University of Stavanger

Faculty of Science and Technology

MASTER THESIS

Study program/ Specialization: **M.Sc. Well Engineering**	Spring semester, 2013 **Open**
Writer: **May Bente Leifsen Valdal**	May Bente Leifsen Valdal

Faculty supervisor: **Kjell Kåre Fjelde, University of Stavanger**

External supervisor: **Silje Slettebø, Statoil ASA**

Title of thesis:

Plug and Abandonment Operations Performed Riserless using a Light Well Intervention Vessel

Credits (ECTS): 30

Key words: P&A operation, New technology, Logging challenges, Control cables, Coiled Tubing performed from a RLWI vessel, Barrier material, Barriers throughout operations	Pages: 98 + enclosure: 15 Stavanger: 13-June-2013

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Abbreviation

AWJC	Abrasive Water Jet Cutting
BAR	Borehole Acoustic Reflection
BHA	Bottom Hole Assembly
BSS	Black Sticky Stuff
CAT	Cement Adapter Tool
CBL	Cement Bond Log
CCL	Casing collar locater
CIS	Casing Integrity System
CT	Coiled Tubing
DHSV	Downhole Safety Valve
EXHT	External horizontal tree
GR	Gamma Ray
HXT	Horizontal X-mas tree
IMCT	Internal Multi-String Cutting Tool
IO	Island Offshore
LLP	Lower Lubricator Package
LS	Lubricator Section
N.C.S	Norwegian Continental Shelf
P&A	Plug and Abandonment
PP&A	Permanent Plug and Abandonment
PWT	Perforate & Wash tool
RLWI (LWI)	Riserless Light Well Intervention
SIL	Subsea Intervention Lubricator
SWAT	Suspended Well Abandonment Tool
TCP	Tubing Conveyed Perforation
TDC	Tree Debris Cap
TFL	Through Flow Line
TH	Tubing Hanger
THCP	Tubing hanger Crown Plug
THERT	Tubing Hanger Emergency Release Tool
THROT	Tubing Hanger Running and Orientation Tool
TOC	Top of Cement
TOGI	Troll Oseberg Gas Injection
TP&A	Temporary Plug and Abandonment
TR	Technical Requirement
ULP	Upper Lubricator Package
USIT	UltraSonic Imager Tool
VXT	Vertical X-mas tree
WASP	Well Abandonment Straddle Packer
WBE	Well Barrier element
WCP	Well Control Package
WL	Wireline
WOC	Wait on Cement
WOW	Waiting on Weather
XMT	X-mas tree

Terms and definitions

A-annulus: Annuli between the tubing and the production casing

B-annulus: Annuli between the production casing and the next casing strings

Coiled Tubing: Metal pipe, normally 1" to 3.25" in diameter, used for interventions in oil and gas wells and sometimes as production tubing in depleted gas wells, which comes spooled on a large reel

Electrical cable (e-cable): wire consisting of individual steel strands woven around one or more electrical conductors to provide sufficient strength to perform desired electrical work in well

Permanent well barrier: a barrier consisting of well barrier elements that individually, or in combination, creates a seal that has a permanent, and therefore eternal, characteristic.

Permanently abandoned well: a well, or part of a well that is plugged and abandoned with the intention that it will never be used or re-entered again. The intention is to abandon the well with an eternal perspective.

Potential source of inflow: formation with permeability, but not necessary a reservoir

Primary well barrier: first object that prevents flow from a source

Reservoir: Permeable formation or group of formation zones originally within the same regime, with a flow potential and/or hydrocarbon present or likely to be present in the future

Secondary barrier: Second object that prevents flow from source

Slickline: Slick string of uniform diameter with sufficient strength to convey WL tools to their operation depth

Well barrier element: An object that alone, with some exceptions, is not able to prevent formation fluids from flowing from one side to the other side of itself.

Well intervention: Collective expression for deployment of tools and equipment in a completed well

1 Acknowledgements

I would like to use this opportunity to thank several people for aiding me in the work with this Master Thesis. Among those is Kjell Kåre Fjelde, my supervisor at the University of Stavanger, who has given me very valuable and structural feedback throughout the Thesis work.

I would also like to acknowledge Silje Slettebø, my external supervisor from Statoil, for her good support throughout the Thesis and also thanks to the rest of Statoil team for exciting discussions around technical and operational aspects.

Amongst service Companies I would thank Island Offshore, Welltec, HydraWell, Archer and Halliburton for releasing information on new technology for this Master Thesis.

Finally, I will thank my family who motivated me to finalize the master degree when desire and motivation were not present.

2 Abstract

In a few years there will be a significant increase in wells that need to be permanently plugged and abandoned (PP&A). Statoil operates around 500 subsea wells on the Norwegian Continental Shelf (N.C.S), whilst there exist around 5000 subsea wells worldwide. Some older wells could be extremely challenging to plug, since abandonment requirements were not taken fully into account when the wells were planned, drilled and completed. In later years new requirements have also been implemented for plug and abandonment.

Statoil has now increased focus on Plug and Abandonment (P&A), this Thesis is written by request by Statoil.

Due to continuing high oil prices, new field discoveries and general optimism in the market, there is currently a shortage of conventional semi-submersible rigs. The future demand for more semi-submersible rigs or other alternatives is likely. For a permanent plug and abandonment operation the main goals are to complete the operation of the well in a safe and cost-effective manner. In this context it is anticipated that some wells could be abandoned in the future solely by a monohull Riserless Light Well Intervention vessel (RLWI). The day rate of a RLWI vessel is significantly less expensive than for an ordinary rig. Traditionally, P&A on subsea wells are intervened by semi-submersible rigs with marine risers. To perform the P&A operation from a RLWI vessel, the development of new technology to overcome some challenges is required. The main challenges demanding new technology identified today includes how to establish the primary and secondary barriers in wells which contain control lines attached to the tubing, and/or wells where the outer barrier element, i.e. the casing cement, is either not verified, not present or in poor condition, and the possibility to remove the tubing and placement of the barrier.

The scope of work for this Thesis has been to show that the final plug and abandonment operations that are conventionally being performed using semi-submersible rigs can be performed entirely from a RLWI vessel. The focus has been on equipment and methods to manage to execute the operation. The P&A operation is premised executed with required barriers in place during entire operation and for less cost than for a rig. The Thesis will identify the gaps in technology, attempting to identify status and propose possible solutions, look into the possibility to use Coiled Tubing on a light well intervention without a marine riser, and operations and weather analysis behaviour of semi-submersible rigs and RLWI vessels.

This Master Thesis will describe how it would be possible to perform a final plug and abandonment job using a RLWI vessel, and address further technology development needed for RWLI P&A operations. The new operation would lead to more cost efficient P&A operations for subsea wells. The semi-submersible rigs can thus focus on drilling and completion of new wells and thus increase the efficiency of the total well cycle of well planning, well construction and P&A, and thereby increase the revenue for the operating companies.

3 Introduction

Subsea production was first introduced on the Norwegian continental shelf in the early 1970's. Statoil decided already at its first development to focus on subsea production [66]. The first projects focused mainly on whether it was possible to move production systems from the platform deck to the seabed. Tommeliten was the first Statoil field that adopted a subsea production system in the form of a template design for multiple wells.

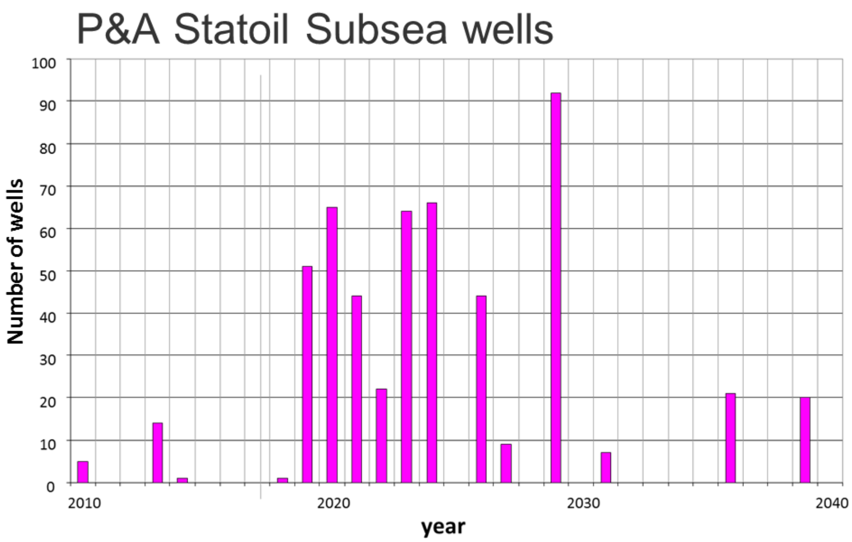


Figure 1 Future projections of number of subsea wells ready for P&A [72]

Statoil operates approximately 500 subsea wells on the Norwegian continental shelf (N.C.S) [App F]. It is anticipated that during 2020 more than 60 wells will need to be permanently plugged.

In recent years there has been an increasing trend towards wells with "smart" completions (e.q. with sensors and remote operated downhole valves requiring multiple control and/or signal lines).The older wells are coming to the end of their life cycle and need to be permanently plugged. Old wells can be challenging to plug, due to the fact that abandonment was not taken into account during the planning of the wells, at the same time smart wells will increase the complexity due to hydraulic lines. Plug and abandonment requirements have been upgraded and improved during the recent years.

The main goals for all regulations in a plug and abandonment perspective are to prevent fluid migration from reservoir to the surface as well as crossflow into another reservoir. In addition, there is also a requirement that there shall be no trace of drilling and well activities on the seafloor after leaving the area.

The Norwegian Petroleum Safety Authority (PSA) uses the following regulatory hierarchy and makes references to guidelines and recognized national and international standards for more detailed requirements [2]:

- The Norwegian Petroleum Safety Authority (PSA) Regulations
- Guidelines (to the regulations)
- National and international standards that are referenced in the guidelines, such as NORSOK standards, ISO standards, API standards, and IEC standards.
- Companies own regulations. In Statoil: ARIS with work process and technical requirements

Generally, in the North Sea, the main international standards that govern the P&A process are NORSOK [30] and UKOOA [73].

<u>Abandonment of wells can be divided into temporary and permanent abandonment [54]:</u>

A. Permanent abandonment: where the well or part of the well, will be plugged and abandoned permanently, and with the intention of never being used or re-entered again.

B. Temporary abandonment: where the well is abandoned and/or the well control equipment is removed, with the intention that the operation will be resumed within a specified time frame (from days up to several years)

<u>Three reasons for abandoning wells:</u>

1. Cease of production. The wells will be PP&A when it is no longer profitable to produce from a well or to re-use part of the well.
2. Slot recovery. This process involves permanent plug and abandonment of the old well track prior to sidetrack drilling into a fresh area of the reservoir. The main difference between 1 and 2: In slot recovery operations one typically cut and pull the 5 ½" / 7'' tubing, 9 5/8'' casing and also in some cases the 13 3/8'' casing. This is done in order to get maximum well diameter for the new well bore. In a permanent P&A without sidetracking it is strictly only necessary to pull the tubing (as long as outer barriers are intact).
3. Abandonment of pilot holes and exploration wells. The hole is plugged and abandoned immediately after being drilling and tested. No completion installed.

In order to extend the life time on a number of fields, several well slots on production platforms and on the subsea templates are being re-used. An overview of expected cease of production and amount of wells necessary to be plug and abandonment is available in App A.

The focus on this Thesis has been on the final plug and abandonment operation where no sidetrack is involved.

Today semi-submersible rigs are performing the permanent plug and abandonment (PP&A) for subsea well. Due to high oil prices, new field discoveries and a general optimism in the market there is already a shortage of drilling rigs. An important part of this Thesis has been to evaluate the technologies needed to perform PP&A operations from a Riserless Light Well Intervention (RLWI) vessel. A RLWI vessel is a boat that can perform intervention on live subsea wells. All standard wireline operation can be performed from the RLWI vessel. The present day cost for a RLWI vessel is significant less compared with semi-submersible rigs. There is no marine riser (as for a rig) for a RLWI vessel. Chapter (5) gives a general introduction to RLWI operations as well as categorization of a semi-submersible rig and RLWI vessel.

