI Vessel

Besides the general challenge of P&A operation that has been explained in section 4.4, there are also some challenges of doing P&A operation using LWI vessel. Based on literature study, the main challenges of performing P&A using LWI vessel can be summarized in Figure 6-1. Those main challenges are discussed in this chapter.

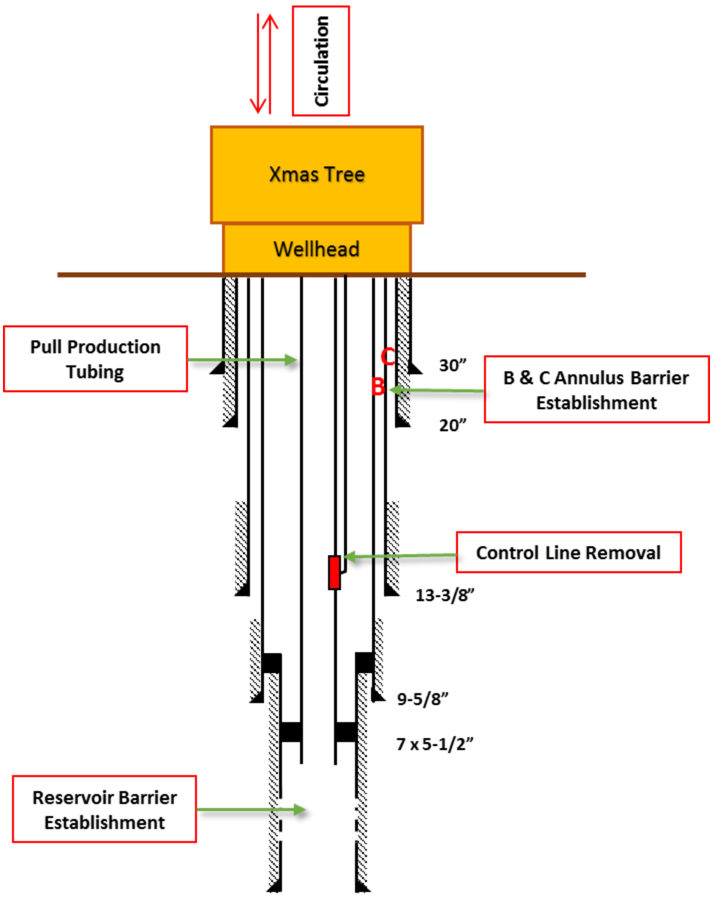


Figure 6-1 Challenges of P&A Operation with RLWI Vessel

6.1.1. Production Tubing Removal

As described in 4.2.2, the requirement to pull the tubing or not is based on several issues. Lack of integrity on the tubing usually makes it necessary to retrieve it. Another issue is to verify the condition of cement behind casing. Sometimes it is not verified, in a poor condition, or not present. Because currently there is no technology to log through multiple casings, the verification of cement behind casing is difficult. Thus, the tubing is necessary to be pulled. The other issue is the control lines that are clamped outside of the tubing as shown in Figure 6-2. The control lines are used for measuring, controlling, and regulating the well. When the barrier needs to be established, it should cover the entire cross section of the wellbore. The problem is that if cemented in, those control lines could lead to vertical leak paths inside the barrier. It means the control line should be removed to comply with regulation. Unfortunately, currently the only way to remove the control lines is by removing the entire tubing they are attached to.

Figure 6-2 Control Lines Outside The Tubing [38]

It is important to cut both tubing and control lines before pulling the production tubing. The reason is because it is impossible to control where the control lines outside tubing will break. The control lines can make unnecessary junk inside the well, and it will be difficult to retrieve it.

Because of those reasons above, conventionally the tubing is pulled out in P&A operation. It is a difficult operation, especially if the unit to do that is an LWI vessel. The main reason is because it is difficult to achieve well barrier minimum requirement. In a conventional way by rig, BOP is used with marine riser (21”) on top of it. Until today, there is no experience to perform this operation using an LWI vessel.

Therefore, the challenge is to find technology to either remove a section of the tubing or cut the control lines, thus eliminating the need to pull the tubing.

6.1.2. Reservoir Barrier Establishment and Circulation Path

Conventionally, the cement barrier is established using a semi-sub rig with drill pipe run in hole. Using marine riser as a circulation path, cement establishment can be easily done. The problem arises when LWI is used instead of rig. Because there is no circulation path in conventional tools on LWI vessel, it is more difficult to clean the well and place the cement. Therefore, the challenge is to find a way to establish reservoir barrier and also to establish circulation path from the vessel into the wellbore.

6.1.3. B & C Annulus Barrier Establishment

Phase 2 of permanent P&A usually starts after the production tubing is pulled and the reservoir isolation has been established. Generally, the next action is to log the cement behind the casing to see the condition of the cement in the annulus. However, as mentioned before, until today there are no tools commercially available to log multiple casing strings, thus it is difficult to check the condition of the cement inside the annulus. This can cause the necessity to mill the casing to create barrier in the entire cross section, inside the B & C annulus as shown in Figure 6-3. As explained before that milling is an undesirable operation. Furthermore, it is also a challenge to be done using RLWI vessel as the swarf created by milling operation should be handled.

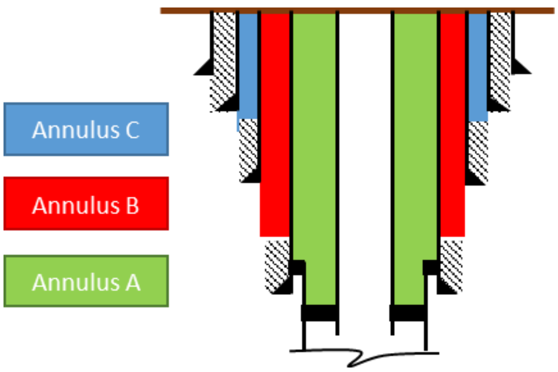


Figure 6-3 A, B, and C Annulus

6.2. Production Tubing Considerations

As discussed before, production tubing removal is one of the greatest challenges of P&A operation, especially if it is performed using an LWI vessel. The removal of control lines on the outside of production tubing is one of the reasons for pulling the production tubing.

However, it is important to note that the tubing does not necessarily need to be pulled. It could be left inside of the wellbore as long as the requirement of barrier establishment in the entire of the cross section could be achieved and verification could be done. In this section, the idea to leave the production tubing inside is discussed, followed by several concepts and methods related to pulling of tubing and control lines removal.

6.2.1. Tubing Left in Hole

A project has been done by DrillWell Research Center to see the possibility of leaving most of the production tubing in the well during the P&A operations. If most of the production tubing and the control lines can be left inside, it would save significant operation time. Besides the control lines that may create a vertical leak path, if the tubing is left inside it may also create another problem. The cement may not be able to properly displace the original fluid in the annulus outside of the tubing where the P&A plug is planned to be placed. Moreover, poor cement quality can result due to lack of centralization of the tubing [38]. Therefore, full-scale tests, with several assemblies of 7" tubings cemented in 9-5/8" casings, were performed to determine the sealing ability of annulus cement when the tubing is left in hole. The tests were performed with both conventional cement and expandable cement, and with and without control lines present. Figure 6-4 shows the example of the configuration on the experiment while the control cable used in the experiment is shown in Figure 6-5.

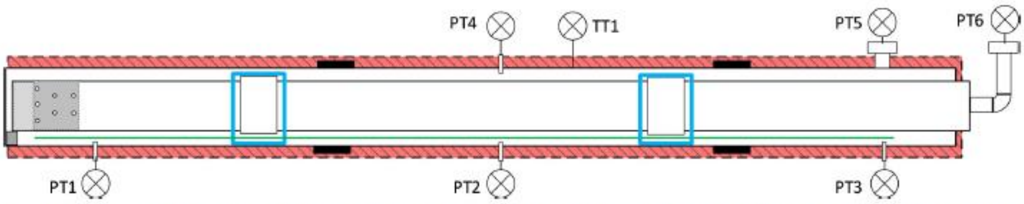


Illustration of Assembly B with conventional cement: Green line is control cable, blue rectangles are cable clamps, PT1–6 are pressure sensors, and TT1 is temperature sensor.

Figure 6-4 Schematic Illustration of One of the Assemblies [38]

The assemblies were provided with pressure sensors. The sensor ports also served as channels for water injection or leakage measurement. Then pressure tests with water were done to determine the quality of the cement, where leakage rates and pressure drops were recorded [38]

Figure 6-5 Control Cables Used in Tests [38]

The experiment demonstrated that it is possible to obtain good cement placement when the tubing is left in the hole. Visual inspection was also done by cutting the test assemblies at different places as can be seen in Figure 6-6.

Figure 6-6 Cut Test Assemblies Without Control Lines (left) and With Control Lines (right) [38]

It can be seen from the picture above that the lack of tubing centralization does not prevent cement placement in the annulus. In other words, the experiments show that it is possible to have cement well placed in the annulus also when the tubing is left in hole. Even though some micro-annuli were detected after the experiments, they are relatively small and also non-uniform. The micro-annuli will not create a large leak rate in real P&A operation because of the length of barrier (100 m) of the cemented annulus. Another important thing is the presence of control lines did not represent any additional leakage paths [38].

Comment

An idea to just leave the tubing inside could save P&A operation significantly. Some experiments have been done by DrillWell Research Center to see the possibility of it. However, in this experiment, the pumping of cement is relatively slow. Although it has been reported that such a slow pumping rate during cement placement has been used successfully in the field, it does not necessarily mean that this technique is applicable in a field since the annulus may be filled with a drilling fluid having more complex rheological performance [38]. Field test should be performed to prove whether this operation can be done in field. One thing to be considered if this method is used in field is that the verification method to confirm there is no leak. According to regulation, eternal barrier must be established. Therefore, the verification method should be established and monitoring of the well must also be done before confirming that this method is working.

Leaving production tubing and also control cable inside of the wellbore during P&A activity will cut most of the P&A operation itself. However, further verification and qualification need to be performed.

6.2.2. Control Lines Remover

As explained before, regulation mandates that any control lines outside the tubing to be removed to properly place a barrier material in the annulus. A new tool called MicroTubeRemover has been introduced by Aarbakke Innovation to cut a necessary length of the control lines and bring them to the surface. The tool will use wireline, thus, RLWI vessel unit can be used for this technology.

Figure 6-7 illustrates the operational sequences of the method. The brief steps are [39]:

a) The tool has a sensor to locate the collar of the control line. Then it will engage its anchors to hold the tool stationary while doing the next operation.
b) Sensor/milling module will locate the upper side of cable protector. After that, the milling tool penetrates tubing above clamp, mills down until contact with the clamp and then rotates while cutting the lines.

c) Tool releases both anchors and moves up to upper cable clamp. Next, the tool locates collar and again engages its anchors.
d) Afterward, the sensor/milling module rotates to locate microtubes and the upper side of cable protector. The mill penetrates the tubing (but do not extend far enough to damage/cut microtubes) and cuts away a window in the production/injection tubing so that it creates a hole.
e) The tool has a gripper device that extends from the tool to grip the lines and pull them in. After that, the mill is again extended, to a depth sufficient to cut the control lines and cut the lines.
f) The last step is to release the anchors and to pull out the tool out of the wellbore, with the necessary length of control lines held in place against the tool by the gripper.

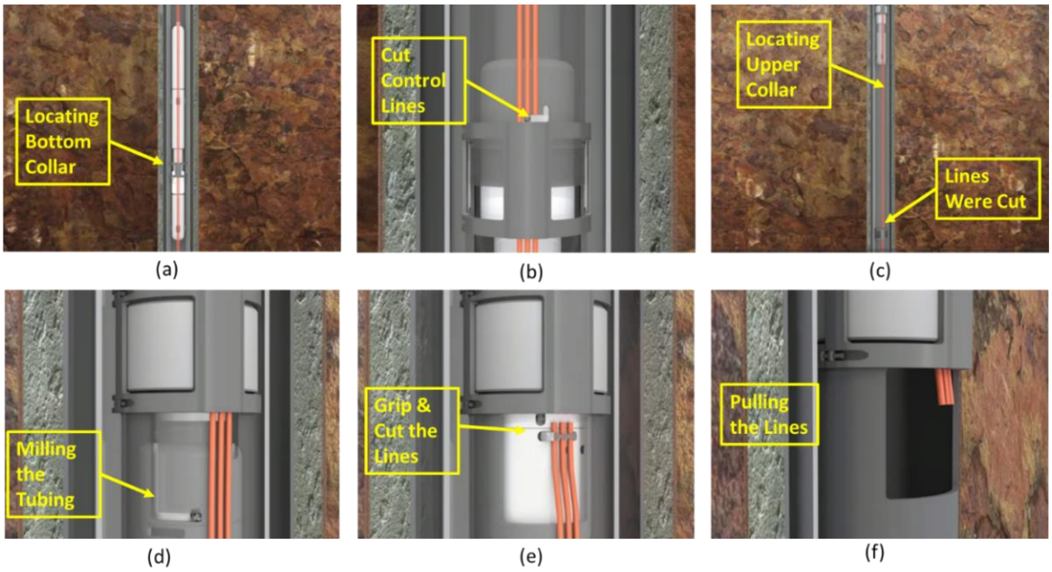


Figure 6-7 Operational Sequences of MicroTubeRemover [39]

<u>Comment</u>

The MicroTubeRemover looks promising. The tool allows leaving of production tubing permanently inside of the wellbore by cutting a necessary length of control lines. By leaving the tubing inside, rig is not needed to retrieve it. Moreover, the tools are run with wireline.

However, this tool is only a concept, thus, it is not field proven. An extensive number of qualifications are needed to be performed before test it on field. Furthermore, there are some disadvantages with this technology. A part of the tubing is cut to create a hole for pulling the control lines. This could reduce the tubing integrity.

6.2.3. Cutting of a Section of Tubing

Most of the current conventional P&A operation includes pulling of the production tubing to surface. As discussed before, one of the main reasons behind it is to remove the control lines on it to establish barrier. An equipment called Subsea Tubing Unit by GeoProber (Geo-STU), which can be utilized with RLWI vessel, is able to cut and recover a section of tubing, thus providing a window to establish a cement plug [40]. Figure 6-8 illustrates the equipment.

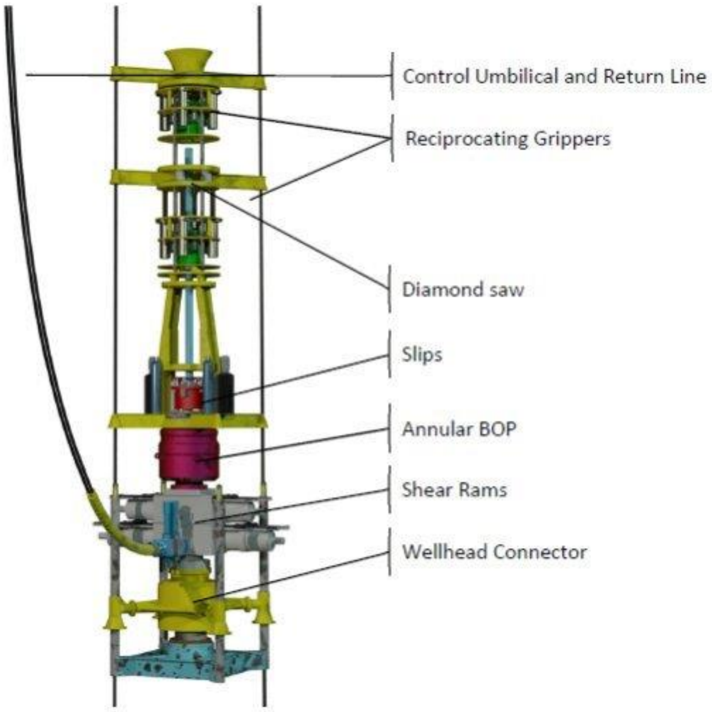


Figure 6-8 Subsea Tubing Unit by GeoProber [40]

The Geo-STU consists of two packages, a well control package and a reciprocating gripper package. As shown in the picture above, the well control package consists of shear rams, an annular preventer, and diamond saw. The reciprocating gripper package has two dual gripping units that are working as a jack system.

The tool is planned to be used from an RLWI vessel with the packages lowered to the subsea tree. To enable wireline operations, a wireline lubricator is run to the annular BOP and held by the grippers.

A tubing hanger revival tool mandrel is run in the upper grippers and then reciprocated into the tubing hanger. Once unlocked, the retrieval tool and tubing hanger and attached casing are reciprocated so that the tubing hanger is just below the upper package. The tubing is hung off below the hanger in specially designed orientating slips and cut enabling the retrieval of the tubing hanger [40].

Sections of tubing can then be reciprocated out of the well, cut using an inbuilt saw and then recovered to the vessel. The connection mandrel is re-run to allow the next section of tubing to be pulled. The procedure is repeated until the necessary length of window has been created for barrier establishment [40].

Comment

The Geo-STU is capable of cutting section by section of the production tubing, thus, providing a window for barrier establishment. This tool can cut some part of the tubing thus cement behind production casing can be logged. Moreover, to create a window for the reservoir and intermediate barrier establishment, the tool might be useful to cut some length of the tubing.

Unfortunately, further information regarding the unit is difficult to get during the writing of this thesis. Based on the author's assumption, the concept presently exists on paper only and would need to undergo comprehensive qualifications with a certain chance of failing due to the concept complexity. Furthermore, to create a space for the surface barrier, it needs to cut a long length of tubing (>2000 m).

6.2.4. Cutting and Compacting Tubing Method

There is a concept to avoid pulling of the tubing but cut and compact it instead. The equipment is wireline based, thus, riserless method can be applied using an RLWI vessel. The method is patented by Oilfield Innovation. The concept primarily concerns the removal of tubing. However, the technology can also be used to create a window to log behind casing. As shown in Figure 6-9, the concepts can be described with the same sequences as in the figure [41]:

a) Vertical cutting tool is lowered into the desired position and cut the tubing vertically. The tool is activated by a compression spring that exerts a constant force on the cutting wheels which are lifted up and down to cut the tubing vertically.
b) Push a whole tube within a split tube. The force necessary to splay split tubing is insignificant because the tubing has been vertically cut. Then inflatable packer piston is used to compact the tube by either a pump or the weight of fluid in the wellbore.
c) A space for cement placing is created. Optionally, it also provides space for cement bond logging of the cement between the casing.
d) When poor or no cement exists behind casing, it can be shredded to provide re-enforcement for a cement plug.

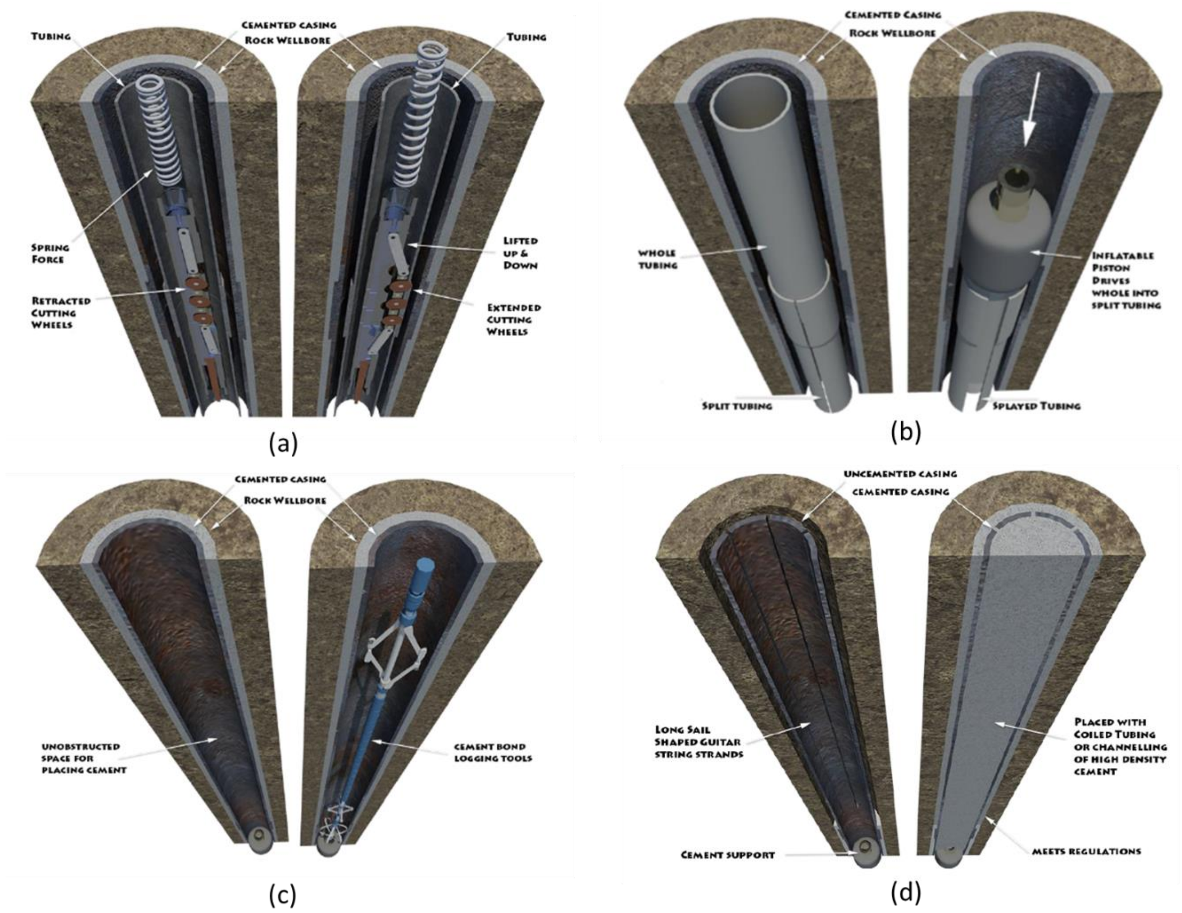


Figure 6-9 Tubing Cutting and Compacting Concept [41]

<u>Comment</u>

This concept could become a solution to leave the tubing in well during P&A operation. With this method, section milling is not needed. Moreover, an RLWI vessel can be used since the tool is wireline based. With compacting a section of the tube, space can be created to log cement behind casing without removing the whole tubing.

This method is still at a conceptual stage. A major challenge of this concept is that a significant force might be needed to compact the tubing downward.

6.2.5. Plasma-Based Tool for P&A

Another technology that is currently being developed is to use electrical plasma-based tool for casing milling. Using electrical arc, the tool can produce up to ten thousand of degrees Kelvin to melt the production tubing and casing [42].

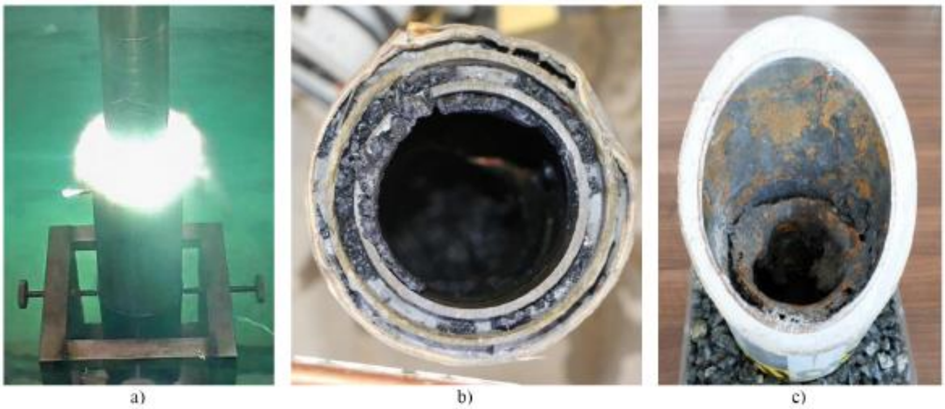


Figure 6-10 Plasma-Based Tool Entering Multistring Casing Sample (a); Upper View on The Sample After The Experiment (b); Sample After Diagonal Section in Order to Reveal Obtained Steel/Cement Removal (c) [42]

Figure 6-11 shows an example of cuttings after the milling process. Approximately, the maximum cutting size is 5 mm. The cuttings will be left inside of the wellbore during P&A process.

Figure 6-11 Cuttings from Plasma Milling Process [42]

The tool is designed to operate through tubing without the need for Xmas tree removal. This ability eliminates a need for tubing removal since the tool can mill tubing as well as casing in one trip. Figure 6-12 shows a process of tubing and casing milling using the plasma-based tool. The steps are summarized as follow:

a) The tool is inserted through the tubing
b) The electric arc is ignited, plasma is created and the tool is removing the tubing
c) The tool removes casing and cement layer
d) The tool is POOH
e) The section is ready for cement plug

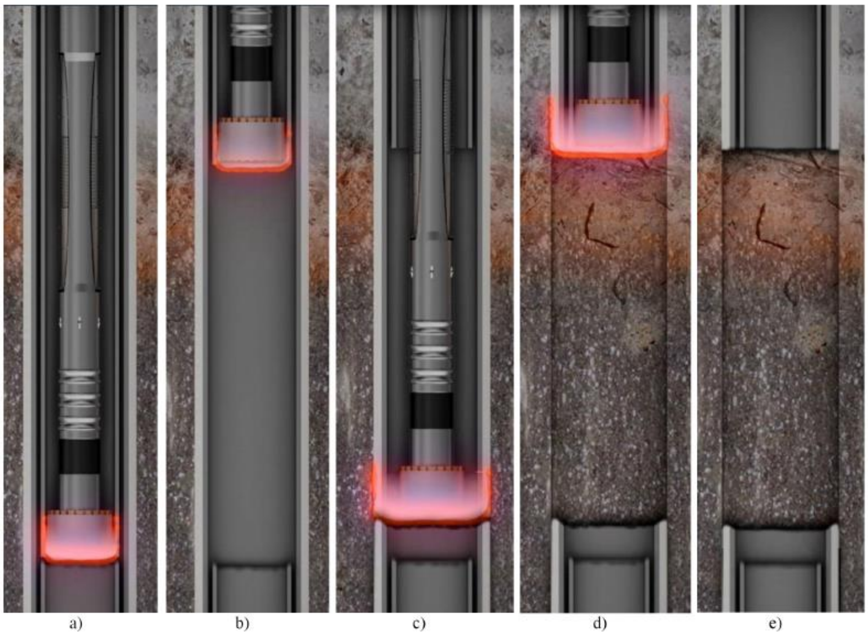


Figure 6-12 Casing Section Milling of Tubing and Casing with Plasma-Based Tool [42]

The P&A process of using this technology can be briefly summarized as follow [42]:

1. Rig-up on well and set plug below reservoir barrier depth. This plug will function as a sump for the melted material.
2. Run the tool inside, mill the required length through tubing, casing, and cement at reservoir barrier depth.
3. Set reservoir barrier (primary and secondary).
4. Set plug below the required depth for surface barrier. Again, this will function as a sump for the melted material.
5. Run the tool inside, mill the required length for surface barrier.
6. Set surface barrier.
7. Retrieve casing strings as per required depth below the seabed.

<u>Comment</u>

The tool is developed to simplify the process of P&A operation by eliminating the tubing removal and section milling operation. High temperature is created to melt the tubing and casings by producing electrical arc.

According to [42], the system is designed for coiled tubing operation. However, in the paper, it is stated that LWI vessel can be used for this technology. From the author's knowledge, current LWI vessel, that usually categorized within category A vessel, is not equipped for coiled tubing system. Therefore, probably category B (or category A with modifications) with workover riser need to be used to run the coiled tubing. However, if this tool can be run without a riser, it could reduce the operation time and cost.

Another advantage of this technology is that it has higher milling rate of penetration compare to the conventional section milling approach [42].

However, the P&A application of the plasma-based technology is currently under development. It is expected to be field tested in the North Sea by 2017 [42]. Furthermore, high power might be needed to create high energy to provide enough heat.

6.3. Reservoir Barrier Establishment and Circulation Path

As discussed before, reservoir barrier establishment is one of the challenges on P&A operation using RLWI vessel. The main reason is that it is difficult to have circulation path from the vessel to the wellbore that is needed during the cementing process. In this section, some concepts and technologies are described as proposed solutions for the challenge.

6.3.1. Establishing Unconventional Circulation Path

This section discusses several methods to establish circulation path from LWI vessel to the well.

6.3.1.1. Riserless Coiled Tubing Operation

While the use the vessel has reduced the need for rig, running of workover riser is still a time-consuming operation. More efficient way such a riserless system for doing well intervention is needed, especially for deep water. Riserless wireline systems have been used in oil & gas industry for a long time and proven to be used successfully. However, as mentioned in Chapter 2, coiled tubing has several benefits compare to wireline especially for P&A operation. Coiled tubing may be used to clean out the well before installing the plug, and for the barrier establishment.

Several studies have been done to identify the feasibility of doing a riserless coiled tubing operation. Within this section, the concepts of performing riserless coiled tubing operations from LWI vessels are discussed.

<u>Study of Riserless Coiled Tubing Operation</u>

In this section, an example of a study that had been done by ABB Offshore Systems [43] in the early 2000s is described. The objective of this study was to find a concept for subsea coiled tubing well intervention, without the use of a workover riser system.

Basically, the main features of the system are the use of a tensioned coil and a new lubrication system where the lubricator is placed above the coiled tubing injector as shown in Figure 6-13. The lubricator will reduce the bending moment on the Xmas tree adapter and the tensioned coiled tubing is used to monitor and predict the coil behavior during operation. The system has been designed for North Sea operation during the summer season in benign waters. The lubricator has 7-3/8" bore and is rated to 10,000 psi.