<u>The main steps in a conventional plug and abandonment solution</u>

a. Connect to the wellhead or XMT
b. Kill and secure well
c. Remove XMT
d. Cut tubing
e. Pull tubing
f. Plug and abandon well. Primary and Secondary barrier plug.
g. Establish open hole to surface barrier
h. Cut and retrieve wellhead

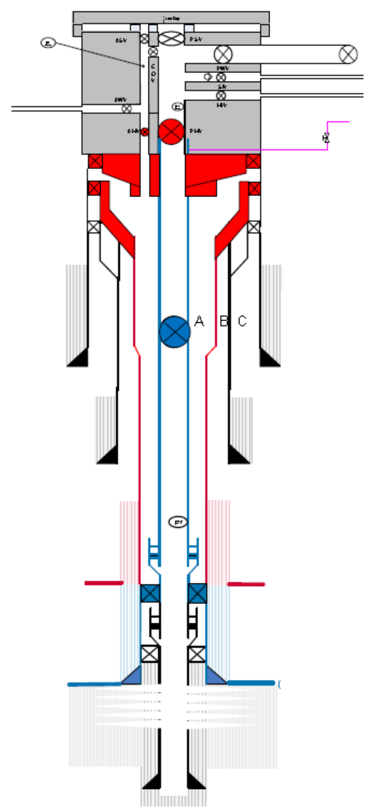


Figure 2 Well X will be used as an example for P&A operation

Key challenges during plug and abandonment operation using a RLWI vessel:

a. Removal of control lines
b. Verification of the casing cement
c. Removal of tubing
d. Install barrier plug
e. Use of Coiled Tubing package without riser

This Thesis covers:

- Requirements for a P&A operation, Chapter (4)
- Explanation of the main differences between units for P&A purpose and introduction to RLWI operation, Chapter (5)
- Main steps in final P&A operations and experience from RLWI vessel, Chapter (6)
- Identification of the technology challenges in P&A operation for RLWI and semi-submersible rigs, Chapter (7)
- Logging challenges identification. Cement bond logging through multiple casing strings, log cement behind casing with tubing partly retrieved and identify control lines behind the tubing, Chapter (8)
- Technology for cutting of tubing and control lines, presentation of different cutting alternatives, Chapter (9
- Different approaches for removing tubing. Cut and retrieve tubing to surface, or remove part of the tubing with crushing, chemicals and melting in well, Chapter (10)
- Coiled Tubing operation performed riserless from a light well intervention vessel, Chapter (11)
- Different approaches for installation of barriers, with or without use of Coiled Tubing, Chapter (12)
- Barrier materials, standard material used for Statoil and new plugging barrier materials, Chapter (13)
- Technology for other P&A operations. Removing of wellhead and alternative to logging, Chapter (14)
- Perform a full P&A using RLWI vessel on a well X to demonstrate use of some of the equipment and prove that the operation is possible to perform with two barriers throughout the operations, Chapter (15)
- An analysis of weather and the behaviour of semi-submersible rigs and RLWI vessels, compare operation time, operation factor and analysis of the effect of the period and wave height considering waiting on weather, Chapter (16)
- Cost and benefits of use of RLWI vessel compared with a semi-submersible rig, Chapter (17)

4 Requirements for plug and abandonment operations

In this Chapter the essential requirements and key issues for plug and abandonments are described.

Permanently plugged wells shall be abandoned with eternal perspective. There are several barriers to be installed and tested to fulfil a permanent plug and abandonment operation. The table below show the necessary barriers to be installed when plug and abandonment a well.

The requirements for plug and abandonment operations are in accordance with requirements given in NORSOK D-010 and Statoil TR3507.

Table 1 Barriers function and purpose [30]

Name	Function	Purpose
Primary well barrier.	First well barrier against flow of formation fluid to surface, or to secure a last open hole.	To isolate a potential source of inflow from surface.
Secondary well barrier, reservoir.	Back-up to the primary well barrier.	Same purpose as the primary well barrier, and applies where the potential source of inflow is also a reservoir (w/flow potential and/or hydrocarbons).
Well barrier between reservoirs.	To isolate reservoirs from each other.	To reduce potential for flow between reservoirs.
Open hole to surface well barrier	To isolate an open hole from surface, which is exposed whilst plugging the well.	"Fail-safe" well barrier, where a potential source of inflow is exposed after e.g. a casing cut.
Secondary well barrier, temporary abandonment	Second, independent well barrier in connection with drilling and well activities.	To ensure safe re-connection to a temporary abandonment well, and applies consequently only where well activities has not been concluded

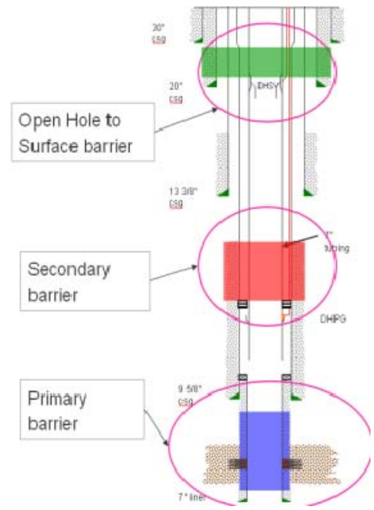


Figure 3 PP&A well with barriers in place [59]

Presently, Statoil only recognises cement and bonded shale (formation as barrier) as a permanent plugging material. Cement is originally made from limestone with some additives. The concept of using the formation as an annular barrier was formulated after several observations of bonding properties located above theoretical top of cement. Bonded shale is preferred used for permanent P&A, however the presence of bonded shale cannot be predicted. Therefore it shall always be planned for using cement as a barrier material outside casing. Further information regarding barrier materials can be found in Chapter (13).

Permanent well barriers shall extend across the full cross section of the well; include all annuli and seal both vertically and horizontally, *with a plugging material which can withstand the rigors of the environment to which it is exposed to [30].*

This is one of the key issues for PP&A operation performed from a RLWI vessel. Due to the full cross section barrier requirement, the tubing and the lines/cables need to be removed in some cases.

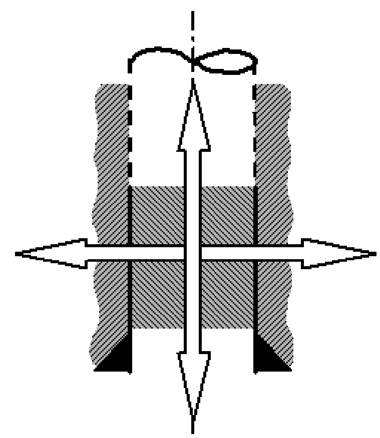


Figure 4 Barrier across the full cross section of the well [67

An internal well barrier element (WBE) shall be positioned where there is a verified external WBE (across all annuli). A minimum of 50 m cumulative interval is required to act as a permanent external barrier.

A permanent well barrier should have the following properties:

a) Impermeable, no formation fluid to move through the element

b) Long term integrity, eternal perspective

c) Non shrinking. If the barrier plug is shrinking fluids can leak through

d) Ductile – (non brittle) – able to withstand mechanical loads/impact.

e) Resistance to different chemicals/ substances (H2S, CO2 and hydrocarbons).

f) Wetting, to ensure bonding to steel.

Criteria to be fulfilled for a permanent barrier element:

1. The length of the cement barrier shall fulfil the following::
    a. The balanced set plug length shall be minimum 100 m MD
    b. Minimum 50 m cement with mechanical plug as foundation,
    c. 200 m Cement bond logging required when same cement job defines both primary and secondary annuli barrier element
2. Extend across the full cross section of the well
3. Positioned at a depth with a sufficient formation integrity (minimum formation stress)
4. Verification by logging, pressure testing and load test.

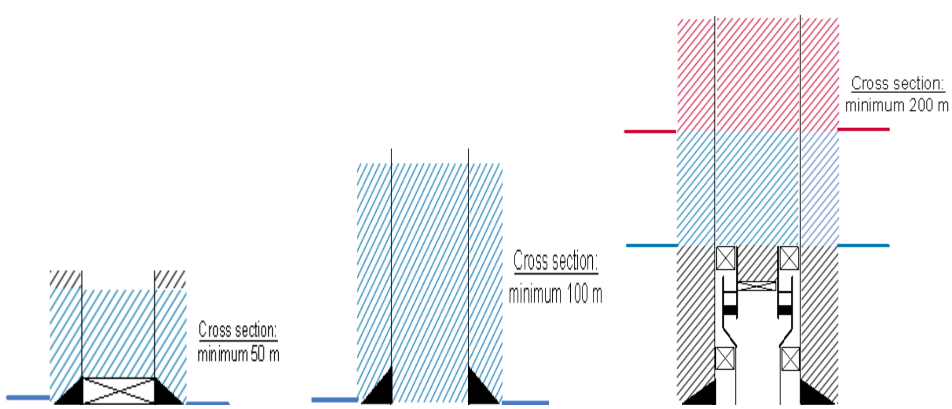


Figure 5 Primary and secondary barrier with different cement height [54]

Mechanical plugs that RLWI use for temporary plugging are not acceptable for permanent well barrier; they are only accepted as a foundation for a permanent barrier.

Barrier elements leak test criteria from Well Integrity manual

The table below show the necessary test criteria when the plug shall be used as a barrier in P&A purpose.

Table 2 Leak test requirements-Plug &abandonment [67]

Test	Barrier/barrier element	Test pressure/duration	Acceptance criteria
Low pressure leak test (all volume)	Cement plug/mechanical plug	15-20 bar/5 min	Zero. 5% deviation is accepted to account for temperature effect, air entrapment, media compressibility, but a decreasing trend – which approaches zero for minimum 5 min
High pressure leak test (all volume)	Cement plug/mechanical plug	Fracture gradient (at shoe)+ 70 bar/10 min or max differential pressure+ 70 bar/10 min. Fracture gradient + 35 bar shall be used for surface casing plug	Zero. 2% deviation is accepted to account for temperature effect, air entrapment, media compressibility, but a decreasing trend - which approaches zero for minimum 10 min - shall be documented on the test curve If possible leak paths to more than one open formation, the highest of the fracture gradient shall dictate the test pressure (e.g. if a plug is set inside a liner, the formation below the liner lap and below the plug will be possible leak paths).
Inflow test	Barrier elements that will see pressure differential from below and when a positive pressure test will not qualify the WBE to hold pressure from below e.g. shoe track	Max differential pressure-10 bar/30 min (detoriation of well fluid shall be accounted for)	Zero. Less than 3 bar/10 min deviation is accepted to account for temperature effect, air entrapment, media compressibility, but a decreasing trend - which approaches zero for minimum 10 min - shall be documented on the test curve

Removing of equipment above seabed [67]

There shall be no obstruction related to operation (drilling/well) left behind on the sea floor. In the end of a P&A operation the casing will be cut and the wellhead is to be removed. The cutting depth should be minimum 5 meter below seabed. However, for a cutting depth beyond 2 meter below seabed no remediate actions are required.

5 Units to perform Plug and Abandonment

5.1 Category A, Category B and Category C

In Statoil the traditional categorization of intervention units are [67];

- Category A: Subsea C/WO activities (well intervention) with wireline without use of a C/WO riser system to surface. Riserless Light Well Intervention (RLWI)
- Category B: Subsea C/WO activities (completion, workover or well intervention) utilizing a C/WO riser system in open sea. This implies that there is a possibility to take well returns to the vessel
- Category C: Subsea C/WO activities (completion, workover or well intervention) utilizing a C/WO riser system in combination with a drilling BOP and marine riser. This includes ability to run and retrieve well completion equipment through the marine riser system. This also includes use of high pressure riser and well control equipment inside the drilling BOP and marine riser. This implies that there is a possibility to take well returns to the vessel

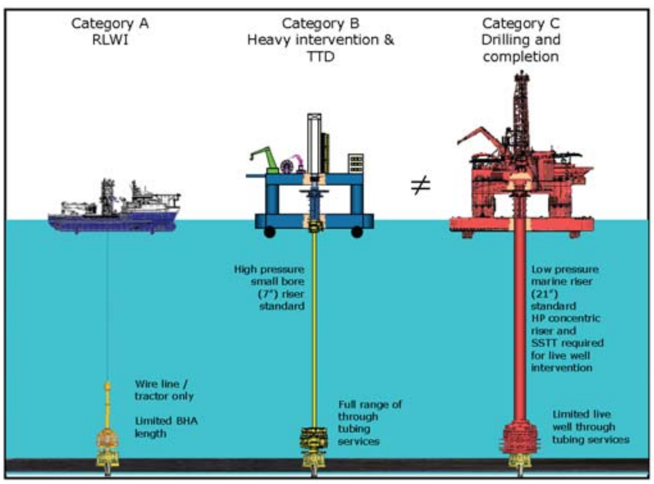


Figure 6 Illustrate the main difference regarding RLWI, heavy intervention and conventional rigs [47]

The Riserless Light Well Intervention vessel is in Category A and semi-submersible-submersible rig is in category C. A Category B rig is under construction for Statoil.

There is a limited amount of suppliers that delivers RLWI vessel services in North Sea; currently only Island Offshore and Helix Well Ops are providing this.