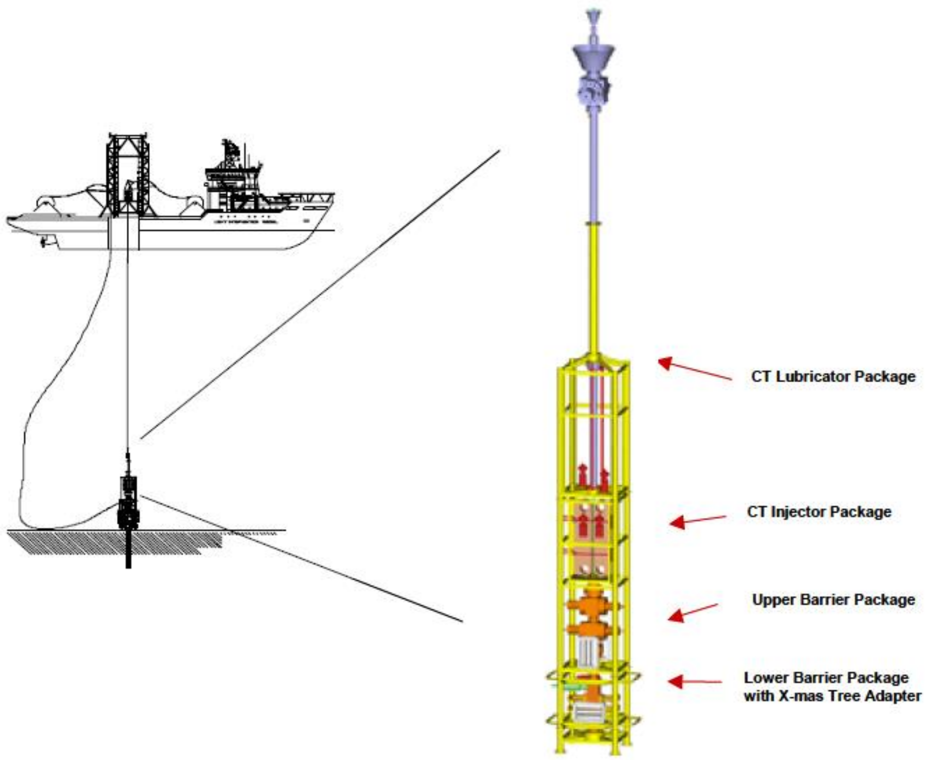


Figure 6-13 Riserless Coiled Tubing Well Intervention System [43]

One of the challenges of the riserless coiled tubing operation is the excessive bending deformations at the entry into the lubricator system and at the top where the coil leaves the vessel. The deformations must be restricted. Furthermore, without the workover riser, the coil will experience the same external loads as a riser. Besides the loads from the internal fluid and toolstring themselves, they will have load by vessel motion, waves, and also the current. To solve this issue, they will have bend restrictor devices at the top of the lubricator and the vessel connection. A tensioned coil configuration and a heave compensation system are also required to ensure coil integrity. Furthermore, a coil monitoring system including position and tension measurement subsea is required in addition the normal wear monitoring [43].

Within this concept, they have the typical surface system as the standard coiled tubing equipment such as reel and power packs, in addition to the equipment required to maintain a tensioned coil configuration. Besides that, this concept also includes a derrick to handle the subsea equipment and toolstrings, as shown in Figure 6-14.

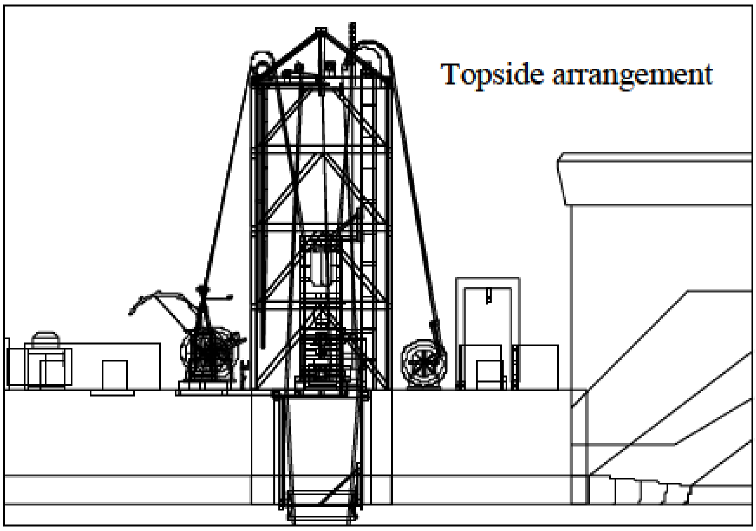


Figure 6-14 Topside Arrangement Before Start of Operation [43]

Another thing to be considered is the WBE during operation. The subsea lubricator system consists of the coiled tubing lubricator package, the coiled tubing injector package, and the well barrier package. The deployment sequence of the system is illustrated in Figure 6-15. The top section of the lubricator contains a fixed stripper element, a movable stripper element, and a shear seal BOP that can cut the coiled tubing above the injector in case of a drift-off situation [43].

In addition to the riserless coiled tubing system itself, this operation also need a vessel that have certain requirements [43], such as:

- Sufficient deck space for the equipment
- Vessel characteristics must be satisfactory regarding heave, roll and pitch for operations in North Sea (13 ft significant wave height)
- DP 3 system
- The vessel must have heave compensation system.
- The vessel must be equipped with sufficient pumping facilities.
- Moonpool or deployment area bigger than 16 ft x 20 ft. A derrick arrangement above the moonpool is required.
- Deck crane capacity should be minimum of 66,000 lbs for loading and unloading equipment.

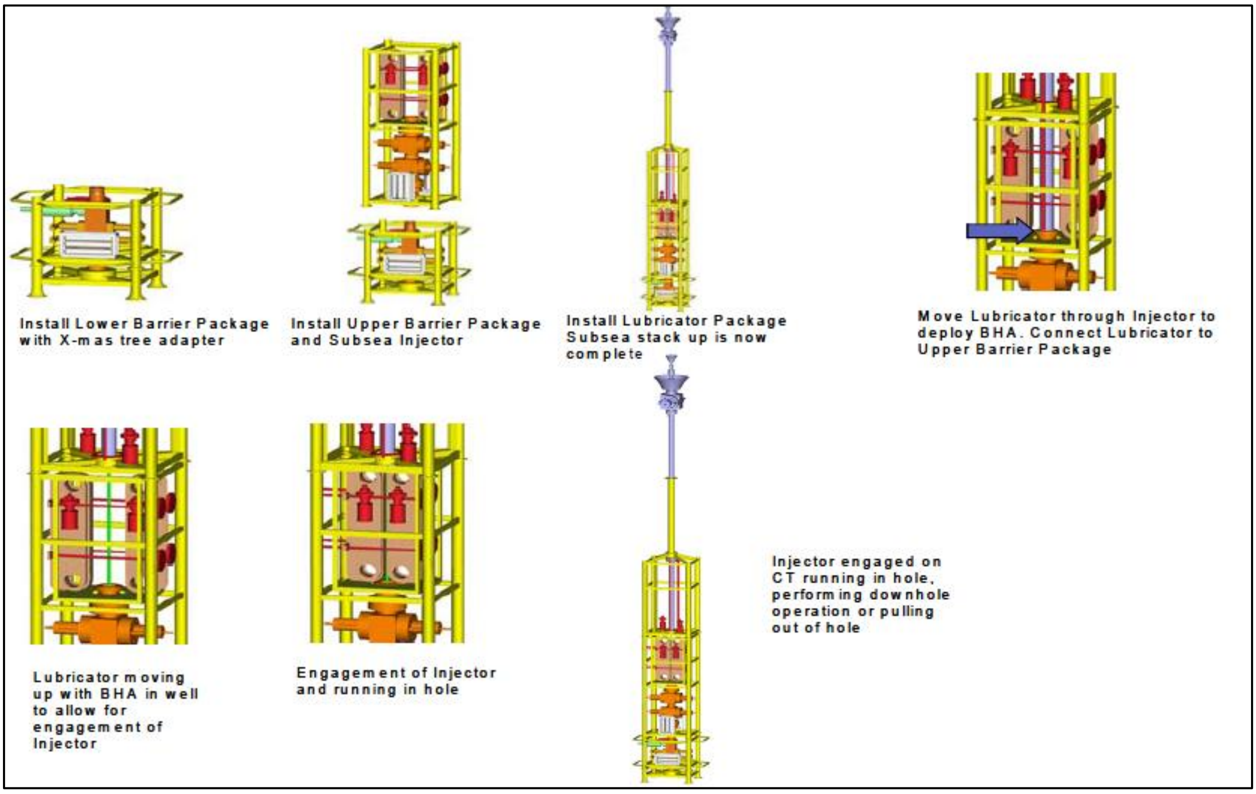


Figure 6-15 Deployment Sequence [43]

Island Offshore Open Water Coiled Tubing Top Hole Drilling

Island Offshore had executed two drilling operations with riserless coiled tubing system. However, both operations are executed in non-pressure applications. The first one is "RogFast" 25 km tunnel drilling project and the other one is pilot hole drilling to determine the presence of shallow gas prior to commencing drilling operations with a semi-sub drilling unit. Both projects were done using LWI vessel. In this section, the overview of the technology is described.

Figure 6-16 and Figure 6-17 illustrate the project specific equipment. There are two injectors installed in the system, on the vessel and on top the subsea lubricator. This enables sufficient force for the drilling operation. The surface injector is installed in the vessel intervention tower from where the coiled tubing string passes through the vessel's moonpool to the seabed, reaching the subsea injector which is installed on a guide base, enabling it to be securely anchored.

The are several modifications on the vessel for this project. An intervention tower was installed over the moonpool. An **injector parking stand** supports the subsea coiled tubing injector during the surface rig up phase. The lower cursor frame was modified to support the surface coiled tubing injector which enables the vertical forces generated by the surface injector to transfer to the passive heave compensator. Any lateral force generated by vessel movement is transferred to the tower guide rails. The tower also includes a platform frame for safe access to the injectors during maintenance periods in the operation. A **passive heave compensato**r was installed between the lower cursor frame and the main winch hook in the intervention tower. This provides vertical heave compensation to the surface injector during the operation. In addition, the compensator and the surface injector maintain a positive tension in the coiled tubing during drilling operations. A **Funnel** was mounted below the surface injector to guide and limit bending of the coiled tubing string during subsea injector deployment and retrieval operations. A standard coiled tubing reel was used to keep the coiled tubing string between the reel and the surface injector in tension. A subsea wiper, comprising of a steel housing with rubber seals and brass bushings was also necessary to prevent gravel and mud from drilling operations entering the subsea injector. A subsea connector was used to latch and unlatch the subsea injector the subsea guide base, which comprises a steel frame with a 15 m lubricator section. The main purpose of this guide base is to level the lubricator section by using the four hydraulic operated legs and to give the subsea injector a stable foundation [44].

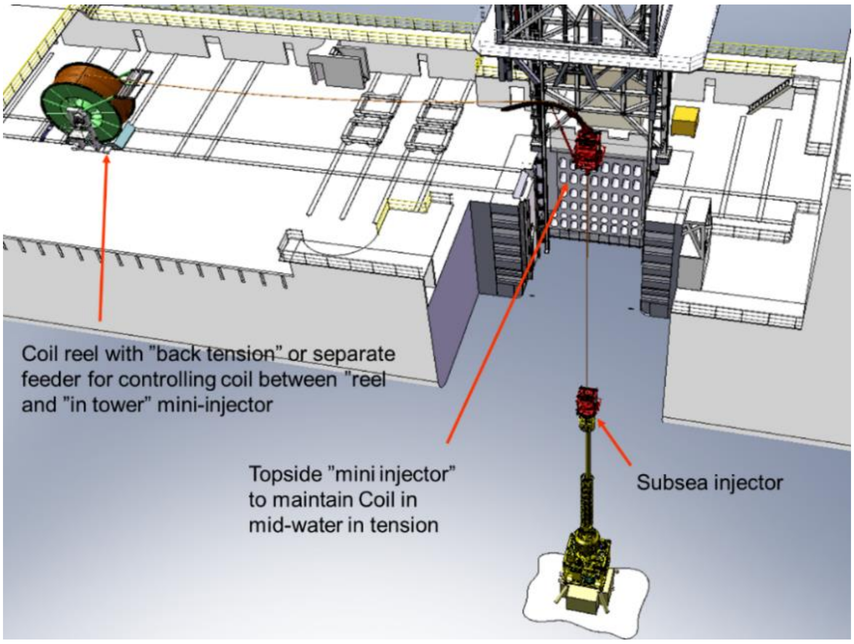


Figure 6-16 Equipment Layout [45]

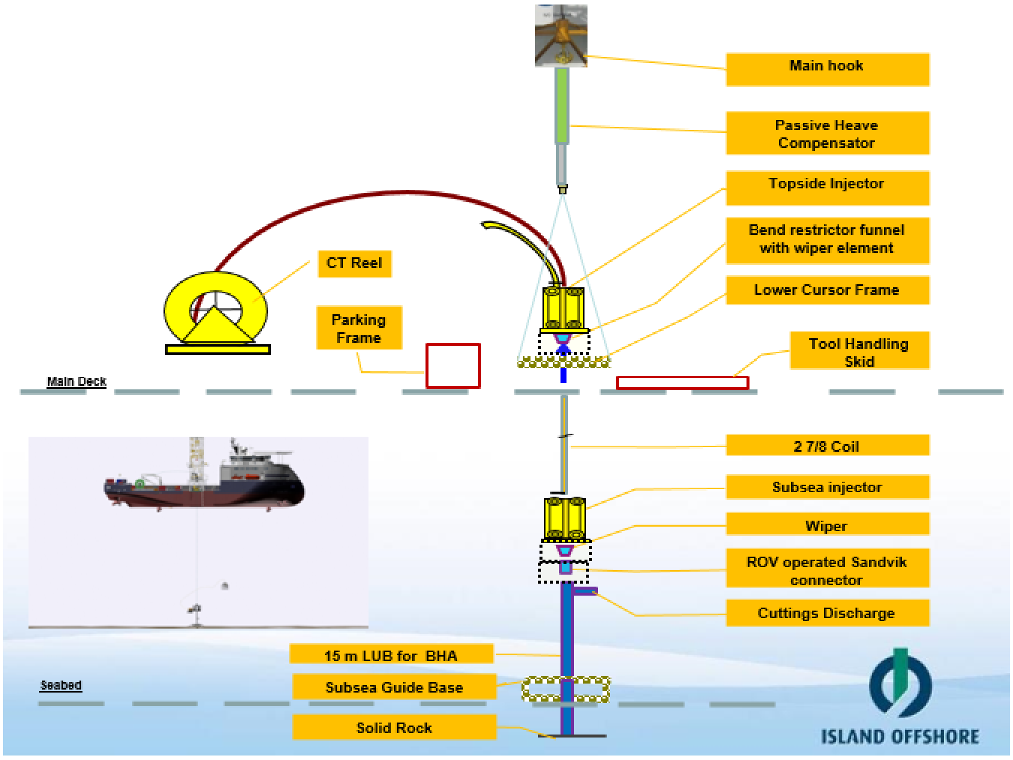


Figure 6-17 Equipment Stack-up [44]

Comment

Riserless coiled tubing operation has been successfully run using two injectors installed in the system. With some modifications in the vessel, the project marks the first steps toward live well intervention using coiled tubing running from LWI vessel.

Basically, most of the P&A steps can be done using coiled tubing. A coiled tubing operation allows for circulation. Rotation is also possible with motor applied. Coiled tubing is stronger than wireline, thus allowing heavier operations to be performed. However, there are several challenges that need to be solved to apply the technology in P&A operation. As discussed, there are several requirements for the vessel, such as sufficient deck space, pumping facilities, and heave compensation system.

Another challenge is riserless coiled tubing operations introduce an additional factor that reduces the coiled tubing fatigue life. Because being exposed directly to seawater, tension needs to be maintained between surface and seabed as the coil will experience the same external loads as a riser. Moreover, corrosion may become one of the issues because the long-term exposure to seawater.

To run in a live well for P&A operation, safety requirement must also be considered. Relative motion between the coil and the vessel, also the interface between high pressure in the well and relatively low ambient pressure on the seabed environment will create technical challenges to establish well barrier during operation.

Another problem that may occur is the handling of fluid return with a barrier in place. One of the options is to use fluids that are environmentally safe, thus, the fluid pumped through coiled tubing may rise up the wellbore and discharge into the sea.