Present Category A vessels in operation in N.C.S:

- Island Offshore; Island Frontier, Island Wellserver and Island Constructor. Vessels use no marine riser and perform only wireline runs. However Coiled Tubing is being evaluated. Further information regarding Coiled Tubing can be found in Chapter (11).
- Helix well Ops; Seawell and Well Enhancer. Helix operates mainly on UK sector. Helix Well Ops [18] performs standard intervention with wireline without riser, but has attempted to perform Coiled Tubing operations with riser from a Light intervention vessel in a live well.

5.2 Riserless Light Well Intervention (RLWI)

5.2.1 Wireline operation from a RLWI vessel

To perform maintenance on live subsea wells a rig or a RLWI vessel (monohull) can be used. All standard wireline operation can be performed from the RLWI vessel. The concept is based on use of a subsea intervention well control package (WCP) including a lubricator with no high-pressure riser tied backed to the vessel.

Statoil, utilize two specialized and modern vessels on full year contracts (Island Frontier and Island Wellserver) and a third vessel on campaign contract (Island Constructor).

<u>Typical application for RLWI:</u>

- 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 7 The RLWI vessel is position above the well [27]

In order to obtain well control during wireline operation, a RLWI Stack is mounted on top of XMT. The RLWI stack comprises both a Well Control package and a Lubricator Section. Wireline runs are performed by deploying the bottomhole assembly(BHA) and the pressure control head (PCH) in open sea. The BHA is lowered into the lubricator and the Pressure Control Head (PCH) is locked onto the Upper Lubricator Package (ULP). The PCH hold pressure from well to avoid Hydro Carbon to the environment, by support from pressurized grease in flow tubes. Typical cables for RLWI operations are slickline, e-line cable and braided wire.

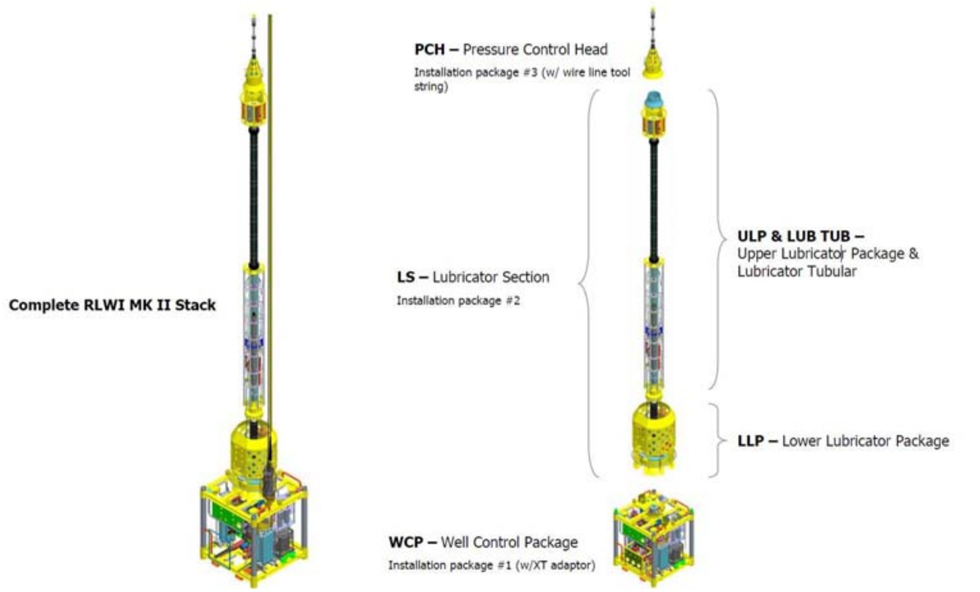


Figure 8 RLWI Stack (Well control package and Lubricator section) [14]

5.2.2 Challenges when using RLWI vessels compared with use of semi-submersible rigs

The RLWI vessels have some limitations/disadvantaged compared to a conventional rig.

1. Reaching target in the wellbores if the well is very deep and with high angle. This has greatly improved after the WL tractor was taken into use. Max pulling forces of the tractor increases due to continuing development and improving tractors and therefore the distance to Coiled Tubing and drill pipe penetration decrease.
2. Not able to pump and circulate to perform sufficient well clean up. 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 XMT.
3. Difficult to place cement barrier plug, due to no drill pipe or Coiled Tubing.
4. The weather limitation for a RLWI vessel for deploying/retrieving heavy equipment (RLWIV stack) are currently typical 4,2 m heave and during running wireline operation the limit is 6 m heave in moonpool. As a comparison, for semi-submersible rig the heave limitation for landing of XMT and Tubing Hanger (TH) is 1,5 m, and other operation limits is for a heave limitation is between 2-2,5 m. 2 m heave for a rig is around 4-6 m significant wave height. Max heave before disconnect is 8 m. (around 10-12 m significant).

Further information regarding RLWI history in Statoil can be found [App B] and Chapter [6.3].

6 Plug and Abandonment operation

In this chapter existing practice for permanent plug and abandonment operation (no sidetrack) will be described, and an overview will be given of which operation RLWI vessels have performed or where the vessels have no operational experience as of today. In the end relevant jobs experience in plug and abandonment operations are listed.

6.1 Plug and Abandonment-Existing practice

Here are the main operation steps for a P&A operation performed on a well with Vertical X-mas Tree (VXT). They will be explained more in detailed later in this chapter

1. Rig move (arrival). Mobilize subsea equipment
2. Connect to XMT
3. Kill and secure well incl. cut of tubing
4. Install tubing hanger plugs
5. Handling of subsea trees
6. Run BOP and marine riser (MR).
7. Pull Tubing Hanger and tubing
8. Run cement log
9. Plug and abandon well. Primary and Secondary barrier plug.
10. Open hole to surface plug
11. Cut and retrieve wellhead

6.1.1 Connect to XMT

The most common used rig operation for this purpose is to install a workover system on XMT to be able to kill the well after open hatch and removed tree cap. Older VXT workover system is not able to be used for the time being due to THROT is not qualified as sharable and the THROT will block the BOP shear rams. Therefore some of the temporary P&A operation is already implemented and done with RLWI vessel. For Horizontal X-mas Tree (HXT) (FMC) Statoil will normally use “add 5 WOCS”+”EDP/LRP” stack while waiting for a new workover system to be ready for operation.

6.1.2 Kill and secure well

a) Kill well by bullheading mud: Pump a fluid with plugging material into the reservoir to avoid influx into well. This can be both water and oil based mud.

b) Install a deep set mechanical plug: A mechanical plug is usually installed in the tail pipe to act as a temporary barrier and/or as fundament for cement plug.

c) Punch and cut tubing on WL. Punch hole in the tubing usually with explosives. There are explosive Cutter, Plasma Cutter, Electrical mechanical cutting tool, and Split-shot that can be used for P&A purpose. Further information about cutting devices can be found in [App G].

d) Displace tubing and A-annulus to heavy fluid (to achieve overbalance against reservoir pressure).

6.1.3 Install tubing hanger plugs

Install tubing hanger plugs in production bore and annulus to achieve minimum two barrier requirements while removing RLWI Stack and VXT. The barriers are deep set plug and tubing hanger plugs.

6.1.4 Handling of subsea trees in P&A operations

The focus in the Thesis will be how to perform P&A operations in well with VXT, since the oldest wells are VXT. There are major differences in performing P&A on wells with Horizontal X-mas tree vs Vertical X-mas tree (VXT].

Horizontal X-mas tree (HXT)/ EXHT;

The HXT is installed on top of Wellhead, before tubing and tubing hanger are installed. Main benefits for the HXT: Possible to change out the tubing without retrieving HXT in case of tubing leakage etc. Tubing hanger is inside the HXT. The HXT has no valves in the main bore. For PP&A purposes, the tubing hanger and tubing need to be retrieved before the HXT can be retrieved. Currently, the Light well intervention department in Statoil has no track record of retrieving HXT, but BP has retrieved HXT using the Island Intervention.

Vertical X-mas tree (VXT)/Conventional XT;

The tubing hanger and tubing is installed inside the Wellhead before the VXT is installed. The VXT needs to be retrieved before tubing hanger/tubing is retrieved in a P&A situation. For plug and abandonment operations the access is achieved for RLWI vessel, via the RLWI Stack, VXT, and wellhead. After the VXT has been removed, the access is through the RLWI Stack and wellhead. The Light well intervention department in Statoil has retrieved several VXTs.

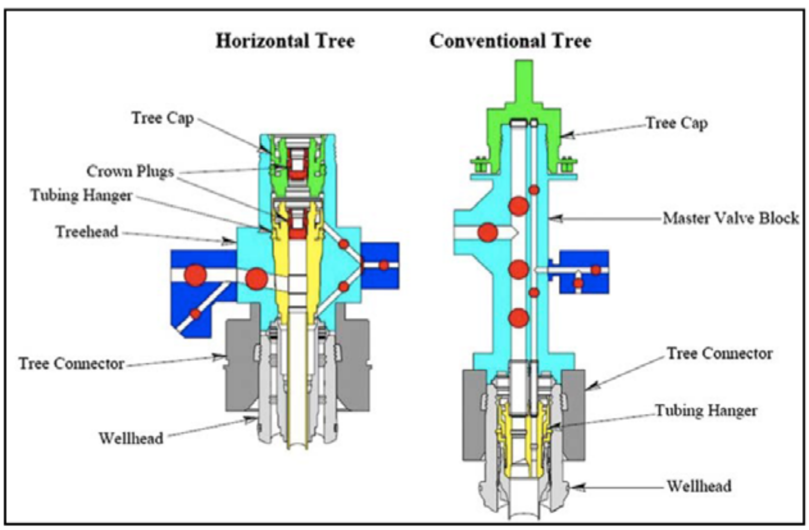


Figure 9 Schematic showing the difference between horizontal and vertical X-mas tree configuration [11]

A table is made to show the main differences of a Horizontal X-mas Tree (HXT) and Vertical X-mas Tree (VXT) in P&A operation.

Table 3 HXT vs VXT in P&A operations

	Full P&A	P&A for slot recovery
HXT	The HXT need to be pulled in the end of the P&A operation, after tubing is pulled and barriers is in place	Do not need to be retrieved during P&A for slot recovery.
VXT	The VXT need to be retrieved earlier in the P&A operation sequence. After the well is secured with two barriers, and before pulling of tubing.	The VXT need to be retrieved in the P&A operation and installed after new completion installed.

6.1.5 Run BOP and Marine Riser

Use of Blow Out Preventer (BOP) and Marine Riser (MR) are standard for semi-submersible rig operations. The BOP consists of three pipe rams, annular and shear rams that are able to cut the drillpipe and tubing. By use of BOP and MR, the P&A operation as retrieval of tubing hanger and tubing, and placement of barriers can be performed with sufficient barriers in place.

6.1.6 Pull tubing hanger and tubing

Normally the rig uses "Tubing Hanger Emergency Release Tool" (THERT) to retrieve the tubing hanger and tubing.

The tubing is screwed into the tubing hanger. In order to retrieve the tubing to surface the tubing hanger is unlocked using the Tubing hanger Emergency release tool (THERT). The THERT latches onto the profile in the tubing hanger and release it from the wellhead. The tubing is then free to be pulled to the surface using drillpipe. The pulling weight for such operations depends on well the specific well conditions; and may vary between 100 and 150 tons. Typically the length of THERT is approximately 1 m long. The shear and seal ram (SSR) in the BOP are able to cut above THERT when THERT is locked to the Tubing hanger and therefore able to obtain the barrier throughout the operation while retrieving the tubing and tubing hanger to surface.