In the Island Offshore project, the operation was a top hole drilling, in which the risk is lower than intervention in a live well. Further development of the system should be done to use the technology in a live well so that it can be used for P&A operation. However, if this technology is fully developed for a live well, the PWC or plasma tool can be deployed with the system, providing more options for subsea P&A operation.

6.3.1.2. Riser Based Coiled Tubing Operation using LWI Vessel

In the previous section, the system for riserless coiled tubing using LWI vessel was discussed. The question is, why don't we use a riser for coiled tubing operation using LWI vessel?

Coiled tubing operations on a subsea well had been successfully executed for the first time at the end of 1997. Using CSO Seawell vessel, the intervention was done on the Gannet field for Shell in the North Sea. The coiled tubing was run through the workover riser system as shown in Figure 6-18. The operation was executed on the live Gannet well, and production logging test was conducted using coiled tubing [46]. This project shows that the system of the riser based coil tubing operation using LWI vessel was already developed some 20 years ago.

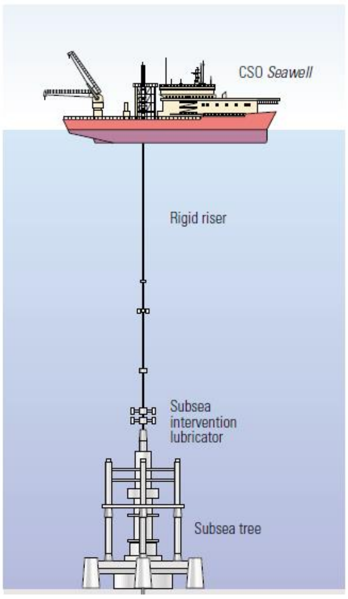


Figure 6-18 Coiled Tubing Operations on Vessel [46]

In the next sections, there are two studies to use a riser for coiled tubing operation in an LWI vessel that are discussed. Both studies were done to study the feasibility of well intervention operation in deep and ultra-deep waters.

Light Well Intervention Riser System (LWIRS) [47]

Figure 6-19 illustrates the proposed concept of the LWIRS study by Aker Oilfield Services in 2010. This system consists of 5 sections; Low-pressure slip joint, submerged flow and safety head, lubricator valves, high-pressure riser, and lower riser package [47].

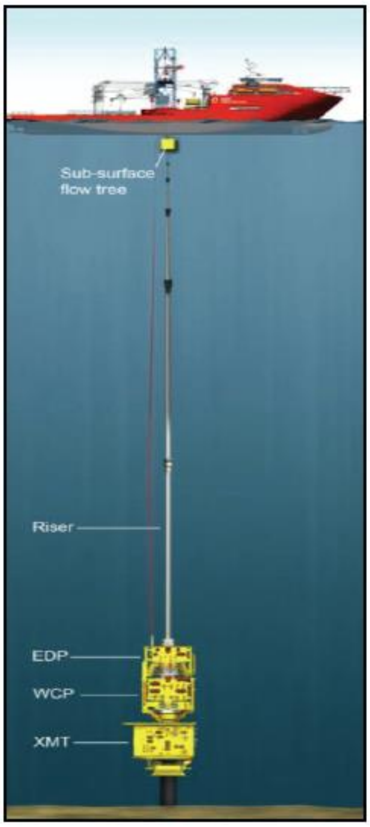


Figure 6-19 Light Well Intervention Riser System [47]

As shown in the picture, EDP sits on top of Well Control Package (WCP). The package is called **Lower Riser Package**. The WCP consists of conventional equipment as found on RLWI solutions today, as discussed in chapter 2.2.4. It has the ability to close the well against fluid pressures. The EDP allows safe disconnection during operation when needed.

The **high-pressure riser** is a standard riser assembly (~7”). The riser is handled by standard riser handling equipment as found on modern drilling rigs.

The **lubricator valves** are located approximately 80 meters below the vessel. The function is to seal and hold pressure. These valves function as one of the two main barriers; the other barrier being the retainer valve in the lower riser package.

The **Submerged Flow and Safety Head** (SFSH) is the point where the riser changes from high pressure to low pressure. It consists of two cutting rams which can cut up to a 2-7/8" coiled tubing. For coiled tubing operation, there is stab-in latch, allowing high-pressure risers to be run all the way back to the coiled tubing pressure control found in the derrick.

Above the SFSH, the low-pressure riser section and the **low-pressure slip joint** are located. The section is hung off on the work floor, allowing for all well intervention operations to rig-up in a non-heaving environment.

Beside the main equipment above, the vessel also needs to be equipped with coiled tubing tension frame. The main purpose of the frame is to secure a heave, roll and pitch compensated support for the pressure control equipment utilized during the coiled tubing operations.

Self Standing Riser [48]

Another concept of deploying riser using LWI vessel has been proposed by Nautilus International in 2010. The technology uses a riser called Self Standing Riser (SSR), where it attaches to the subsea tree and provide the support and a circulation conduit for coiled tubing to have full circulation capabilities back to the intervention vessel. SSR is a system of pipe supported by some type of buoyancy device [48]. Figure 6-20 illustrates the basic SSR system and the proposed system for coiled tubing operation.

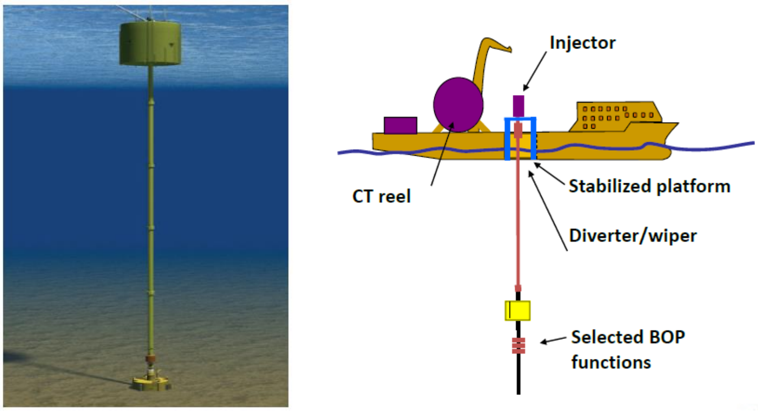


Figure 6-20 Basic SSR (left); Proposed SSR Coiled Tubing System (right) [48]

The SSR is connected to the tree with a standardized subsea connector. Adjustable buoyancy devices are attached to the riser pipe to support and tension the riser pipe. At some depth, the top buoyancy device will support a secondary BOP system with shear rams that are able to cut the coiled tubing inside of the riser.

The entire SSR can be installed prior to the intervention operation by another vessel. Once the SSR is installed with the proper safety equipment, the SSR can remain in a stand-by mode until the intervention vessel arrives.

To connect the vessel with the SSR, a short section of riser is run from the vessel and connected to the top connector of the SSR. Once the connection is made, the operation to kill the well can be achieved. After the well is killed, the coiled tubing operation can commence through the SSR. With the short riser connection from the vessel to the SSR, a heave compensation system is installed in the vessel.

Comment

As mentioned before, coiled tubing can execute most of the operations in P&A activity. With the new technology, such is provided by PWC or plasma-based tool, coiled tubing operation will become more attractive for P&A operation in subsea wells.

The riser based coiled tubing system seems promising to be applied in P&A operation. However, there are some challenges to overcome. Some modifications of the LWI vessel must be done in order to satisfy the operational requirements. The derrick system on the vessel must have the capability to lift the riser system. Heave compensator equipment must also be installed to overcome the heave motion when in operation. Furthermore, the mezzanine deck might need to be installed to provide coiled tubing equipment and the risers. Additionally, fluid handling equipment should be available.

However, the method has been successfully executed using CSO Seawell, that is an 'old' vessel, in 1997, which is some 20 years ago. Although it was not for P&A operation, with the current vessel technology, and several new P&A technologies, the riser based P&A method using LWI vessel could become one of the best options.

The SSR technology offers the better system with respect to the need of vessel modifications. With the ability to be installed prior the intervention works, the riser can be installed using another vessel. However, it will increase the cost. There is another disadvantage of the system. The SSR system must accommodate the connection of the SSR for both the vertical and horizontal subsea trees.

Another thing to be considered is the size and weight of the coiled tubing equipment and the reel. A coil of 25,000 ft – 40,000 ft (7,600 m – 12,200 m) of 2-3/8" steel pipe is massive and not easily mounted on deck.

6.3.1.3. Reelwell Drilling Method (RDM)

Reelwell has developed a drilling method based on concentric drill string called dual drill string (DDS) The DDS consists of outer and inner pipe as a closed loop drilling system. The drilling fluid returns up to the surface through the inner pipe thus, marine riser is not needed. Figure 6-21 shows the difference between conventional drilling and reelwell drilling method. As shown in the picture, drilling fluid is pumped into the well down through the drill string and return through 21” marine riser in conventional drilling. While in RDM technology, drilling fluid is pumped down through the DDS outer pipe and returns up through the DDS inner pipe.

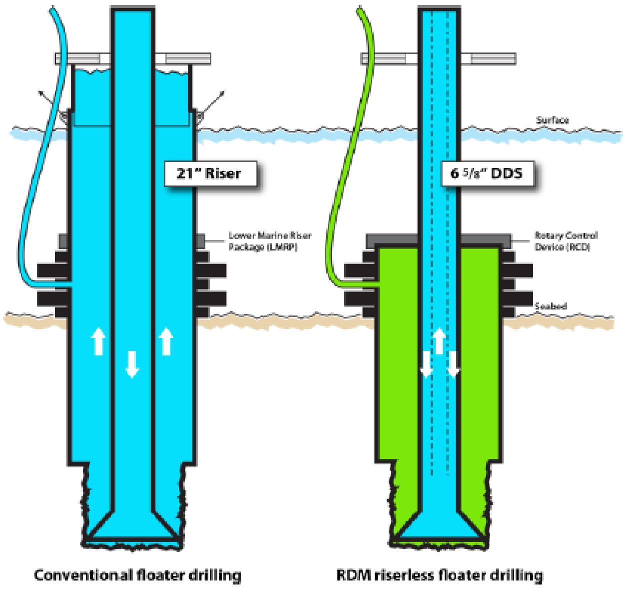


Figure 6-21 Conventional Drilling vs RDM [49]

There are a lot of subsea wells that are currently being temporary plugged. According to Spieler & Øia in their presentation in Norwegian Plug & Abandon Seminar 2015 [1], there are 71 subsea wells that are temporarily abandoned in NCS. There are more of those temporarily abandoned subsea wells in the other part of the world. Eventually, those wells need to be permanently plugged in a cost-effective way.

Some of the wells that are temporarily plugged have shallow cement barrier as illustrated in Figure 6-22. In order to convert them into a permanent plugged well, the shallow barrier needs to be drilled and thereafter continue with the establishment of permanent barriers that covers the entire cross section of the wellbore. To be able to drill the barrier, currently, the conventional way is to drill it with a rig with the installation of 21” marine riser as described in section 2.2.3. For deep water area like in the Gulf of Mexico, the installation of the marine riser could take days of operation, thus, it will not be a cost-effective operation. Presently, the RDM technology could become one of the most cost-effective ways to drill the temporary cement barrier (as shown in Figure 6-22), and then convert it into a permanent abandoned well.

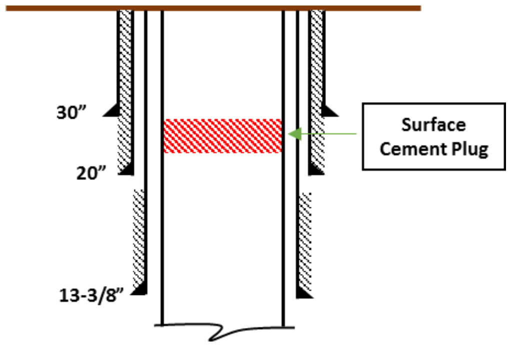


Figure 6-22 Example of Typical Temporary Abandoned Well

Comment

RDM technology has several advantages for this special case of P&A operation. It is a partly proven technology through a number of full-scale tests. Without drilling riser needed, the cost can be reduced significantly due to the less operation time. Another advantage is enclosed circulation system thus barrier plug can also be established inside. Less fluid volume is also needed because the fluid is run through the smaller inner pipe rather than circulated through a 21” marine riser.

However, a rig is needed to do the operation. Although it may be possible to do the operation using LWI vessel, a significant modification is needed, such as to provide drilling system, with derrick, top-drive, pipe handling, and pipe rotation unit. Currently, utilizing RDM technology by rig is one of the best solutions available for this special case, unless the riser/riserless coiled tubing system on LWI vessel is fully developed.

6.3.2. Thermite P&A Solution

Interwell is inventing a new technology for P&A operation to establish barriers required for P&A activity using a wireline based tool. The technology is capable of establishing reservoir, intermediate, and surface barriers. Basically, the method is to melt the surrounding materials inside the wellbore (casings, tubing, cement, formation, etc.) by providing enough heat. Those melting materials then become the barrier itself.

The heat is generated by igniting thermite component. Thermite is a pyrotechnic composition of metal powder fuel and metal oxide. When ignited by heat, thermite undergoes an exothermic reduction-oxidation (redox) reaction [50].

To understand the chemical reaction behind this, an example of the reaction is shown in the following line:

$Fe_2O_3 + 2\ Al \rightarrow 2\ Fe + Al_2O_3$

The aluminum reduces the oxide of another metal, here is iron oxide. The products are aluminum oxide, iron, and a large amount of heat. The reactants are commonly powdered and mixed with a binder to keep the material solid and prevent separation [50]. This heat can provide extremely high temperatures focused on a very small volume for a short period of time. The temperatures may reach as high as 3000°C.

Figure 6-23 shows the P&A operational sequences using this technology. Before lowering the tools into the wellbore, the required amount of a heat generating mixture (thermite) is provided. After that the P&A operation is started. In a simple way, the basic steps are (as illustrated in the figure):

a) positioning the tool at a desired position inside the tubing,
b) igniting the thermite,
c) the heat is melting the surrounding materials in the well,
d) restoring the cap-rock as the barrier of the wellbore.