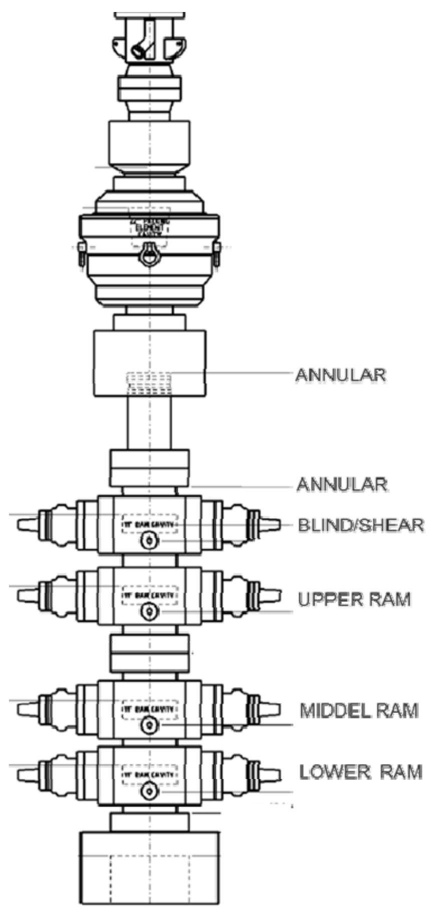


Figure 10 Blowout preventer stack [63]

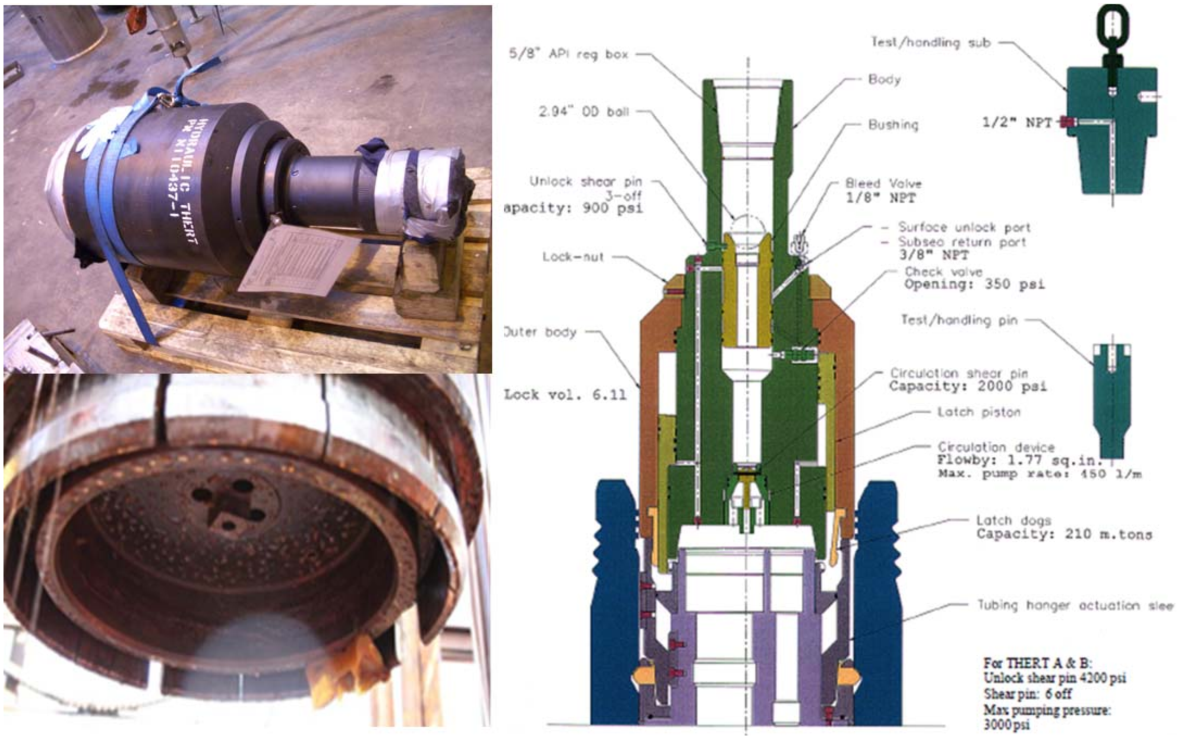


Figure 11 Pictures and overview of THERT [61]

In order to run and install the tubing and Tubing Hanger (TH) the semi-submersible rig use a tool “Tubing Hanger Running and Orientation Tool” (THROT). When running the THROT during completion the tubing hanger will be oriented correctly in place in order to match the hydraulic couplers of the VXT. It is also possible to use the THROT to retrieve TH and tubing.

6.1.7 Run cement log

Logging by wireline is performed to qualify the cement or formation as a barrier element. To check the quality and existence of cement behind the casing, Cement Bond Log (CBL) and UltraSonic Imager Tool (USIT) are run. The cement bond tools measure the bond between the casing and the cement. The measurements are performed by using acoustic and ultrasonic tool. The result is displayed on a CBL. Both an increase in the decibel attenuation or a reduction of the reading in millivolts is indications of better quality bonding of the cement to the casing. The USIT uses a single transducer mounted on an Ultrasonic Rotation Sub. The transmitter releases ultrasonic pulses between 200 and 700 kHz and measures the received ultrasonic waveforms reflected from the internal and external casing interfaces. An indication of the quality of the cement bond at the casing/cement interface is measured by observing the rate of decay of the waveforms received in the tool. Further description is given in attachment [App H].

A minimum of 50 m cumulative interval with cement is required to act as a permanent external barrier

Logging is a requirement when the same cement job defines both the primary and secondary barrier element. A combination of cement and formation barrier is also possible.

The setting depth of a cement plug is determined by the formation strength limitation. The cement plug is leak tested after installation according to requirements.

6.1.8 Establish well barriers and perform verification

A fundament for the cement plug needs to be in place before installing the cement plug. A mechanical plug is normally preferred as fundament. Alternatively a hi-viscosity pill or a cement support tool (CST) can be used as a foundation. While performing the cementing the drillpipe end is placed in the bottom of the area to be cemented. After 2/3 of the cement plug is displaced in the well, the drillpipe is retrieved above the cement plug and the pipe circulated clean. Well with high angle (>70 deg), need to simultaneously pump and pull to avoid mud contamination in cement.

If the logging result indicates insufficient cement behind casing the first choice is to use formation as barrier and the second choice is use the “Perf and wash tool”:

1. The formation bonding will be checked. If the formation is qualified by pressure testing in the field, only logging is necessary.
2. A “Perf and wash tool” can be used, see Chapter [12.4] for more information. Perforate, wash annulus, squeeze cement, drill out cement inside casing, and log the cement behind casing and in the end set a new cement plug inside casing.

   Comment: Statoil is planning to only pump cement as a standard balanced cementing operation without squeeze for some wells, then mill and log to evaluate the effect.

6.1.9 Establish open hole to surface barrier

The open hole to surface barrier is a “fail safe” barrier, where a potential source of inflow is exposed after e.g. a casing is cut. A standard operation for open hole to surface barrier is; cut and retrieve intermediate (13 3/8”) casing, install bridge plug as barrier fundament and establish cement barrier.

6.1.10 Cut and retrieve wellhead

For permanent abandonment wells wellhead and the following casing need to be removed. Semi-submersible rigs are able to do this operation, but lately several vessels have performed this operation more cost effectively. See Chapter (14) for more information regarding cut and retrieval of wellheads.

Figure 12 Wellhead removed from a well [29]

6.2 Overview over P&A operations and experience from RLWI vessel

The table below describes Statoil plug and abandonment experience with RLWI vessels on N.C.S. Operations performed in UK sectors (by other operators) are mentioned but not counted. As showed in the Table 4 some of the standard P&A operations are already performed from a RLWI vessel.

Table 4 Overview of PP&A operations and experience from RLWI vessel

Main operation steps	Experience from a RLWI vessel
Run and connect stack to XMT	Standard operation to connect with well control package with an adaptor to fit different wellhead or XMT.
Kill and secure the well including cut of tubing	Kill the well. This is down some few times. Bullhead, pump down through kill line/umbilical.
	Install a deep set plug.
	Punch and cut the tubing
	Displace tubing and annulus to heavy fluid. Done on Temporary Plug and Abandonment (TP&A) operations
Remove XMT	Done some times for a TP&A operation, while prepare the well for rig operation and when change out or repair defect XMT.
Pull tubing	Never been done from a RLWI vessel before
Establish well barriers	Done by batch operation year 2000
Establish open hole to surface barrier	Never been done from a RLWI vessel before in NCS, but performed several times for other operators UK sector.
Cut and retrieve wellhead	Never been done from a RLWI vessel before in NCS, but performed several times for other operators UK sector.
Standard procedure	
Done few times	
No experience	

6.3 RLWI experience from plug and abandonment operations

6.3.1 First attempt to perform P&A and establish cement barrier from a RLWI vessel

History

Six gas production wells were drilled and completed in the period 1986-1988 [52]. The wells were shut-in during august 1998 when the host was taken out of service. In 2000, part of the P&A was performed with a RLWI vessel. The wells are permanently plugged and abandoned with a semi-submersible rig and the template removed.

Prepare P&A with RLWI

The job conducted from RLWI vessel involved reservoir isolation, cutting production tubing and recovery of subsea trees.

Scope of work

1. Pull trash cap and HP tree cap
2. Run subsea lubricator
3. Bullhead well through tubing using seawater
4. Punch tubing above production packer
5. Bullhead annulus volume
6. Cement squeeze reservoir.
7. Install mechanical plug in tubing at production packer. Tested to 70 bars above reservoir fracture pressure.
8. Set balanced cement plug above production packer. The balanced cement plug was tagged and pressure tested to 70 bar above reservoir fracture pressure. The 4 ½" tubing and 9 5/8" casing were displaced to seawater on all wells.
9. Cut tubing above cement plug
10. Verify 100% cut
11. Pull subsea lubricator
12. Pull XMT
13. Install Wellhead Protection Cap

<u>Comment:</u>

The cementing job was performed through the wellhead control package. The cement in the reservoir disappeared into the formation. Today more ideal cement had been used for the actual reservoir.

This job was performed prior to the NORSOK Standard D-010 rev 3 2004 was implemented and qualification of the cement behind casing by logging was not required.

6.3.2 Temporary plug and abandonment operation performed by RLWI vessel

The table below show an overview over some temporary P&A jobs RLWI vessels that have been used in preparation for P&A/sidetrack operation for semi-submersible rigs in Statoil Norway.

Table 5 Preparation for P&A and sidetrack operation performed by RLWI vessel

Vessel/Year	Well	Scope of work	Summary
RLWI vessel #2 2011	Well 1-5	Prepare for P&A for semi-submersible rig [65]	Killed the well with sea water/MEG (1,055 SG). Set deep set plug in tubing tail pipe. Punched tubing and displaced the tubing and 9 5/8" casing to 1,055 SG sea water/MEG solutions. Installed and tested shallow set mechanical plugs both in tubing main bore and annulus bore. Disconnected the flow line and retrieved the x-mas trees.
RLWI vessel #1 2011	Well 6	Prepare P&A and sidetrack for semi-submersible rig [53]	Performed caliper run from liner to TH. Installed 7" mechanical plug in liner. Punched tubing above PBR. Displaced well to heavy fluid. Performed cement log in liner. Installed 7" EV0 plug w/Expro gauge system in liner
RLWI vessel #1 2011	Well 7	Prepare for P&A and semi-submersible rig [53]	Performed caliper run from liner to TH. SLB Punched tubing above PBR. Bull headed well to heavy fluid and installed 7" mechanical plug in liner. Installed 7" plug w/Expro gauge system in tailpipe.
RLWI vessel #3 2012	Well 8	Prepare for P&A and sidetrack semi-submersible rig [64].	Performed caliper run. Pumped bailer runs to recover Black Sticky Stuff (BSS). Punched and cut tubing above extenda joint. Installed straddle. Displaced tubing and annulus to heavy brine. Installed THCP w/pump open plug. Installed annulus plug. Cut umbilical clamp and disconnected flowline and umbilical, pulled VXT.
RLWI vessel #1 2013	Well 9	Prepare for P&A and sidetrack [50]	Run DHSV lock open tool. Performed caliper run. Installed deep set plug in liner and installed plug in tailpipe. Run kill hose. Displaced well to kill fluid. Installed THCP.

7 Technology Challenges

The table below shows an overview of technology challenges in plug and abandonment for RLWI vessel and semi-submersible rigs. The relevant challenges for the units are marked with X. More detailed information regarding technology challenges will be given in the next chapters

Table 6 Technology Challenges in plug and abandonment

Technology Challenges		**RLWI vessel**	**Semi-submersible. Rig**	**Chapter**
Logging Challenges in P&A operation	Cement bond logging through multiple casing strings	X	X	[8.1]
	Log cement behind casing with tubing partly retrieved	X	N/A	[8.2]
	Identify control lines behind tubing	X	X	[8.3]
Cutting of tubing and control lines		X	X	[9]
Different approaches for removing tubing		X		[10]
Coiled Tubing operation without riser		X		[11]
Different approaches for installation of barriers		X		[12]

Is it necessary to cut and retrieve tubing? Not always. This depends on whether there are control lines behind tubing and/or wells where the outer barrier element, i.e. the casing cement, is either not verified, not present or in poor condition.

8 Logging challenges in P&A operations

This chapter describes logging equipment, challenges and status that exist for P&A operations as logging through multiple casing strings, log cement behind casing with tubing partly retrieved and identifications of control lines behind the tubing.

8.1 Cement bond logging through multiple casing strings

During construction of a well it is not always required to log the cement after a successfully job is performed. However, due to the requirements of verified and qualified cement for plug and abandonment purpose the “shortcut” described above can result in a later challenge. Today it is only possible to log through one tubular, hence todays practice is to pull tubing and casing to log the relevant cement. If cement was logged and verified during the initial drilling, this will normally be used as qualification for the casing-cement. Logging of the cement is always required if the same casing cement is used as both primary and secondary barriers [67].

According to UK regulations; If ”good cement job” during initial drilling, the casing cement is considered qualified (”competent”). This is presently not according to Norwegian regulations. In Norway it is generally more common to perform logging after each cement job. For exploration wells this is also a mandatory step

There is no logging tool or associated processing method available in the marked that are able to qualify cement behind multiple casing (normally 13 3/8” casing cement through a 9 5/8” casing).

8.1.1 The big picture regarding logging tools and log response

Cement Bond Log (CBL) and Variable Density Log (VDL)

-CBL uses the variations in amplitude of an acoustic signal traveling down the casing wall between a transmitter and receiver to determine the quality of cement bond on the casing wall. The acoustic signal will be more attenuated in the presence of cement than if the casing were un-cemented.

-VDL is a presentation of the acoustic waveform at a receiver of a sonic or ultrasonic measurement. The amplitude is presented in color or the shades of a gray scale. The variable-density log is commonly used as an adjunct to the cement-bond log, and offers better insights into its interpretation.

CBL – VDL is taking in to account the amplitude of the first arrival on the recorded waveform at a given depth. No azimuthal or radial information can be extracted from recorded waveforms.

-CBL and VDL logs are acquired with a sonic logging tool that has a monopole transducer and monopole receivers placed respectively at 3 ft and 5 ft from the transmitter (see figure above). The monopole sonic transmitter sends a low frequency (10-20 kHz) pulse that induces a longitudinal vibration of the casing. The average values of the circumference of the casing are represented in the data record. The data contain the amplitude of the full waveform

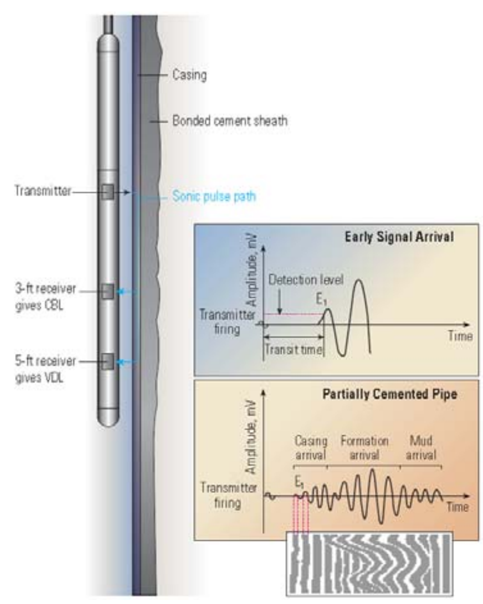


Figure 13 Cement bond log (CBL) [12]

received at 5 ft and the first positive peak (E1) of the sonic waveform received 3 ft. When the casing is bonded to a stiff material, the vibration of the casing is attenuated and the CBL E1 amplitude is small.

Ultrasonic log

Ultrasound Logging is extracting caliper values from the time of first arrival of reflected signal, casing thickness from the casing resonance frequency and cement bond to casing from spectral decay.

The ultrasonic azimuthal bond log uses a high frequency pulse echo technique. The tool uses a rotating 7,5-rps transducer with emits a broadband ultrasonic wave upright to the casing wall, to provoke the casing into resonance mode. The ultrasonic wave frequency is adjusted between 250 and 700 kHz depending of the casing thickness and the amplitude decay.

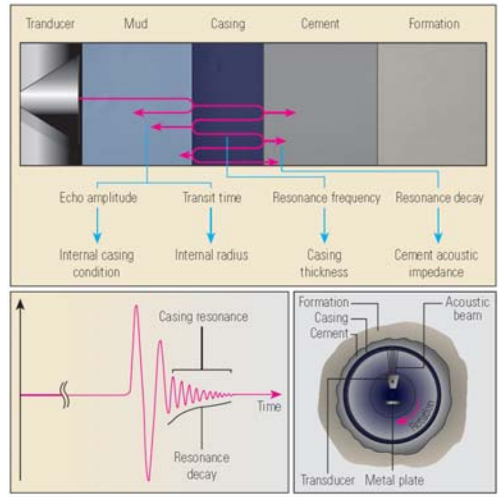


Figure 14 Principle of the pulse echo acoustic impedance measurement [12]

The main shortcomings of the ultrasonic log compared with the CBL/VDL log include:

- Limitation when operating with dense wellbore fluid that heavily weakens the ultrasonic signal.
- Difficulty in the presence of a dry micro –annulus
- The VDL differ between a fluid filled annulus and cement in the presence of a large-micro annulus.

The main shortcoming of the CBL/VDL log compared to ultrasonic log:

- Affected by outer casing
- Affected by mud type and density
- Very sensitive to centralization and micrometric micro-annuli
- Does not allow for differentiation between channeling, micro annuli and or contaminated cement

Isolation Scanner [38]:

An Isolation Scanner is used for cement evaluation. Isolation Scanner combines a new ultrasonic technique with a conventional pulse-echo technology-flexural wave imaging. This system is used to evaluate all kinds of slurries and cement. This new method provides real-time evaluation of cement jobs in a wider range of conditions than previously available with conventional technologies.

Borehole Acoustic Reflection Survey (BARS) [39]

Borehole Acoustic Reflection Survey uses acoustic energy reflected by the in-homogeneities in the formation the BARS is able to create a high-resolution image of the formation surrounding the borehole. Open hole surveys has been performed using the Sonic Scanner™ tool, which has 3 monopole transmitters and 13 receiver stations (with different azimuts), total 104 receivers. Using all monopole sources, the tool provides 312 waveforms at each depth position. Transmitted energy is reflected at the interfaces and recorded at the receivers. The BARS technique produces acoustic images with 2-3 orders of magnitude higher resolution (and accordingly smaller range) compared to borehole seismic images. Potential applications for BARS are well placement relative to formation topography, reservoir structural analysis and characterization. This technique with high-resolution images may also help to identifying sub-seismic inter beds, faults or fractures around the well.

8.1.2 Status regarding cement bond logging through multiple casing strings

Presently, there are no tools commercially available offering sufficient accuracy and repeatability of the result when logging through multiple casing. There are several companies working the challenge. Existing technologies are being improved and also new technology is built in attempt to solve the challenge.

It is widely agreed that cement and well integrity logging must obey the principles of acoustic. It is believed that by adding energy in displacing the particles in the media then more information's from deeper reflectors it possible to achieve. Unfortunately, as of today they are not able to de-convolute borehole modes from recorded signals with enough precision in order to increase our statistical margins. It is major challenge and much work is performed in order to increase understanding of the phenomena trough 2D and 3D viscoelastic acoustic wave field modeling.

Due to confidentially no more information on the subject was possible to include in this Thesis.

8.2 Log cement behind casing with tubing partly retrieved

In order to perform P&A operation from a RLWI vessel without Coiled Tubing installed, one possibility would be to cut tubing, lift tubing up necessary meters, then log the cement behind the casing (in the section where the tubing is removed) and then use the cut tubing to place the cement before retrieving the tubing to surface.

According to Schlumberger it may be possible to log the cement behind a 9 5/8"casing after the bottom hole assembly has been deployed through the 5,5 tubing, but Schlumberger recommend to only use USIT/Isolation Scanner without using Sonic CBL, due to the possibility to centralize. There is no available centralizers and sonic tool design which could fit into tubing and maintain good centralization in casing afterwards. It is preferred to log in Brine.

8.2.1 Comments regarding log cement behind casing with tubing partly retrieved

Another method (but not recommended from Schlumberger) is to log SSL (Slim Sonics) eccentric using standoff if the well is deviated in the area of logging.

CBL uses the variations in amplitude of an acoustic signal traveling down the casing wall between a transmitter and receiver to determine the quality of cement bond on the casing wall [71]. The amplitude of the E1 peak is directly depended of the presence of the bonded material to the pipe. The signal is generated by a monopole source with central peak in range of 10 to 20 kHz and subsequently the wave front is evenly distributed inside the borehole and towards the face of the pipe. There is no directionality inside the transmitted signal from the source and the receiver's stations are not segregated. In other words tools will record total amplitude of the received signal travelling inside the borehole. One can understand that the position of the tool in the borehole is not critical because receivers will record total wave field strength and not segmented signal. Running borehole compensated mode will ease the signal processing, but the tool shall not be run slick as direct arrivals will be computed as road noise by the DFAD algorithms and thresholds see figure (13). An exception needs to be in place to perform non centralized CBL logging.

8.3 Identify control lines behind the tubing

8.3.1 Challenges with control lines

According to requirement from NORSK D-10:

Control cables and lines shall be removed from areas where permanent well barriers are installed, since they may create vertical leak paths through the well barrier.

In order to create a barrier with cement over the entire cross section one possibility is to install a mechanical plug and punch the tubing two places and then squeeze the cement into the annulus.

However, in wells with deep pressure gauges and sliding sleeves, there are also electric, fibre and hydraulic control lines.

These lines may have the potential to create micro annuli and thereby leak paths.

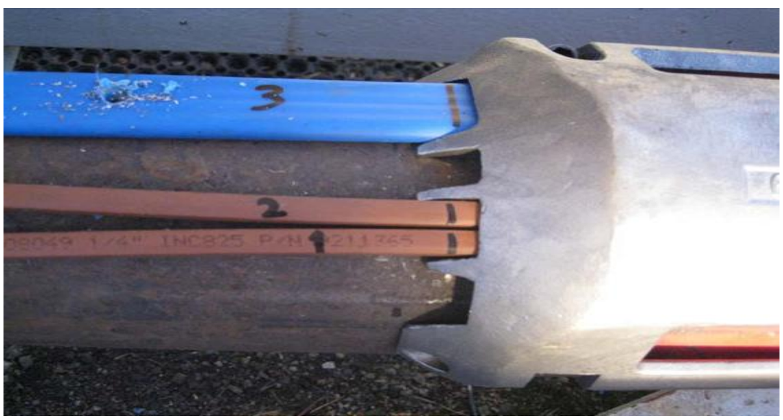


Figure 15 Control lines clamped to tubing [72]

8.3.2 How to identify the control lines

There are electrical and hydraulic lines in wells with Downhole Pressure Gauges or SMART Wells. The SMART wells contribute to have enormous production optimizing due to operation of sliding sleeves (to open/close reservoir zones) and SMART wells is believed to expand in future, with even more sophisticated well to be designed. For PP&A purposes both tubing and control lines need to be cut. During completion phase, the tubing is often set in compression, the lines need therefore to be detected and cut first; otherwise the cutting blade can get stuck. Further information regarding cutting operation can be found in Chapter [9].

Two possibilities to detect the control lines:

1. Ultrasonic logging tool
2. X-ray

8.3.3 Ultrasonic logging tool

Archer offers an Ultrasonic logging tool which they call SPACE™. This tool provides visual images of conditions both inside and outside the wellbore. Using high –definition ultrasound, the tool provides real-time imagery at surface in 3D of conditions inside and outside the wellbore [4].

SPACE/20™.Visualising the well in 3D – detailed investigation of conditions, assemblies and components

SPACE/20M™.Measuring the well in 3D – adding sub-millimetre accurate measurements in three dimensions

Archer has proved that the system is working for detection of high precision measurements in all three dimensions. One example [5] is a successful job Archer did for Statoil where a Downhole Safety valve (DHSV) had to be pulled in order to allow a deep set plug to be placed in the lower completion. The wireline crew was not able to latch onto the DHSV with the pulling tool. After running SPACE tool a modified pulling tool based on exact measurements was made, and the modified tool successfully removed the DHSV on the first attempt.

Archer is currently working on the second generation of the SPACE tool. In addition to be able to be configured to look along the wellbore or sideways, one is aiming to also identify clamps mounted on tubing with this tool.

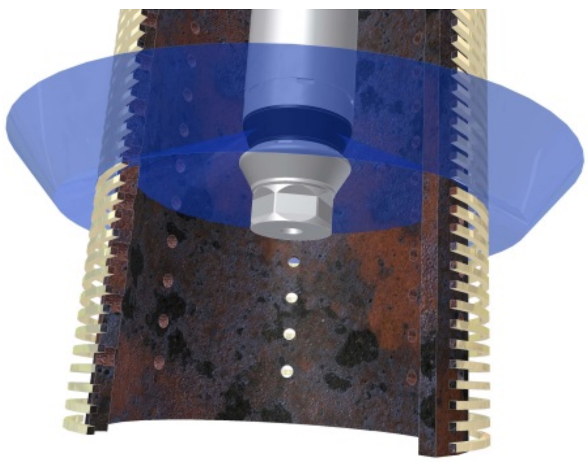


Figure 16 Illustration of SPACE logging [3]

A logging test with the SPACE tool was performed in an attempt to detect the control line/clamp and determine the orientation of the clamp. The clamp was mounted on a 7” water filled tubing and installed in a large barrel [4].