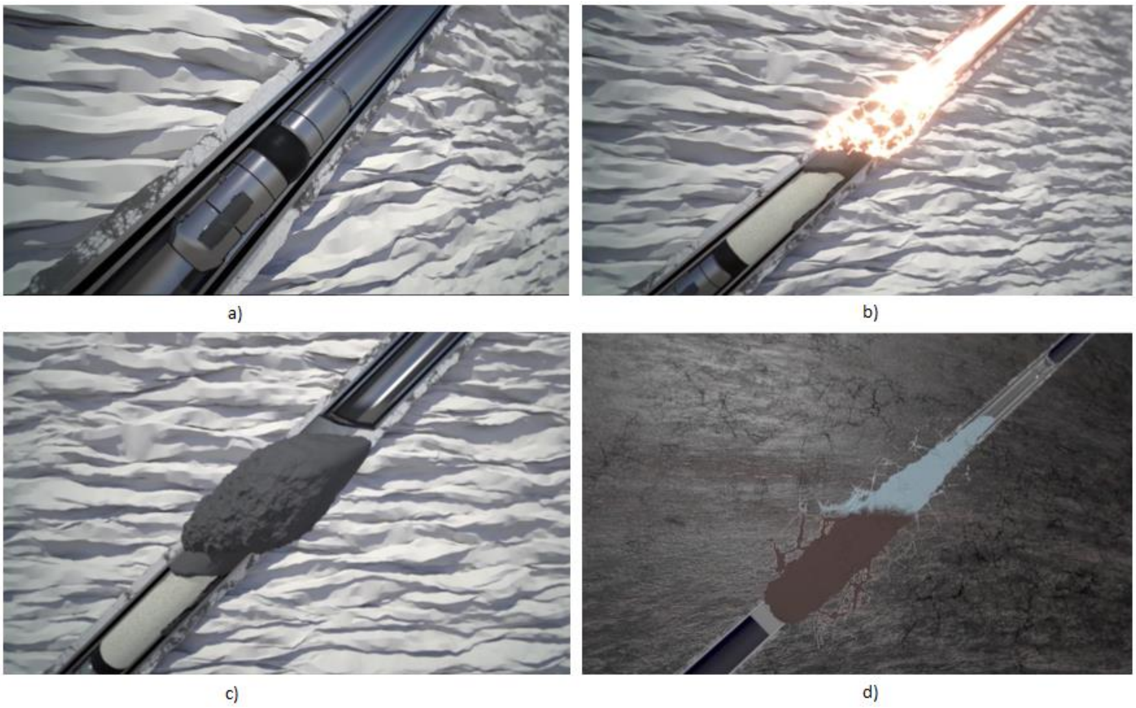


Figure 6-23 Operational Sequences of Interwell P&A [51]

Comment

The thermite solution that is introduced by Interwell could become a 'game changer' for the whole P&A operation. Pulling tubing is not needed, nor section milling and cementing. Thus, it will cut a significant P&A operation time. With exothermic reaction using thermite, the barrier could be created by the materials inside of the wellbore by melting them.

Moreover, the tools can be run on wireline, thus RLWI vessel can be used for this method. This is one of the major advantages of using this technology.

However, since this is a new technology and not field tested, one should ask some questions regarding this technology:

- How strong is the bond between the plug and the formation?
- Will there be any crack inside to allow vertical leak path?
- How to put the correct amount of thermite to get the minimum length of barrier?

Nevertheless, this is an 'out of the box' idea of performing P&A operation. After several successful field tests, this method could become a real solution for a cost-effective way of performing P&A operation using RLWI vessel.

6.3.3. PWC Technology

A perforate, wash, and cement (PWC) system was introduced by a company called HydraWell Intervention in 2008. This system was developed to eliminate the problems associated with conventional section milling operations. However, it is important to note that the production tubing needs to be cut and pulled before using this technology. The operational sequences basically consist of three phases, as self-explained in the system itself, perforation of the casing, wash the annulus, then cementing in one run. The system can be used to establish reservoir barrier, intermediate barrier, and surface barrier. Thus, a circulation path is needed from the vessel to the well to use this technology. The operation is generally executed by drillpipe. However, HydraWell has also proposed to run the tool on coiled tubing [52]. This technology has never been executed using LWI vessel. However, if circulation path is established, using the methods that are described in chapter 6.3.1, it is probably possible to use this technology with LWI vessel.

The most beneficial thing about this system is that it eliminates section milling. As mentioned earlier in this thesis, section milling is one of the greatest challenges of P&A operation. Thus, with this technology, no swarf and metal associated with milling will be generated from the operation. It will provide a safer working environment and also reduces the need for additional surface handling equipment due to milling debris. Moreover, several jobs performed with this system shows that an average time of 7.9 days per set plug is saved compare to the conventional section milling [53]. HydraWell offers two methods of plugging operations; single annulus plugging and multi annulus plugging operations.

6.3.3.1. Single Annulus Tools and Operation

When a single casing needs to be plugged, the configuration of tools shown in Figure 6-24 is used. The system consists of an assembly containing a tubing-conveyed perforating (TCP) gun, the HydraWash jetting tool, a cement stinger, and the HydraArchimedes cementing tool.

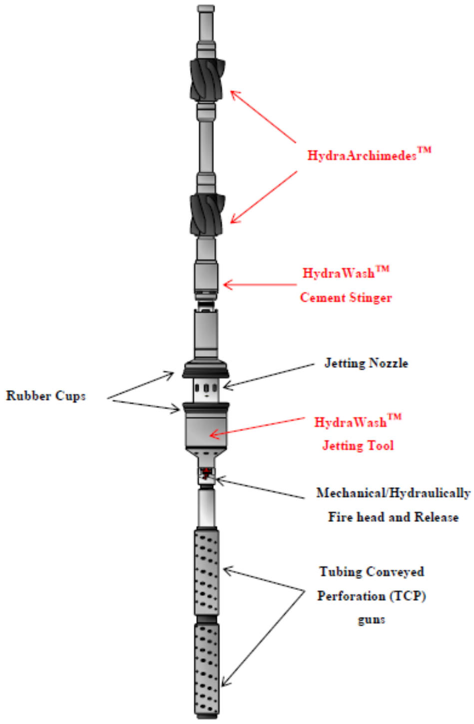


Figure 6-24 HydraWell System Tools for Single Annulus Operation [54]

<u>The Tools</u>

HydraWash

The HydraWash Jetting Tool is used to wash and clean out debris, old mud, and cement traces in the annulus behind a perforated casing. After the washing is done, a deactivation ball is dropped to disconnect the HydraWash Jetting Tool. The lower part is dropped and the remaining tool is converted into a HydraWash Cement Stinger. This tool enables placing plugging material in the well's entire cross section [52].

HydraArchimedes

The HydraArchimedes tool is used to force the cement through the perforations and to fill the annulus. The tool is rotated while the cementing process is done to squeeze the cement into the annulus. The tool is needed because the casing is still in place so that it can be difficult to establish a good barrier inside the annulus by just pumping down cement [52].

The Operation

To illustrate (Figure 6-25) how this system works, a typical operational sequence will be described for the one trip system [52]:

a) Lowering the tools into the desired position. Shoot the TCP gun. After the perforation has been done, the perforating assembly is then automatically dropped and left in the well.
b) After the gun is dropped, a ball is dropped to the HydraWash tool and initiate the washing process. The flow is directed through the perforation. The annular space between the formation and casing is cleaned. Debris, old mud, old cutting, etc. are replaced by clean mud.
c) Once the annular space has been thoroughly cleaned, a spacer fluid is pumped into the area. A second ball is dropped, disconnect the HydraWash tool, and convert it to a cement stinger. The HydraWash is left below the perforations, and act as a base to the cement plug. Cement is pumped through the cement stinger and fills the area.
d) The HydraArchimedes tool rotates to force the cement through the perforation, thus ensuring a uniform plug.

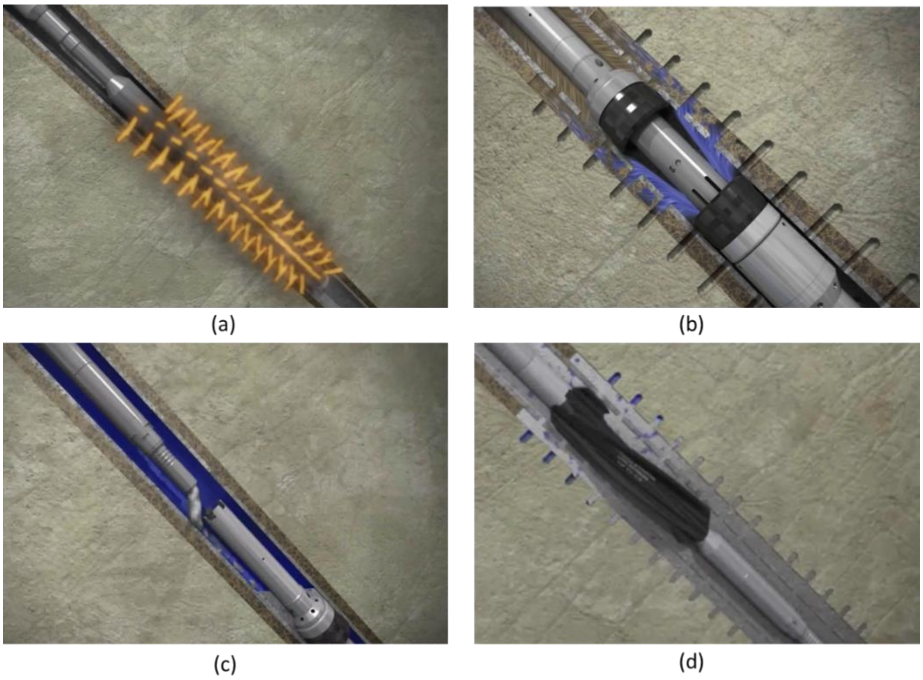


Figure 6-25 Single Casing HydraWash P&A Operation [52]

6.3.3.2. Multiple Annuli Tools & Operation

HydraWell has also developed a system to apply the PWC concept for multiple annuli. Basically, the procedure is more or less the same with the single annulus operation that has previously described. However, the system has different tools; HydraHemera is used instead of HydraWash. HydraHemera provides better jetting and spray tools to penetrate multiple annuli. The other tool that might be used is called HydraKratos. The HydraKratos tool is *only* run if there is a need for a foundation of cement plug to be placed in the annulus. Figure 6-26 illustrates the configuration of tools for multiple annuli operations (without HydraKratos).

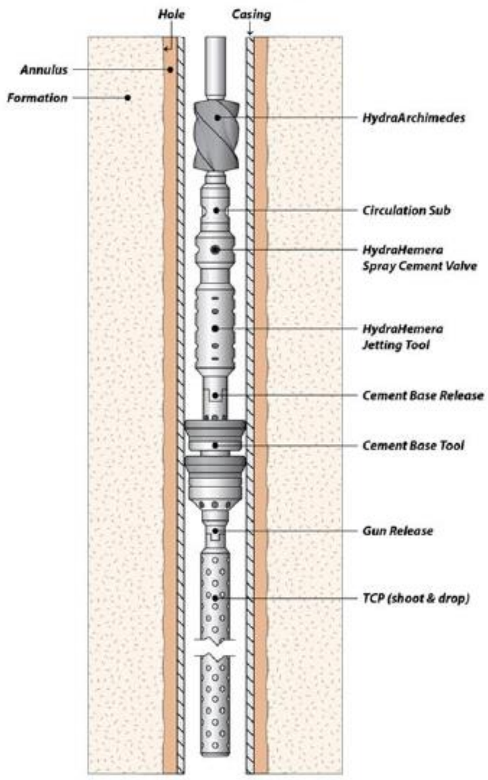


Figure 6-26 HydraWell Tools Configuration for Multi Annulus Operation [55]

<u>The Tools</u>

HydraHemera

The HydraHemera system consists of two units; a HydraHemera Jetting Tool and a HydraHemera Cementing Tool. The HydraHemera Jetting Tool features jet nozzles which are positioned at irregular angles that can penetrate and clean thoroughly behind multiple perforated casings [52]. It is important to note that the HydraHemera system can also be used to wash behind a single casing.

HydraKratos

HydraKratos is used to make a solid base for the annulus. The HydraKratos system consists of the HydraKratos casing expander and TCP gun. The TCP is positioned inside of the well above the HydraKratos tool. Figure 6-27 illustrates the operation method of this system. A ball is dropped to initiate the gun, then it perforates the casings. The energy from the explosion of the HydraKratos expands both casings ensuring a casing to formation wall fit. This provides a base for the cement to plug in the inner and outer annulus. Next step is to pull the drillstring out of hole, and the P&A operation will be continued with HydraHemera system [52].

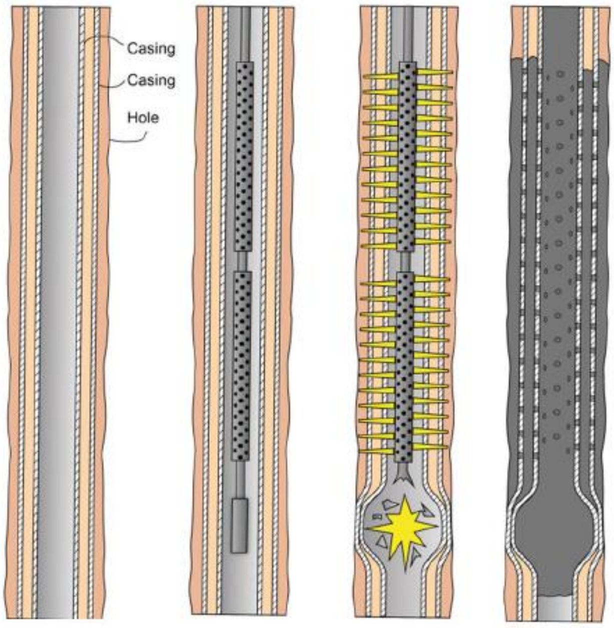


Figure 6-27 HydraKratos Tool [55]

<u>The Operations</u>

The washing process begins after the HydraHemera run inside the well. A ball is dropped to initiate the washing process. The flow is then directed through nozzles creating a high energy of jets that enables to penetrate the casings as illustrated in Figure 6-28. The annulus behind the casings is then cleaned from debris, old mud, etc. and replace by clean mud. The nozzles on the jetting tool are engineered to make it possible to clean all voids in the multiple casings. The washing operation is done twice to ensure proper cleaning.

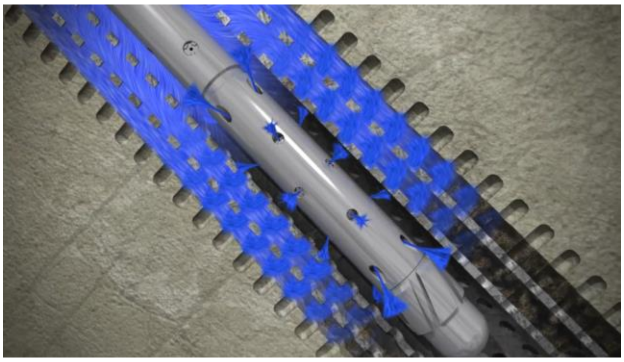


Figure 6-28 HydraHemera Washing Operation [52]

After the annuli are cleaned, a second ball is dropped and divert the flow to the cementing tool. Then cement is injected through the perforation and fills the area. The HydraArchimedes tool rotates to force the cement through the perforation as described before in HydraWash system [52].

6.3.3.3. Coiled Tubing Operation

Another information about this system is that a rigless coiled-tubing HydraHemera P&A system has been developed and successfully applied in the North Slope, Alaska [52]. Using 2 3/8" coiled tubing, a permanent P&A plug has been installed in 7" liner. The tool is illustrated in Figure 6-29.

Figure 6-29 HydraHemera Coiled Tubing System [55]

This operation shows the possibility to execute the PWC operation using coiled tubing system.

Comment

PWC technology by Hydrawell is one of the most popular P&A technology in the industry. It is a proven technology since it has been used to plug several wells in the NCS. One of the main advantages of this technology is the elimination of section milling because the casing is perforated. It means that no swarf will be generated in the operation. Swarfs are unwanted materials which have a lot of disadvantages that has been described before. Without section milling, the casing remains intact, thus, re-entry is possible at a later time if needed. Furthermore, the technology is capable of establishing barrier through multiple casings. Therefore, the challenge of establishing barriers in B and C annulus can also be solved with this tool.

The main issue of the PWC method is that the tubing needs to be cut and pulled. Moreover, there are several issues regarding plug verification. With PWC technology, there will be cement inside the annulus. This means that bonding of cement and casing need to be logged. For one annulus PWC operation, logging is possible to be done by drilling the cement plug inside the string so that logging equipment can log the annulus. However, for multiple annuli cementing, as mentioned before there is currently no technology to log through several casings. Thus, sometimes section milling still has to be done. Therefore, although PWC is recognized to be the primary option for barrier establishment, the current technology is still not ready to fully replace section milling.