1. Clamp mounted on tubing 2. Clamp for control lines 3. Log result. Possible to see the clamp

Figure 17 Clamp and log result from test [7]

The highlighted red areas in the picture 2 (Clamp for control lines) can be recognized in the SPACE scans picture 3 (Log result. Possible to see the clamp).

The bands/steel pieces keeping the upper and lower clamps are also clearly seen. The latter are separated by 355 mm according to the software measurement. True distance is ~350 mm.

Hence it is possible to perform the following steps using the separate SPACE scans:

1. Recognize where the 7 " tubing clamp was mounted
2. The orientation of the clamp
3. The control line was not recognized in the scans. But based on clamp geometry it should be possible to give an estimate of the control lines location.

8.3.4 X-ray

Another alternative to current logging technology is using X-ray logging. Based on X-ray technology the tool is capable of producing highly detailed visual and geometric representations of well, casings, screens, valves and general cased hole instrumentation in real-time. Images are produced independent of the fluid content or flow-status of the well. Tools can be run on wireline and correlation done with GR and CCL.

If this technology can be used to identify control lines behind tubing, this can aid cutting of control lines through tubing.

8.3.5 Comments regarding identification of control lines

For the time being only ultrasonic logging has been verified to identify control line clamps to know where the control lines are. If the clamps are lost during installation of completion, it is challenge to identify control lines. However, in the future it might be possible detect the control line with using logging mechanism such as X-ray logging.

9 Technology for cutting of tubing and control lines

There are several types of cutting device that can be used for P&A purposes using wireline. These include explosive Cutter, Plasma Cutter, Electrical mechanical cutting tool, and Split-shot. See appendix [App G] for more details regarding cutting device. All cutters can be run from RLWI vessels on e-line mono cable and there is no need for tractor to cut the tubing.

In this Chapter different technologies will be described in proposing solutions to the tubing/control lines challenges.

9.1 How to cut tubing and control lines simultaneously

9.1.1 Baker Hughes mechanical power cutter

In wells with control lines, it is important to cut both tubing and control lines prior to retrieving the tubing, because it is not possible to control where the control line outside the tubing will break. The lines outside tubing can make unnecessary debris in the well, which can cause an extensive and expensive fishing operation to retrieve the control lines. Baker Hughes has designed a mechanical pipe cutter (MPC) that is currently being verification to handle such challenges.

MPC delivers precise downhole pipe cutting without damaging external tubular. Cutting penetration is continuously measured and controlled, confirming the cut has been made and avoiding damage to external tubular or control lines. For P&A purposes Baker is challenged to verify if the MPC can cut both tubing and control lines simultaneously.

Prior to cutting the tubing it is necessary to perform a logging run with the SPACE tool in order to identify the clamps that are connected to the tubing.

The idea is to cut a half moon first (on the control line side) and then program the MPC to cut the whole tubing. This is important when production packer is set in compression, due to if the whole tubing is cut at once it might be a problem to cut the cables as the cutting blade is likely to get stuck. In order to avoid doing this, Baker Hughes needs to know the position of the control lines prior to the operation. The cut have to be made close to the control lines clamp. Further information about the MPC tool can be found as part of Electrical Mechanical Cutting tool [App G].

Figure 18 Mechanical Pipe Cutter [8]

9.1.2 7 inch Downhole Electric Cutting Tool

The electric cutting tool from Welltec/Westerton is able to cut pipe size between 4,9” and up to max 7” OD. The tool is able to cut the whole tubing, but also able to cut only a certain number of degrees from zero. In combination with the Archer space tool for identification of control line clamp and the orientation sub included in the BHA it is possible to cut the tubing and control lines in one go. The tool has an OD of 4 ¼”. In order to prevent the cutting blade to get permanently stuck, the blades have been equipped with weakened points. Today it is possible to cut 15 mm outside a 5 ½” tubing. Sub for no-go is planned connected to BHA. Further improvement and testing for optimizing of the tool is planned.

Figure 19 Picture of 7 inch downhole electric cutting tool [76]

Figure 20 Picture of cutting blade [76]

9.2 Remove only necessary length of control lines

One option could be to retrieve necessary length of control lines to achieve full cross section with cement barrier. Statoil Research and Development department has an ongoing project to look into removing only necessary control length to achieve full cross section. The operation shall be possible to performed using Wireline.

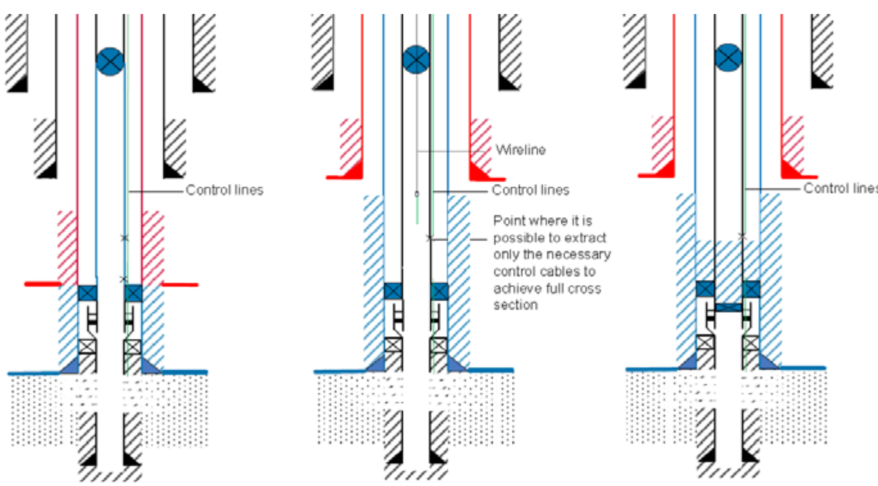


Figure 21 Remove only necessary control line length

9.3 Retrieve tubing, break and isolate control lines

An opportunity that might be possible with control lines outside the tubing is to cut and pull tubing. With no cutting sub installed it is not possible to control where the control line outside the tubing will break. The lines outside tubing can make unnecessary debris in the well, which can cause an extensive and expensive fishing operation to retrieve the control lines. An alternative could be to push down and install a mechanical plug with full bore funnel which collects the cut control lines and push them downwards. The plug can also work as foundation for cement barrier. Due to the stiffness of the control lines a stroker or power full tractor will be necessary for the operation.

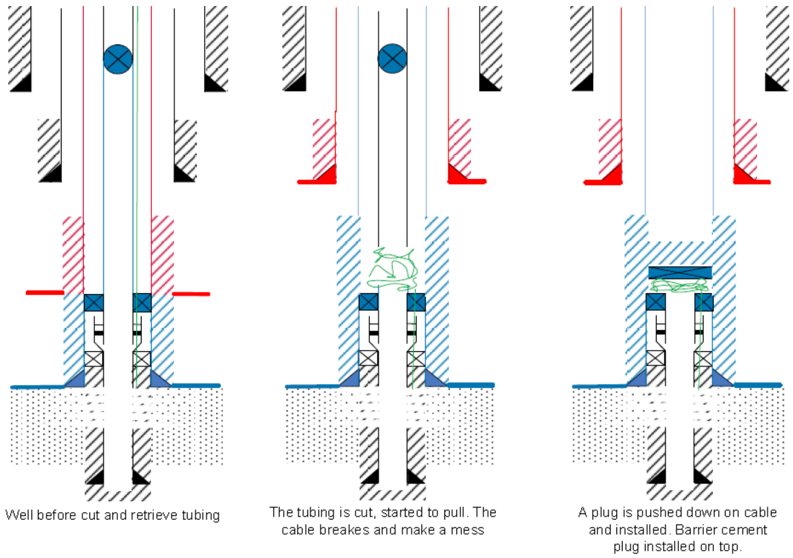


Figure 22 Cut and retrieve tubing, break and isolate control lines

9.4 Spiral cutting of the tubing and control lines

An out-of-the-box idea might be to evaluating to cut the tubing as a Helix (spiral). This could be solved by program an abrasive cutting device to cut in a spiral form; Coiled Tubing is needed on the RLWI vessel to perform the operation. By cutting the tubing with abrasive the control lines are able to be cut without the cutting blade get stuck due to compression. No need for control line detection as long as the control lines are connected in the clamps. It is recommended is to install a straddle across the cut to isolate the upper part of the cut area in order to get a sufficient squeeze of the cement. Due to the required length of the cut area, a straddle (Lego) can be installed across the necessary length [16]. It is also possible to install the cement with cement stinger and packer for cement placement.

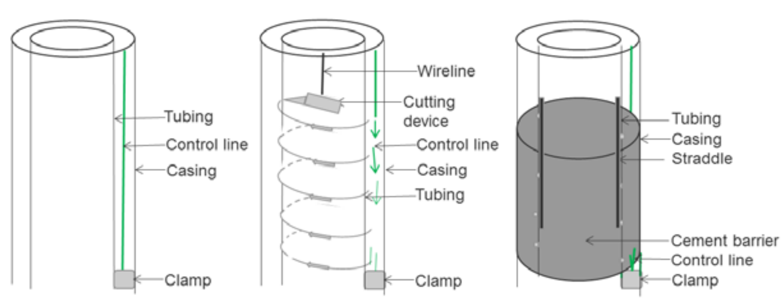


Figure 23 Spiral cutting of the tubing and control lines

9.5 In situ control lined

ConocoPhillips is developing a system called “In Situ Control Line Severing”. The system is designed for production tubing with control lined in well and with cemented casing. The purpose is to reduce the possibility for leak path via the control lines. The idea is to cuts four cut per interval with a cut radius of 110 degree of each cut. This will cover the whole radius with some overlap. The operation can be performed with wireline. A cement stinger and Packer will be used for cement placement.

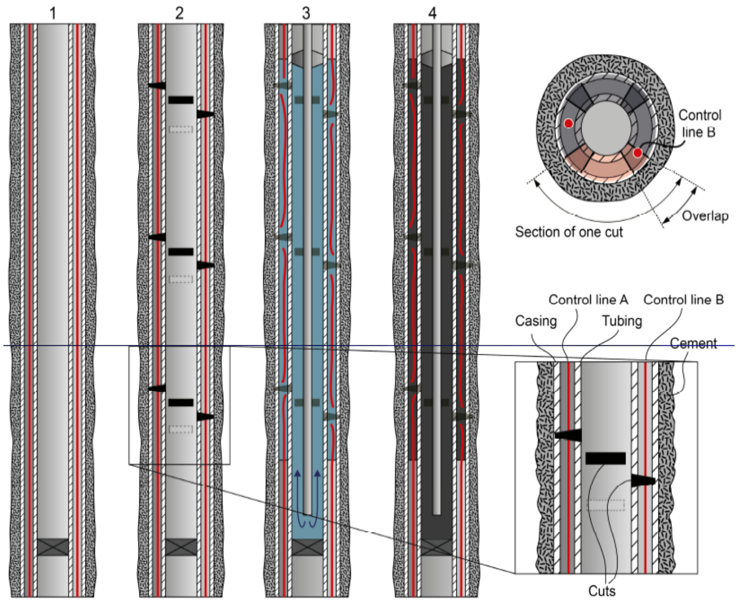


Figure 24 In Situ Control Line Severing

9.6 Cutting sub for control lines

All suppliers of SMART wells have developed a kind of cut sub device for control lines. When the tubing is cut and the pull is initiated there are knives in the cut sub that cut the control lines. Unfortunately, this is not commonly used as part of the completion on the N.C.S.

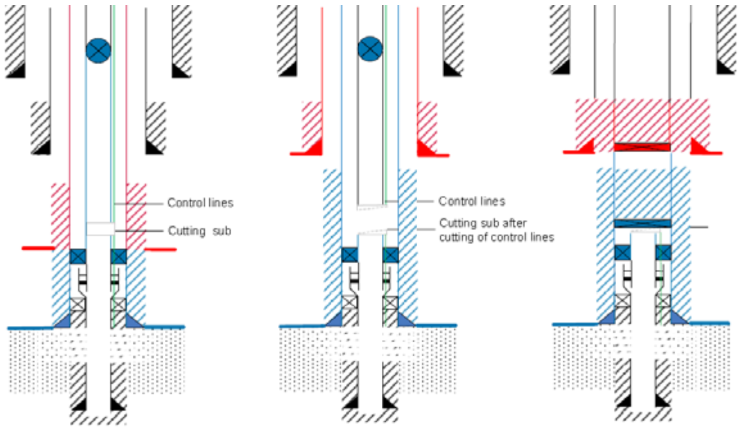


Figure 25 Cutting sub for control lines

9.7 Comments about the methods

Different technologies to solve the tubing and control lines challenges have been identified and described in Chapter (9) above. The table show a comparison of the advantages and dis-advantages for the different alternatives.