6.4. B & C Annulus Barrier Establishment

There are several technologies that have been developed to establish intermediate barrier using an RLWI vessel. In this section, two technologies that have been used for P&A operation for several wells, WASP and SWAT are briefly discussed. Basically, both of the tools have the same function; to perforate and cement multiple. However, it is important to note that one of the main requirement for these tools is the establishment of reservoir barrier (primary and secondary barrier). Furthermore, the tubing should be retrieved.

6.4.1. Well Abandonment Straddle Packer (WASP)

WASP is a tool that was developed by Baker Hughes. The system is designed to be deployed from an RLWI vessel. The system consists of two inflatable packers for isolations and two pairs of selective perforation guns. The schematic operation is shown in Figure 6-30.

The process starts with establishing sealing off the wellbore and perforation of the B annulus. The perforation is done below the bottom packer and also between the packers. These two perforations create circulation path that is used to install cement barrier. The second annulus is then perforated through the existing barrier to create communication to the next annulus. The last step is to establish barrier into the C annulus.

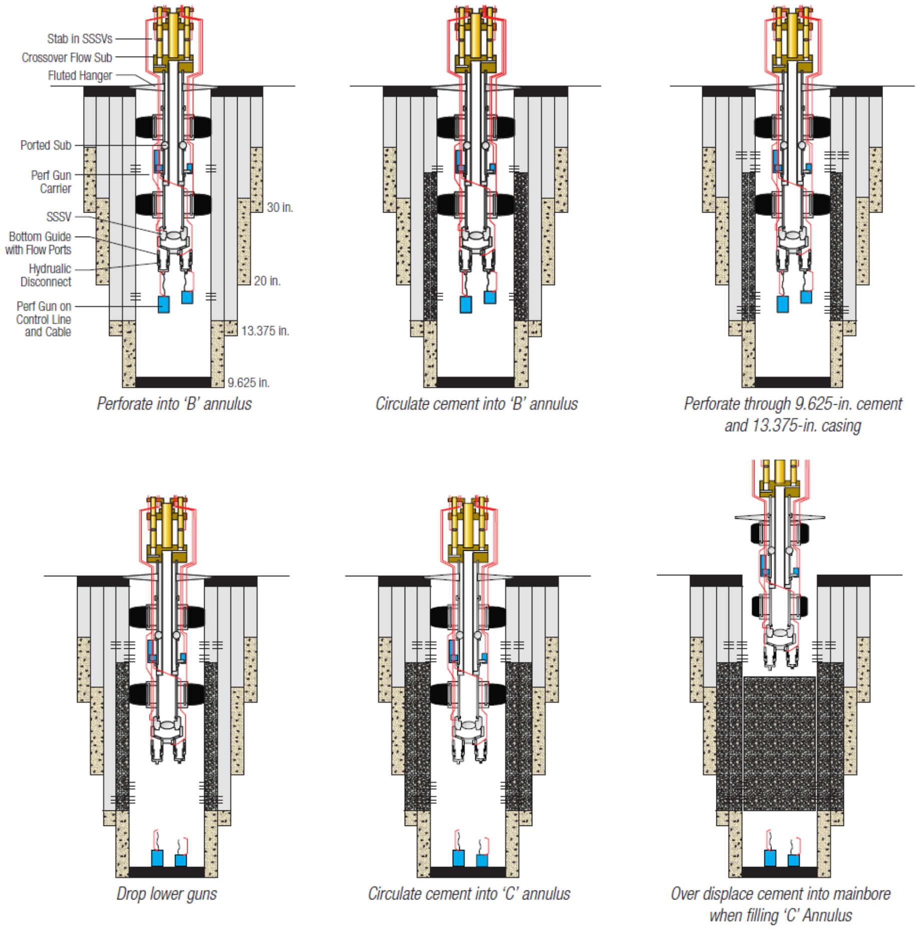


Figure 6-30 WASP Operation Sequences [57]

6.4.2. Suspended Well Abandonment Tool (SWAT)

The SWAT system, which is owned by Claxton Engineering Service Ltd (Claxton), is designed to perform perforation, circulation and cementation of multiple casing annuli. It has been used to abandon wells in the UKCS since 1996. SWAT can be deployed through the moon pool of an RLWI vessel. The system is pressure rated to 5,000psi. The deepest cement plug set to date is 2400 ft (731 m) below mudline [56]. Figure 6-31 shows the configuration of SWAT.

In a well P&A activity, the operation starts as the tool lands in the 9-5/8" casing hanger. The upper and lower packer are inflated to make sealing. Then a test is performed to confirm the integrity of the seal. After that, the lower gun is fired hydraulically to breach the 9-5/8" casing and continue with the upper gun to create circulation path through the inner annulus. The cleaning fluid is then pumped down into the annulus through the circulation path to replace drilling mud. This mud is either recovered or discharged if it is water based [56].

The next step is cementing. Cement is pumped down through the upper perforation into the annulus and down to the lower perforations. After a period of waiting on cement (WOC), test is performed to verify the integrity.

After cementing the inner annulus, the outer annulus is cemented. The operation sequences are basically the same as before. However, the lower and upper gun are fired to perforate the 13-3/8" casing.

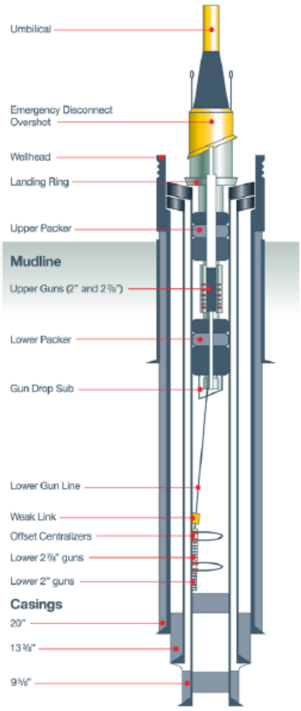


Figure 6-31 SWAT Tool [58]

<u>Comment</u>

SWAT and WASP have more or less the same function, which is to establish barrier inside of annulus or multi annulus. As mentioned before, the tools have been used in field to establish surface barrier. The tools are wireline based tools which can be run using RLWI vessel.

However, one of the disadvantages of the tools is that reservoir barrier has to be established before using this technology. Moreover, the tubing should be retrieved. Therefore, another tool must be used for reservoir barrier establishment and tubing retrieval. Another issue is this tool has a maximum water depth of 1,600 ft (490 m), so that it cannot be used in deep water (>500 m) [56]. Moreover, with the same reason as PWC technology, verification through multiple casing strings is also a challenge that needs to be solved with this tool.

Nevertheless, SWAT has proven track record and can be used with RLWI vessel.

6.5. Summary of Technology Evaluations

The following table gives a brief summary of the technologies that has been discussed in this thesis, with regards to the advantages and disadvantages.

Table 6-1 Summary of Technology Evaluations

Technology / Method	Pros	Cons
Production Tubing Considerations		
Left tubing in hole	- No need to retrieve tubing - No need to cut control lines	- Not field proven - Difficult cement placement technique
Control lines remover (Aarbakke Innovation)	- No need to retrieve tubing - Able to retrieve a section of control lines - Wireline based technology	- Not field proven - Could weaken the tubing
Cutting tubing section (Geo-STU)	- Wireline based technology - No need to pull production tubing - Could provide a window to log behind casing	- Not field proven - Difficult to locate control lines - Need to cut extensive length of tubing for surface barrier establishment
Tubing cutting & compacting (Oilfield Innovation)	- Wireline based technology - No section milling is needed - Could provide a window to log behind casing - No need to pull production tubing	- Not field proven - Big force might be needed to compact the tubing downward
Plasma-based tool	- No need to retrieve tubing - No section milling is needed - Higher milling rate	- Not field proven - High power might be needed
Reservoir Barrier Establishment and Circulation Path		
Riserless coiled tubing	- May be used for 90% – 100% of P&A operation - Allow circulation and rotation - May open alternative method for other technologies (PWC and plasma)	- Never been done in a live well - Fatigue issue - Corrosion issue - Difficult to create fluid circulation path - Difficult to establish well barrier - Complex system

Technology / Method	Pros	Cons
Riser based coiled tubing	- May be used for 90% – 100% of P&A operation - Allow circulation and rotation - May open alternative method for other technologies (PWC and plasma) - Well intervention operation has been done using the technique	- Never been done for P&A operation - Massive LWI vessel modification is needed
Thermite P&A method	- Wireline based technology - No section milling is needed - No need to pull production tubing - No cementing needed	- Not field proven - Barrier quality needs to be verified
PWC	- Proven technology - No section milling is needed - Barrier establishment through multiple casings - Possible to re-entry	- Tubing needs to be pulled - Plug verification can be challenging - Has never been done using LWI vessel
B & C Annulus Barrier Establishment		
SWAT/WASP	- Proven technology and track record - It can be deployed from RLWI vessel - Barrier establishment through multiple casings	- Tubing needs to be pulled - Only for surface barrier - Water depth max 1600 ft (490 m)

6.6. P&A with LWI Vessel using New Methods and Technologies

Island Offshore made a study in 2012 regarding the possibility of doing P&A operation using RLWI vessel. They made a detailed step-by-step description of a proposed well P&A according to NORSOK D-010. The description of the equipment needed and the procedure are presented in the Appendix. However, until today, the proposed solution has never been executed in field. This is because some of the equipment need qualifications. Furthermore, the industry still prefers the proven conventional method for P&A operation, that is using rig. With some of the new technologies offered in the industry, the possibility to perform the entire P&A operation using LWI vessel is improving. In this section, the application of the methods and technologies that have been described in this chapter for P&A operation is discussed.

6.6.1. The Concept

As described before, there are a lot of new methods and technologies available to be applied in P&A operation. Some of the technologies are riserless technology, others are riser based. Figure 6-32 summarizes the technologies that have been discussed in this thesis.

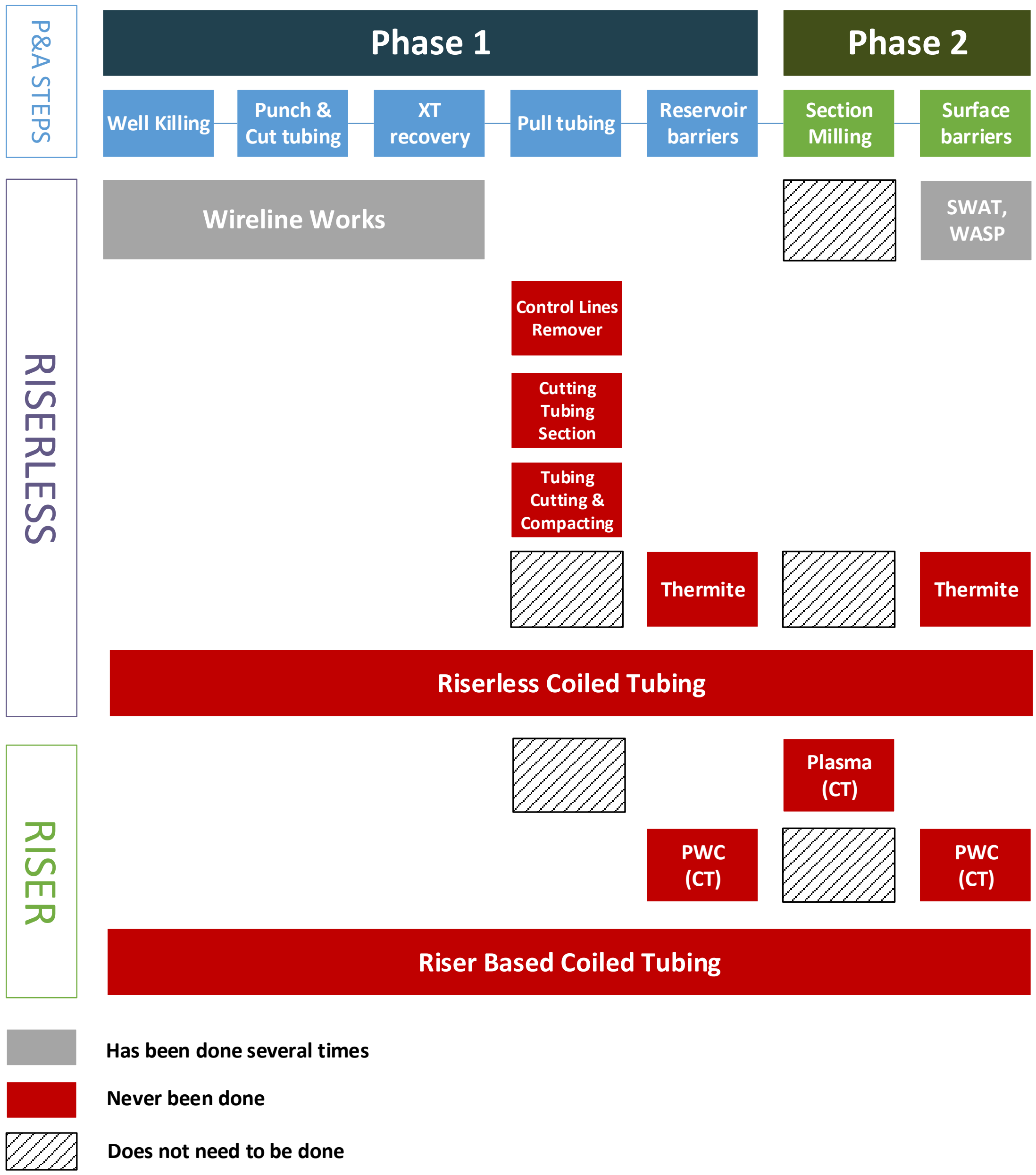


Figure 6-32 P&A Methods & Technologies to be Applied in LWI Vessel

The current method of P&A can be represented by the third line of boxes (grey box). Some activities for the phase 1 of P&A, such as killing the well by bullheading; punching and cutting the tubing; and recovering the Xmas tree have been done a couple of times using LWI vessel. For pulling tubing and reservoir barrier establishment, drilling rig is used. The figure does not show the phase 3 of P&A operation, which is wellhead and conductor removal, because it has been done several times using LWI vessel (riserless) with technology that was described in section 4.2.5.

The red boxes contain the methods and technologies that have been described within this thesis. As mentioned before, pulling tubing is one of the main reasons that rig is still used for P&A operation. Therefore, several technologies have been proposed to avoid or minimize the tubing retrieval operation.

In general, the proposed methods of P&A operation using LWI vessel can be divided into two; riserless and riser based. For the riserless operation, a regular LWI vessel such as provided by Island Offshore (Figure 2-6 Island Offshore Category A VesselsFigure 2-6), can be used. However, the scenario is different for the riser based method. Some modifications are needed to accommodate the riser and coiled tubing. Furthermore, extra equipment for fluid circulation, mud system, and cementing unit are needed. This is an engineering optimization issue that can be solved by clever modularization for various deck areas.

For the riserless operation, in the author's opinion, the most promising technology is the thermite P&A method. It is a wireline based technology, thus, it can be used in general LWI vessel. No rig, cement, and coiled tubing are needed. With the advantages that have been discussed, it probably could become the 'game changer' in the P&A operation. As can be seen in Figure 6-32, pulling tubing and section milling can be avoided. Without pulling tubing and section milling, the operation time can be significantly cut. Furthermore, this technology could establish reservoir, intermediate, and surface barrier. However, this technology needs to undergo extensive testing, qualification, and field trials. It is expected that in the next 5 years that this technology will be fully qualified.

Other riserless technologies with the concept of avoiding tubing retrieval operation have been described. As mentioned before, the operation is one of the greatest challenges of P&A operation using LWI vessel. In Figure 6-32, these riserless technologies are mentioned in red boxes, under the 'pull tubing' box. Leaving the production tubing is an option, although extensive field tests are needed. 'Control lines remover' by Aarbakke Innovation, 'cutting a section of tubing' by Geoprober, and 'cutting and compacting tubing' technologies by Oilfield Innovation offer solutions for tubing removal issue. However, currently, those technologies are still in conceptual stages. In the author's opinion, those concepts have less chance of succeeding compared to the thermite method by Interwell. This is because those technologies do not solve the barrier establishment issue. The circulation path is still needed for the barrier establishment operation.

Riserless coiled tubing could become the solution in the future, but currently, the system has not developed beyond the conceptual stage.

For the riser based P&A operation, the application of coiled tubing extends the range of operations that may be performed. With the advantages that have been previously described, most of the P&A operations can be done with coiled tubing operation. Combining with other technology, such as the plasma-based tool, the tubing may be left inside. The plasma tool is capable of creating a window for barrier establishment by melting the tubing and the casings. It replaces the section milling operation as shown in Figure 6-32. After that, the barrier could be established by coiled tubing. Without section milling, a formation-to-formation barrier could be established as per requirement. However, the plasma-based tool needs to go through comprehensive qualifications and field trials.

PWC technology has some track records in establishing annulus barrier. However, there is one major issue, the tubing needs to be pulled. This tool could, however, be used to establish barriers in a temporary abandoned wells, that have the tubing removed. Although coiled tubing is needed, PWC technology could become a solution for some special case of subsea temporary abandoned wells.

In the author's opinion, currently, the best chance of succeeding P&A operation using LWI vessel is to use a small bore (~7") riser. Although significant modifications are needed on the vessel, the system is relatively less complex and circulation path may easier be established. A bigger vessel compared to the examples shown in Figure 2-6 may be needed with a higher capability of handling heavy equipment.

6.6.2. The Restrictions

There are currently several restrictions that could become obstacles in performing P&A using LWI vessel. They will be discussed in the following sections. Some of the restrictions below are not directly related to the LWI vessel operation but has relation with the P&A operation in general.

6.6.2.1. Missing Technology

In the author's opinion, the main missing link that limits the possibility of performing P&A using LWI is the technology to log multiple casings. To be able to see the current condition of the well is one of the most important things in the P&A operation. As discussed before, most of the wells to be abandoned are old, thus, they are time deteriorated. Furthermore, the original documentations or drawings are not reliable. Therefore, verification by logging through multiple casings is needed. The inability to log through multiple casings is also one of the main reasons to pull the production tubing during P&A activity.

6.6.2.2. Reluctance to Apply New Technologies

A lot of new technologies are developed for P&A operations. However, most of them have never been used in field. Some of the concepts have already been introduced years ago but there is some hesitation in applying it. This is understandable because P&A is a high-risk operation. Safety is a priority, thus proven conventional methods still become the first choice in some P&A operations. However, new technologies depend on field tests to prove that the method will work. If all companies just wait until the technology is proven without trying to prove it themselves, the time required to qualify the technology will become longer. Consequently, the good concepts may disappear before going to the market.

However, currently, there is already a general awareness in the world that well P&A is something to be faced. Open collaboration between companies (operators) and service providers is recommended to identify the best technologies, combining safety and economics, as the best P&A solutions.

6.6.2.3. Regulations

The regulations may need to be changed in order to apply some new technologies. For example, the thermite method. It may be difficult for the tool to follow the minimum length requirement. Therefore, rules and regulations may have to be adapted to the new methods.

6.6.2.4. Uncertainties

There are a lot of uncertainties in performing P&A using LWI vessel. Each well is unique, thus need different methods to plug and abandon it. The existence of documentation of barrier log, placement of cement barrier, and tubing integrity could affect the possibility of performing P&A using LWI vessel. If the tubing is damaged so that the access is restricted, it is difficult to use LWI vessel.

Weather can also be part of the uncertainties. LWI vessel has more weather limitation compared to semi-sub rig with respect to motion characteristics.

7. Conclusions & Recommendations

7.1. Conclusions

Considering a large number of wells required to be permanently abandoned in the near future, a cost-effective method of P&A operation is needed. P&A operation has no economic gain. The transition of P&A operation using rig into LWI vessel must be started in order to reduce the cost of the operation. In this thesis, several methods and technologies have been presented to be applied in LWI vessel.

There are several main challenges of P&A operation using LWI vessel. The first one is to establish the reservoir barrier. Circulation path from the vessel to the well needs to be established to set the reservoir barrier. The second challenge is the tubing retrieval activity. Although the tubing may be left inside, there are several reasons for the tubing to be retrieved. The existence of control lines is one of the main reasons. They may create a vertical leak path while cemented in. The third challenge of P&A operation using LWI vessel is the establishment of B and C annulus barrier. Currently, there is no technology to check the quality of cement inside multiple casings. Thus, section milling is conventionally required for the barrier establishment.

In general, there are two solutions to solve the challenges of P&A operation using LWI vessel; it is either with riser or without riser (riserless) operation. Thermite solution by Interwell could become the best option for the riserless P&A operation using LWI vessel. The tool is designed to be deployed by wireline, thus, the available LWI vessel can be used. By melting the surrounding materials inside the wellbore, all of the required barriers can be established, solving of the barrier establishment issue in P&A operation using LWI vessel. Furthermore, the production tubing could be left inside, so the challenge related to the tubing retrieval can be avoided. However, several field qualifications are currently needed before this tool could become the real solution of P&A using LWI vessel.

Another option for riserless P&A using LWI vessel is by qualifying riserless coiled tubing operation. This system is promising but currently, the system is not yet developed to be used for P&A operation in a live well. Development is needed for this technology.

Coiled tubing is mainly used for the riser based P&A operation using LWI vessel. Most of P&A operation can be done by the coiled tubing. The coiled tubing allows higher mechanical force than wireline. Moreover, fluid circulation is possible using the system. To accommodate the riser system and coiled tubing equipment, significant modifications will be needed in the LWI vessel.

The plasma-based tool may be deployed with coiled tubing to create a window for barrier establishment, thus eliminating section milling operation. The tool can be run through the tubing and melt the tubing together with the casings, thus solving the tubing retrieval challenge. The barrier establishment then can be done by coiled tubing operation. The riser based system have a better prospect with respect to the availability of the technology, although the plasma-based tool needs extensive field tests and qualifications at the present.

Regarding the restrictions and limitations, in the author's opinion, currently, an RLWI vessel can do 50 – 60% of the P&A activities. Some of the first phase activities of P&A, such as well killing until Xmas tree retrieval can be done using an RLWI vessel. The last phase of P&A, which is wellhead and conductor removal, is also executable using an RLWI vessel. And the rest 40 – 50% of the activities are currently executed by a drilling rig. However, it is important to note that splitting a P&A operation into several campaigns might not be a cost-effective solution. It could, however, be done in multiple batch operations to make it into a cost-effective solution. Thus, cooperation between operators is needed.

At the same time, the LWI vessel with riser (~7") and coiled tubing equipment, combining with the technologies described in this thesis, could do 70 – 100% of the P&A operations. Significant modifications of the vessel will, however, be needed. In addition, an upper range size vessel that is capable of handling the heavier equipment might be envisaged for the extended range of operations.

7.2. Recommendations

There are several recommendations that might improve the future P&A operations. In below section, the recommendations are discussed.

7.2.1. Coiled Tubing Operation

One of the recommendations is to develop methods of applying coiled tubing operations for P&A activity, considering both riser based and riserless solutions. As discussed in this thesis, with the use of coiled tubing, circulation path can be established. Thus, the well can be cleaned out and cement barrier can be established. Therefore, it is important to evaluate and develop the technology to be used in an LWI vessel.

7.2.2. Purpose-Built P&A LWI Vessels

Another recommendation is to develop a purpose-built LWI vessels for P&A operations, with the circulation path establishment and other equipment to satisfy the operational requirements. Subsea light well intervention have been successfully executed for more than 15 years using

RLWI vessels. Therefore, it is recommended to study and develop a new vessel, with better motion characteristics, for P&A purpose. Considering the number of wells to be plugged in the next decades, developing a smaller and cheaper vessel purely for the P&A activity could become a cost-effective solution.

7.2.3. Development of Key Missing Technologies

The next recommendation is to develop the key missing technologies. For example, the technology to log multiple annuli. If the tool is available, the cement behind casings can be verified. Therefore, in some cases section milling will not be needed, if the quality of the cement inside the annulus is acceptable. Thus, there will be a higher chance in performing P&A operation using LWI vessel

7.2.4. Future Well Design

Another recommendation is to include P&A strategy in the future well design and installation. During completion stage, annulus cement barrier may be established in the location where the seals are needed to be placed for future P&A. The quality of cement behind casing could be verified and documented during drilling and completion stage.

7.2.5. Rules and Regulation Adaptation

The last recommendation is to modify the rules and regulations so that they can facilitate the introduction of new technologies.

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Appendix

A Study of P&A Operation Using RLWI from Island Offshore

Island Offshore had made a study in 2012 regarding the possibility of doing plug and abandonment operation using RLWI vessel. In this appendix, the equipment needed and the procedure will be described.

Equipment

Within this section, the additional equipment needed apart from the standard equipment on RLWI operation (that is described in section 2.2.4) will be discussed.

Subsea Shutoff Device

Subsea Shutoff Device (SSD) is an equipment that is designed as a well barrier equipment to replace a standard drilling BOP. Figure 1 shows the picture of the equipment. With the same function as a standard BOP, SSD also has the ability to shear, seal, and control the well in the event of an incident.

This equipment is needed during the tubing retrieval operation. During the tubing retrieval operation, the standard RLWI stack cannot meet the minimum requirement as the well barrier equipment and also is not suitable for the operation.

Figure 1 Subsea Shutoff Device (SSD) [59]

The configuration of the equipment as Island Offshore proposed as a well barrier equipment is as follows (from bottom, Figure 2) [16]:

- Wellhead Connector
- Shear / Seal Ram (1)
- Kill Line (w/pressure reading)
- Spool Piece with THROT orientating pin
- Shear / Seal Ram (2)
- Choke Lines (w/pressure reading)
- Annular BOP
- Wellhead mandrel

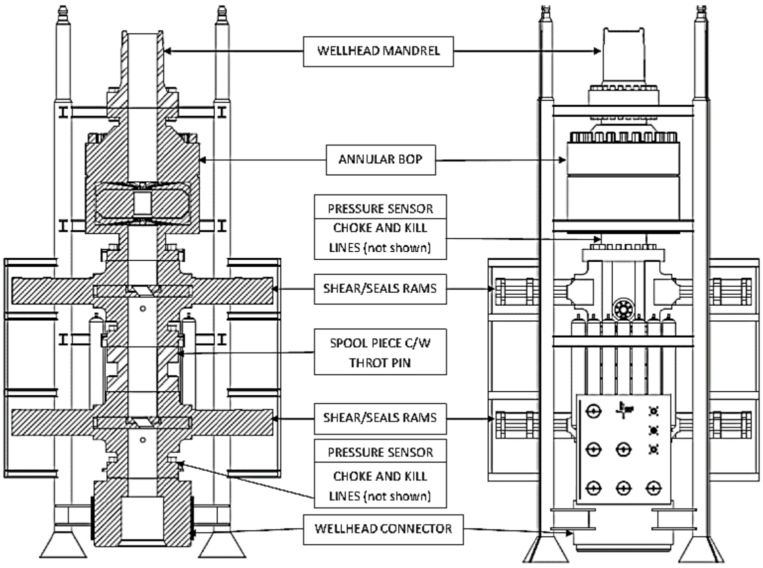

Figure 2 Illustration of Standard SSD [16]

Volume Control System (VOCS)

Another unit that is needed is Volume Control System (VOCS). The VOCS monitors and controls the overall volume of fluid in the well as materials are added and removed in the wellbore during P&A operations. The VOCS utilizes subsea sensors and pumps to measure, remove and replace fluids from the wellbore [60].

Figure 3 illustrates the configuration of the system. As shown in the figure, the system contains pumps and level controls. The system is also equipped with sensors for level control with alarms system, light and camera on top of the funnel for continuous surveillance of the fluid level. Therefore, gaining or loosing fluids inside of the well can be recognized.

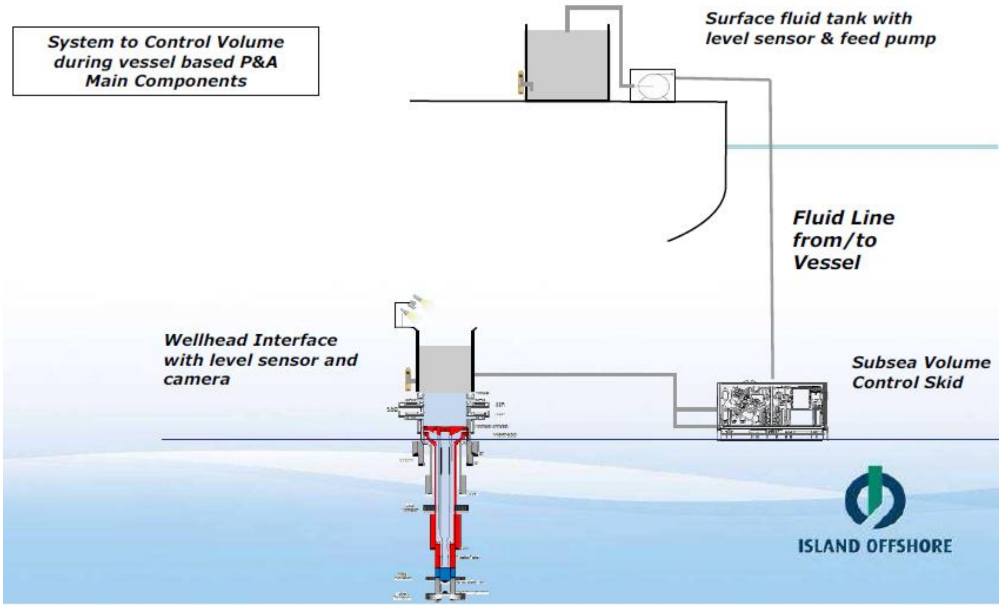

Figure 3 Volume Control System Configuration [59]

Cement Adapter Tool (CAT)

CAT has more or less the same function as SWAT and WASP that have been reviewed in chapter 6.4. It can be used in P&A operations on wells that have one or two annuli un-cemented.