Table 7 Different methods to solve the tubing and control lines issues

Method	Advantages	Dis-advantages
Mechanical power cutter (MPC)-Baker Hughes	The cutter is -field proven, but further testing need to be performed to cut tubing and control lines simultaneously. -continuously measure and controlled during cutting.	Not able to control the angle of the cut. Not able to cut in compression. Need to retrieve the tubing to establish barrier.
Mechanical cutter- Welltec	The cutter is: -field proven, but further testing need to be performed to cut tubing and control lines simultaneously. - able to cut 7" tubing - is able to cut the desired radial degrees. Reduce the possibility to get stuck. -able to cut in compression There is weak point in cutting blades for stuck situations	The cutter: -is not able to cut outside tubing in compression. -need to retrieve the tubing to surface to establish barrier.
Remove only necessary length of control lines	Do not need to retrieve tubing to surface. Able to retrieve the piece of control line with wireline Able to establish barrier without retrieving the tubing to surface.	Not field proven Weakening the tubing.
Retrieve, break and isolate control lines	Cut with standard cutting device.	Do not know where the control line breaks. The control lines are stiff; need extremely power to push the control lines down. Need to retrieve the tubing to surface to establish barrier.
Spiral cutting of the tubing and control lines with abrasive and coiled tubing	Able to cut in compression Able to isolate the Helix cut with straddle or patch Based on the speed and sand content the helix opening should be sufficient to squeeze cement through Able to establish barrier without retrieving the tubing to surface.	Not field proven Need coiled tubing
In situ control line	There are cutting device in the market that are able to cut only necessary degrees(e.g. 0-110^{o}) Able to establish barrier without retrieving the tubing to surface.	Not field proven.
Cutting sub for control lines	Field proven Know where the tubing and control line is cut	Too late for old wells. The cutting sub need to be installed during completions Need to retrieve the tubing to surface to establish barrier.

10 Different approaches for removing tubing

The reason for retrieving the tubing in a P&A operation is the requirement expelled “Permanent well barrier shall extend across the full cross section of the well” .Similar reason for retrieving tubing can be in a P&A context: need to fix annular cement, logging behind casing or removal due to control lines.

During the whole P&A operation the main focus will be to have a minimum of two barriers in place to have sufficient well control, this is no exception while pulling or removing tubing.

In Chapter 10 different approaches for removing tubing will be described. First a suggestion where the focus is which subsea equipment is necessary to be used to achieve sufficient barriers during retrieving of tubing to surface and later in this Chapter different suggestion of removing tubing in well. Standard RLWI stack is foreseen to be used and therefore not described. Finally, the methods have been compared and advantages and dis-advantages for each method have been identified.

10.1 Technical solutions and new technologies to retrieve tubing and establish barriers with RLWI vessel

Today no RLWI vessels in N.C.S have retrieved tubing to surface. The main challenges regarding retrieving tubing are sufficient barriers during operation, volume control, pipe handling, and operating capacity. Island Offshore in cooperation with NCA/Oceaneering have made a feasibility study regarding performing P&A from a RLWI Vessel for Statoil [27], this study is the basis of this Chapter [10.1], but additional information is added.

10.1.1 Operating capacities and limitations

One RLWI vessel, Island Wellserver, was evaluated for operation constraints in the Thesis.

Main Winch on Island Wellserver has a capacity of 200 mT pull on the main-hook with double fall. The jack mechanism has a pulling capacity of 250 mT.

Deck space: The deck space will be filled up during a P&A operation. A Mezzanine-deck can be added to the vessel in order to have enough space available.

Tubing pulling capacity: Max 4000 meter of 5 1/2” completion, max 3300 meter of 7” completion.
Wells with HXT has normally 7 “tubing and wells with VXT has 5 ½” tubing

There is sufficient fluid capacity to complete a P&A job (288 m3 with a fluid density of 2,8 s.g.). The weather limitation is the same as for standard LWI operations.

10.1.2 Additional equipment needed compared with a standard RLWI operation

To be able to have full control over the well barriers during retrieving of tubing to surface, the suggestion was to use a Subsea Shutoff Device (SSD), Volume control system, and a jack mechanism To build these items for a P&A purpose for a RLWI vessel; the design should be optimized regarding weight, length and stability. A Tubing Hanger Running and Orientation Tool (THROT) will be connected to the tubing hanger while the main winch retrieves the tubing hanger and tubing to surface. A pipe handling system will be installed on deck. More information regarding these equipment’s will be described in the next sub Chapters.

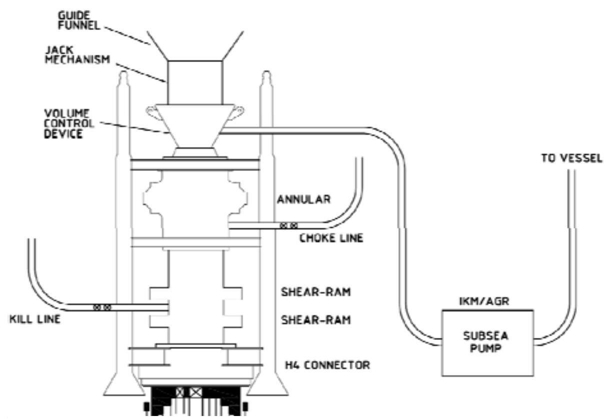


Figure 26 Subsea rig up during pulling of tubing [27]

As shown in the rig up drawing: the SSD in mounted on top of the wellhead, followed by the volume control system and Jack mechanism.

10.1.3 Subsea Shutoff Device

A Subsea Shutoff Device (SSD) device is designed to meet the requirements to be able to shear, seal and control the well in the event of an incident without requiring the use of a standard drilling BOP.

At the top of the SSD stack there is a wellhead connector profile which would enable other equipment to be connected to the top of the stack, such as a blanking cap or subsea equipment like volume control system.

The benefit by using a Subsea Shutoff Device (SSD) together with volume control, Jack, and THROT make it possible to enable the 5” x 2” tubing hanger to be unseated and the tubing to be retrieved to surface with barriers in place. The equipment required to plug and abandonment the subsea wells are either existent or of standard oilfield form such that no new technology need to be developed. Standard RLWI stack is not suitable to handle tubing retrieval.

Island Offshore propose a Subsea Shutoff stack as follows (from bottom):

- 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 27 Subsea Shutoff Device [46]

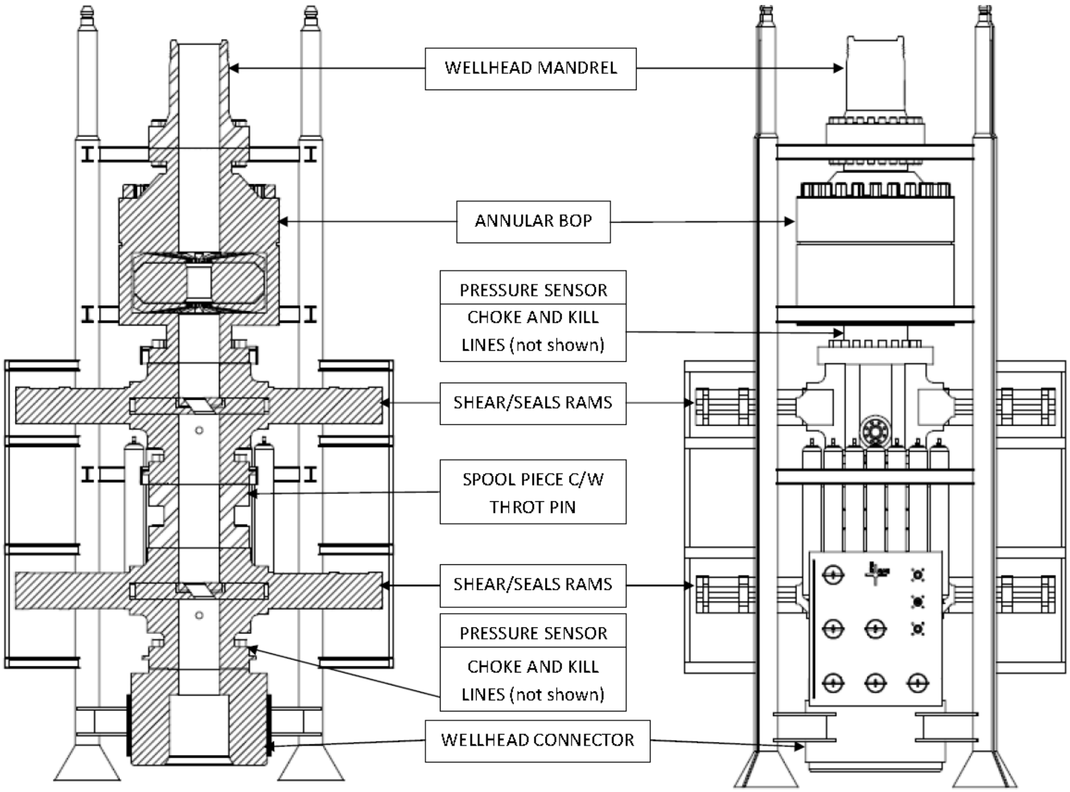


Figure 28 Illustration of a standard SSD [27]

10.1.4 Volume Control System

When planning for permanent plug and abandonment of wells from a RLWI vessel, a Riserless Mud Recovery system (AGR) or a simplified system for Mud recovery without Riser (IKM Cleandrill) may be utilized for volume control. Both companies supply such systems for top-hole drilling. The system contains pumps and level controls. The system is equipped with sensors for level control with alarms system, light and camera on top of the funnel for continuous surveillance of the fluid level. It becomes easy to discover if the well is gaining or loosing fluids.

The volume control system will be installed subsea between SSD and Jack mechanism.

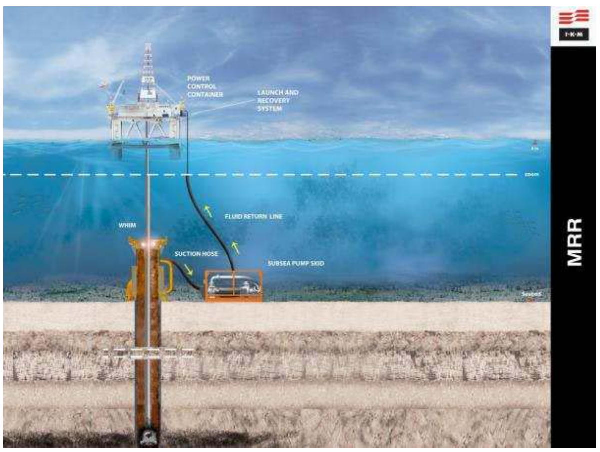


Figure 29 Mud recovery system without riser [27]

The subsea pump skid uses 2 centrifugal pumps operating in series, driven by HV variable frequency electric motors. The Mud Recovery without Riser (MRR) system includes an integrated Launch and Recovery system (LARS) for deploying of the subsea pump module and the 6" mud return hose. The system will probably be simplified for use in P&A operation.