The operational sequences of establishing barrier inside the annulus using CAT is as follow (Figure 4):

a) The CAT tool is run and installed together with LWI Well Control Package. In combination with the LWI Well Control Package, it can maintain 10K pressure rating well barriers/control during operations.
b) Perforation gun is run through the LWI-stack and the CAT. Then perforates lower and upper part of the casing to create communication path in the annulus.
c) A packer is run to seal between upper and lower perforation then continue with cleaning the annulus through the circulation route.
d) Cementing

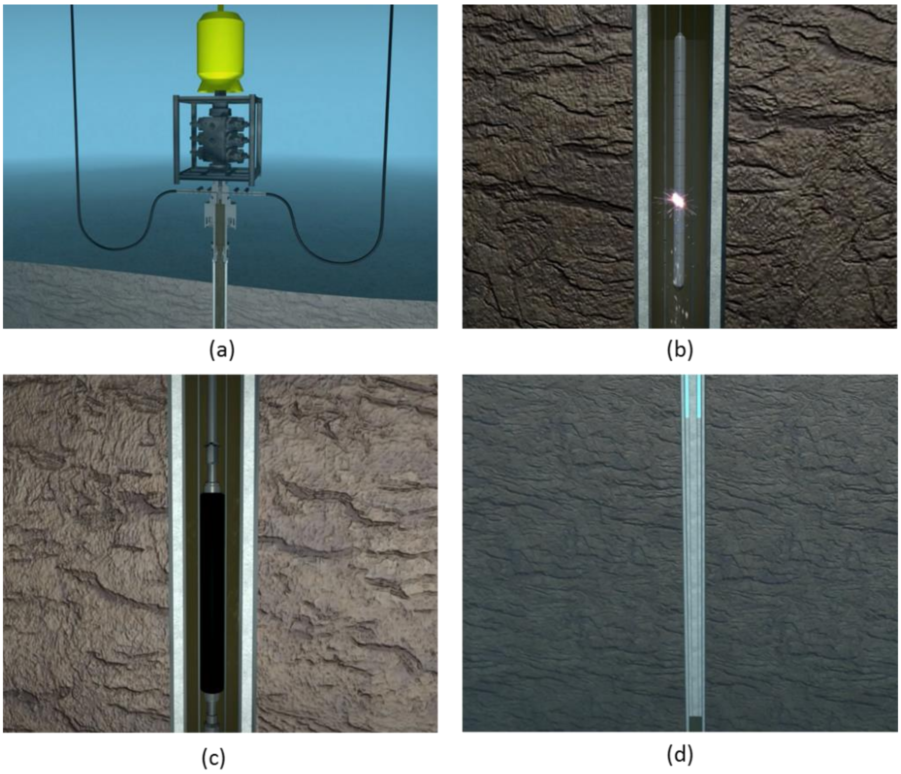

Figure 4 CAT Operation Sequences [61]

One advantage of using this tool is that it has no limitation of depth because wireline can run through the RLWI well control package and CAT allowing it to perforate in the desired depth. Moreover, sufficient barrier can be established to install primary and secondary plug with the RLWI well control package on it.

Cement Spool

Another unit that is needed is a Cement Spool. Through tubing bullheading and squeeze of cement is possible with this tool. Figure 5 illustrates the cement spool. The cementing job is performed before Xmas Tree removal. It has a line connection for transferring cement from the vessel. The return line is achieved via the annulus.

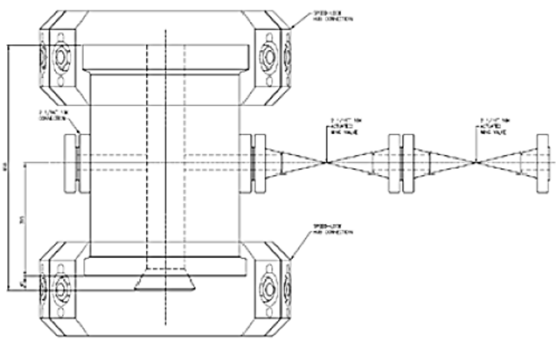

Figure 5 Cement Spool [16]

Procedure

In this section, a brief Island Offshore procedure of the P&A operation with RLWI vessel will be discussed. In this scenario, a vertical Xmas tree is installed.

Phase 1 – Reservoir Abandonment

During this phase, the first subsea equipment configuration consists of a standard RLWI stack (which consist of Well Control Package (WCP), Lubricator Section (LS), Pressure Control Head (PCH)) with a Cement Spool on bottom of it. The steps for this phase is as follow:

1. Log liner annulus cement and continue to set mechanical plug below perforations as a cement plug foundation.
2. Squeeze 200 m cement plug (primary & secondary barriers) through the Cement Spool as illustrates in Figure 6 left.
3. Punch tubing above production packer to get annulus access and circulate well to weighted fluid.
4. After having the tubing cut, the subsea equipment (RLWI stack and cement spool) is pulled with the Xmas tree. Install SSD and Volume Control System on top of it as illustrated in Figure 7 left side.
5. After the stacks installed, the operation continues with pull production plug, unlock tubing hanger, pull tubing and set bridge plug (Figure 7 right). This phase is completed after the tubing is pulled out.

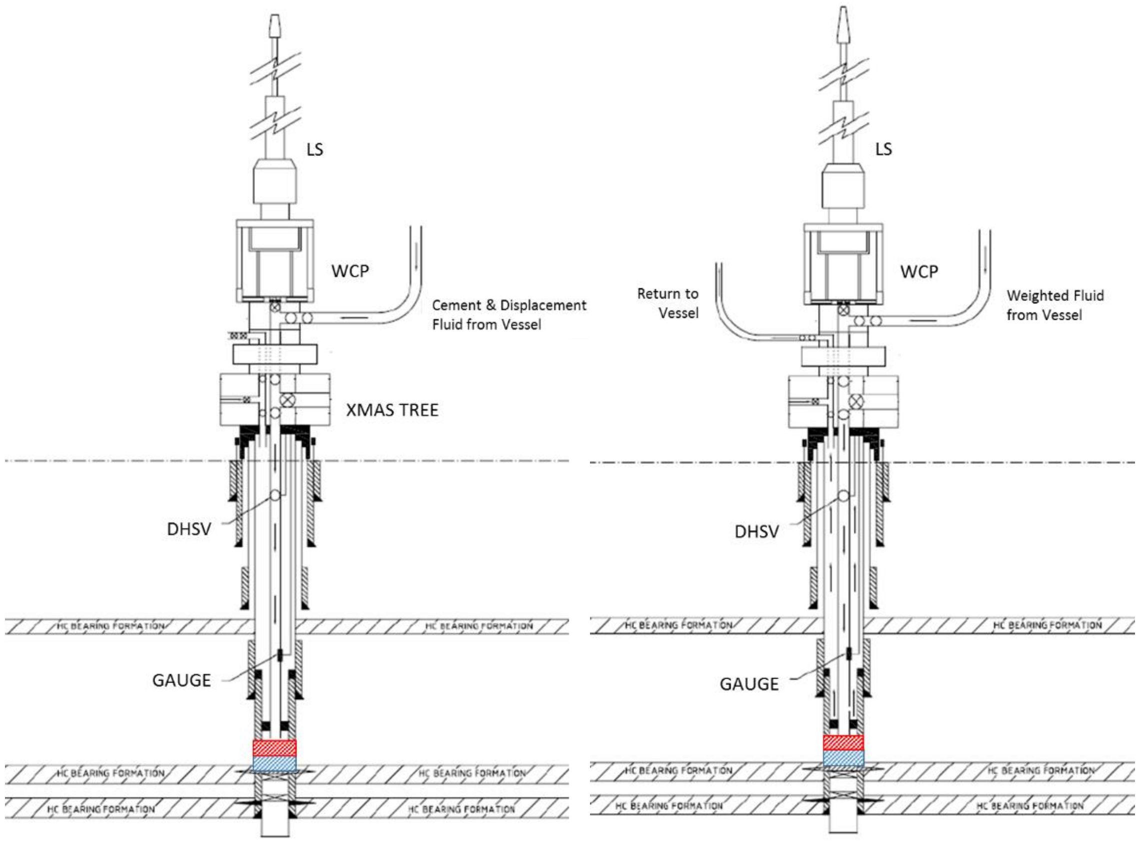

Figure 6 Reservoir Barrier Establishment (left) and Punch Tubing (right) [59]

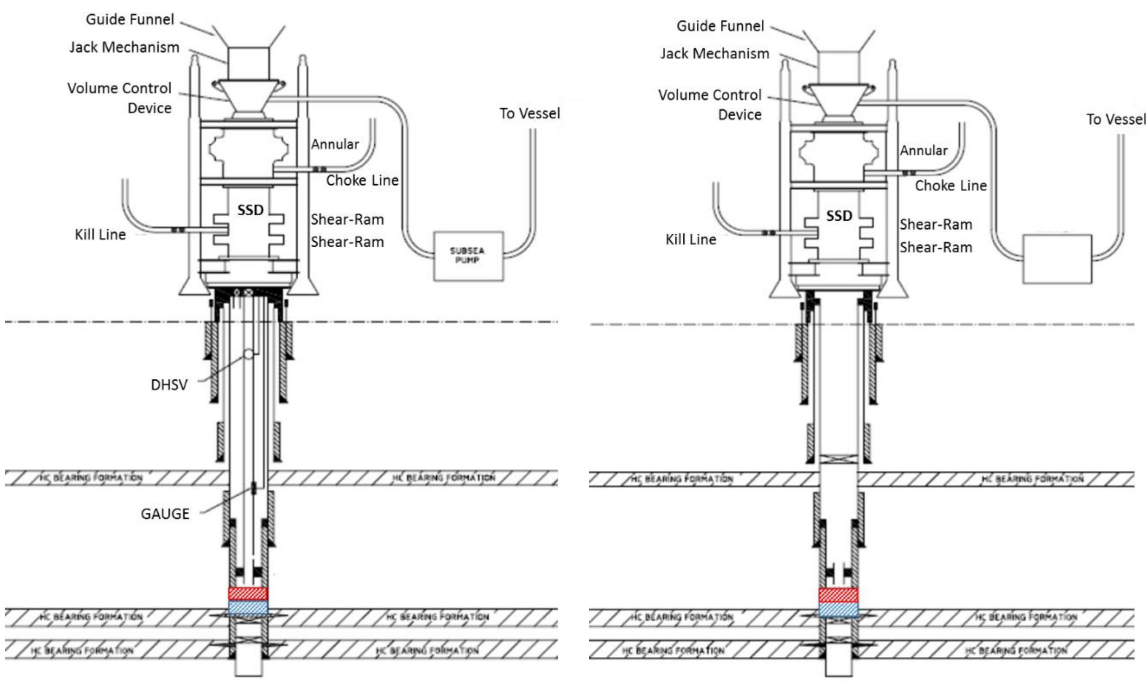

Figure 7 SSD and Volume Control System Device (left) and Production Tubing Pulling (right) [59]

Phase 2 – Intermediate Abandonment

In this stage of P&A operation, the barrier establishment for the next reservoir zone will be done. Open hole to surface barrier is also installed in this phase. The subsea equipment stack that is installed are the RLWI stack and also the Cementing Adapter Tool (CAT). The steps are:

1. Perforate 9-5/8" x 13-3/8" annulus, circulate, and set upper combined annulus, primary & secondary barrier with the CAT tool.
2. Set foundation for open hole to surface plug in 9-5/8" casing.
3. Install stinger, perforate 9-5/8" x 13-3/8" annulus, circulate and set annulus squeeze plug
4. Perforate 13-3/8" x 20" annulus and circulate (Figure 8 left).
5. Set 13-3/8" x 20" annulus balanced plug, using CAT (Figure 8 right).

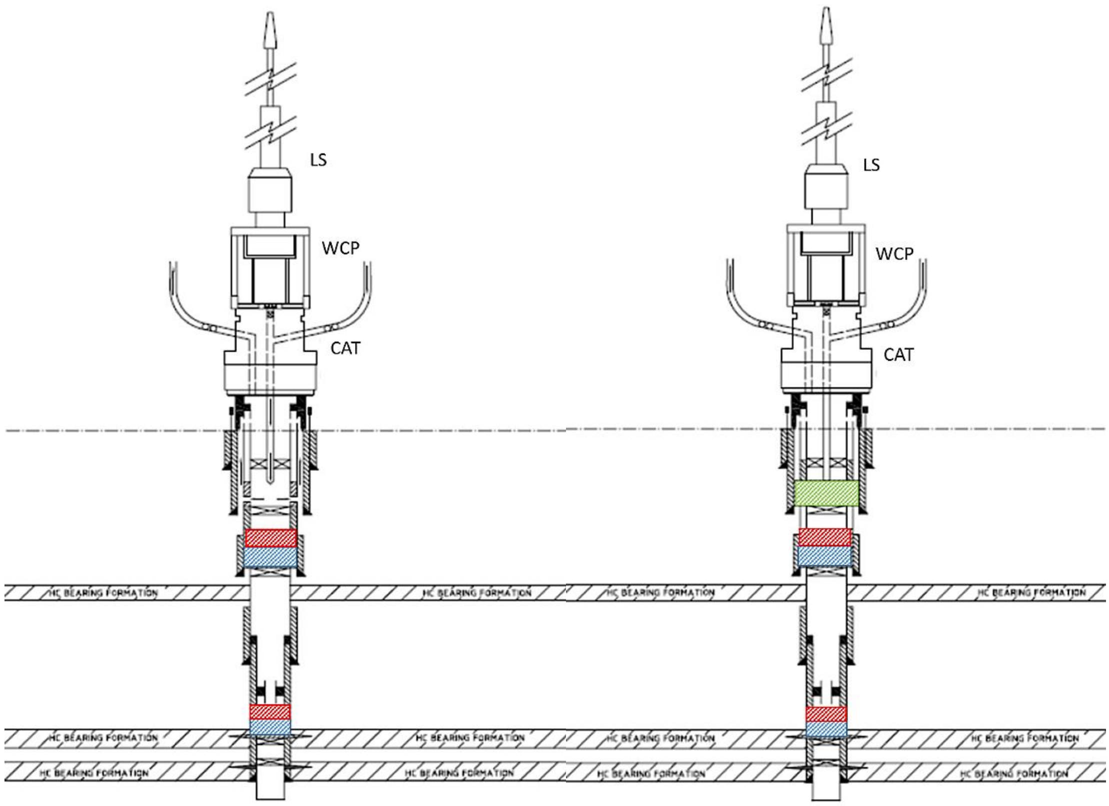

Figure 8 Perforation and Open Hole to Surface Barrier Establishment [59]

Phase 3 – Wellhead and Conductor Removal

The last phase is to cut the conductor (5 m depth) and retrieve the wellhead. The operation is done using abrasive water jet cutting tool. Figure 9 shows the configuration of the well after being plugged.

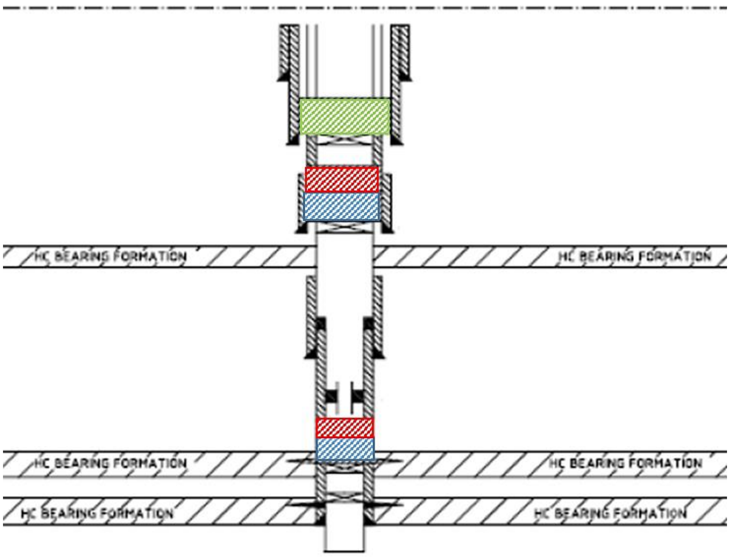

Figure 9 The Well After Plugged [59]