Table 8 Equipment to be provided by supplier

ITEM	EQUIPMENT
1	Subsea Pump Module
2	Subsea Pump Module (spare)
3	Power /Control Container
4	Launch and recovery system c/w 500 m umbilical
5	Hose reel c/w 500 m lay flat hose
6	Standard spares/tooling package

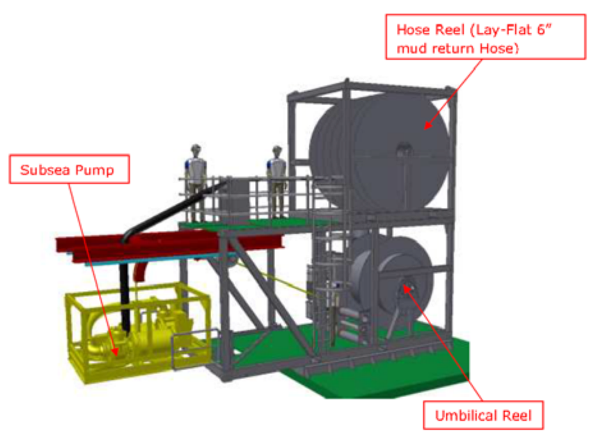


Figure 30 IKM's integrated LARS [23]

Below is an overview over how to achieve volume control during retrieving of tubing

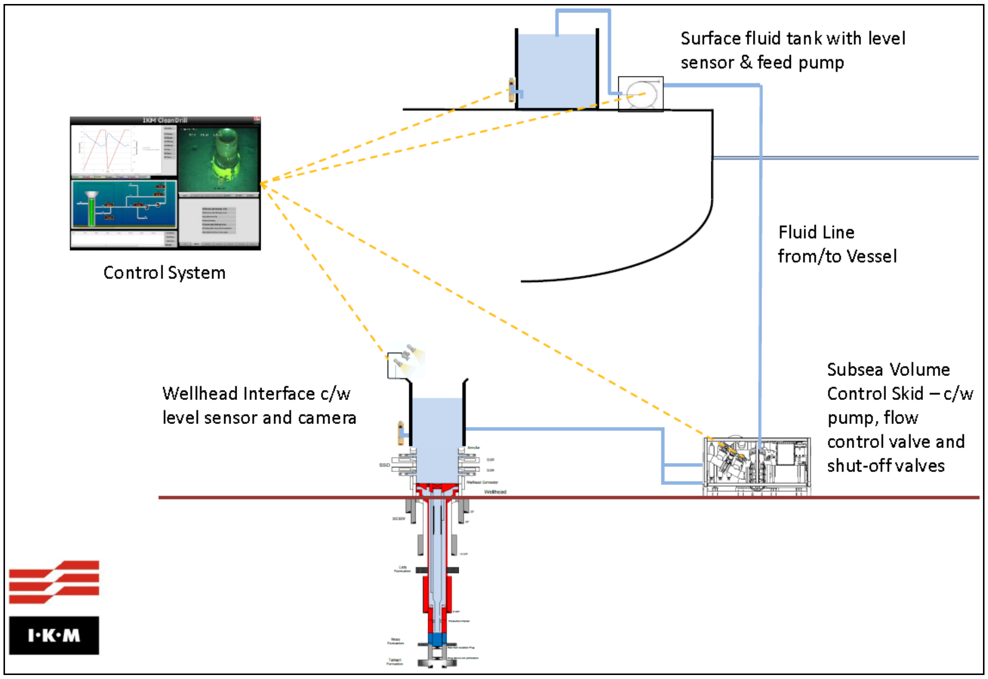


Figure 31 Main components for volume control during vessel based PP&A [23].

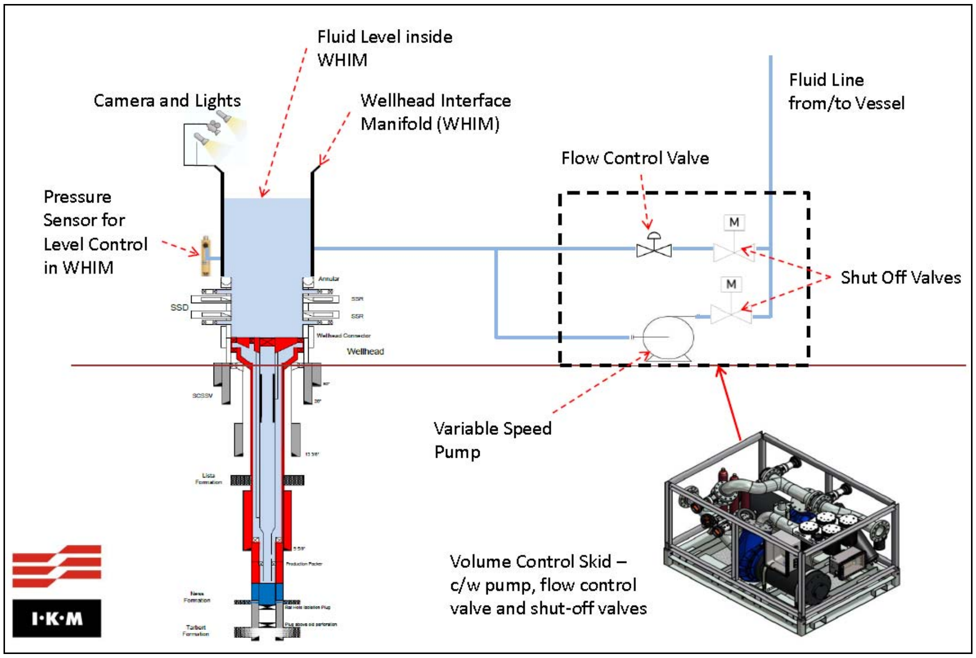


Figure 32 Volume Control Skid [23].

10.1.5 Unseat tubing hanger with Jack mechanism

A subsea Jack mechanism can assists in releasing the tubing-hanger by adding additional pulling-forces to retrieve tubing and tubing hanger to surface. By use a Jack device the centralization will be taken care of during releasing sequence. The unit can be installed on top of the volume control system and Subsea shut of device. The jacking system can lift the completion string and unseat the tubing hanger by approximately 150 mm, with a pull capacity of 250 mT then allow pulling of the tubing hanger and tubing to surface.

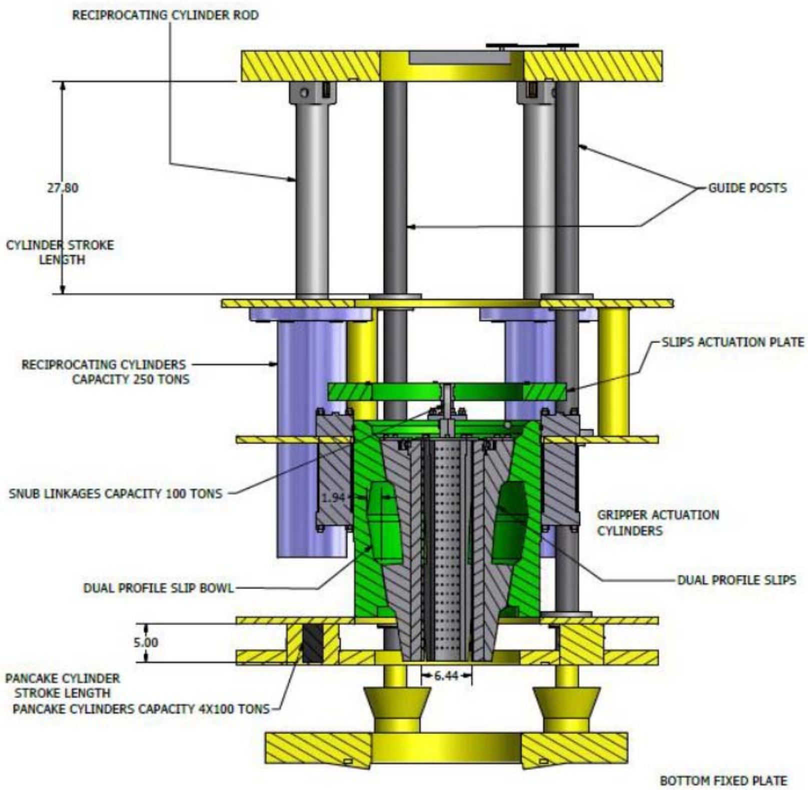


Figure 33 Geoprober Gripper assembly [27]

10.1.6 Tubing Hanger Running and Orientation Tool

The study included use of THROT to connect, unlock and retrieve tubing hanger and tubing to surface with. This THROT is usually used to run and set the tubing, while the THERT is normally used for retrieving tubing hanger and tubing to surface. The reason to choose THROT instead of THERT is due to the orientation system, and to get access to production and annulus bore for access to run wireline in well.

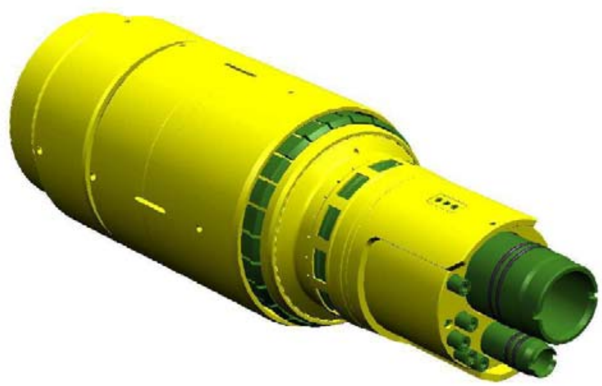


Figure 34 2” annulus bore and 5” tubing bore in THROT [27]

Figure 35 Standard THROT assembly [61]

It is possible to retrieve tubing hanger with THROT, but this is not normal procedure due to the risk of damaging hydraulic couplers, THERT is the preferred retrieving device for rig to retrieve tubing. Tubing has only been pulled with THROT under extra ordinary circumstances. In 2013 a new version of THROT will be introduced to the market. This new THROT will be shearable.

The standard THROT assembly is around 8 m long, and includes a TH Running Tool, orientations sleeve, slick joint and a stress joint. The THROT has a 2” annulus bore and 5” tubing bore.

For the RLWI operation the THROT will be run on the main winch and the orienting will occurs with support of a guiding pin in the Subsea Shutoff Device.

It is possible to retrieve the tubing hanger free with the main winch. Max pull that is possible to achieve with the main winch is 200 ton. If extra pull forces is necessary it is possible to unseat the tubing hanger with the Jack mechanism. It can be dangerous to release tubing hanger/tubing in a combination of Jack and main winch, due to the energy released when tubing hanger unseated.

10.1.7 Hydraulic power unit Subsea

In order to be able to operate all the equipment subsea (SSD, Volume control Jack), hydraulic power need to be in place. The subsea Hydraulic Power Unit (HPU) will consist of tanks, accumulators, pilot valves, and pumps. A hydraulic jumper umbilical will link the Subsea Shutoff device stack and the subsea HPU together. An electrical umbilical will provide power and communication to the subsea HPU. The electrical umbilical can disconnect in an emergency. On the vessel an electrical supply container with control equipment and panel will be mounted.

10.1.8 Pipe handling system

Island Offshore (IO) experience with pipe handling system

To handle the tubing onboard the vessel, a pipe handling system can be used. Island Offshore has a pipe handling system that they have used for trenching. Trenching is performed by running jointed drill-pipe to the seabed, and water is pumped at a high rate through the drill-pipe and through a nozzle-arrangement at the end of the drill-pipe. The water made a trench in the seabed, one will achieve a trench for lying of pipe-lines when the vessel is moved. Tripping-speed was in average 200 meter per hour, and same speed is expected for the tubing-pulling operations. Both RLWI vessels and semi-submersible rigs have to lay down tubing in singles.

Island Offshore pipe handling system is fully automated system, e.g: no manual handling of drillpipe. The pipe is deployed with the main winch that is heave compensated. For retrieving tubing for the P&A operation the winch will be used to retrieve tubing to surface and the pipe handling system will disconnect the pipe and lay down the pipe on deck

Figure 36 Pipe handling system [26]

10.1.9 Retrieve tubing to surface or place at seabed

During a P&A operation there will be limited of deck space; an alternative is to wet-store the tubing on seabed in bundles instead of storing the tubing on vessel. The tubing can then be picked up with a cheaper vessel, like an IMR vessel (Inspection, Maintenance & Repair).

10.1.10 Risk register from Hazop

A Hazop was performed by Island Offshore , FMC, NCA; Halliburton and Statoil to evaluate the risk by using equipment suggested in the P&A study. A total of 34 items were recorded, below only the red risk are include.

Table 9 Main risk from Hazop

Guide word	Cause/Hazard descriptions	Consequence	Recommendation	Comments
Barriers	Inlet below safety head not according to requirements, and damage to inlets might occur unless well protected	Loss of barriers. Have to retrieve and repair the stack. Delays	Design to include protection. Don't run hold open sleeve for DHSV.	Not allowed to perform operations without deviation
Barriers	Subsea shut-off device will not be approved as a well control barrier	BOP may be required as an alternative SSD	Resolve SSD vs BOP issue	DNV has done a preliminary review of the SSD with regards to barriers
Barriers	Unknown status of cement behind 13 3/8" casing (requirement)	Not in compliance with the regulations when setting the cement barrier in the annulus between 9 5/8" and 13 3/8" casing	Log cement behind 13 3/8" casing through 9 5/8" casing	Technology gap
Barriers	Unable to verify barriers, Main bore and annuli	Barriers not established	Place/ circulate plug in annulus, log and set inside plug through flexible steel pipe	

10.1.11 Comments regarding retrieving tubing to surface

Applications areas that are able to us this combination of equipment (SSD, Volume Control system and Jack mechanism):

- Retrieving of tubing to surface
- Use of the tubing after cut for conveyance of cement
- Log cement behind casing with tubing partly retrieved
- Use of the Coiled Tubing to establish cement barrier or other application

Separately the technology in the study is field proven for every item as pipe handling, Volume control, Subsea Shutoff Device, Jack, Tubing hanger running and orientation tool. But the equipment have never been used in this combination It is possible to centralize the tubing with Jack and annular.

10.2 New approaches for removing tubing

10.2.1 Push tubing down by crushing tubing

Semi-submersible rigs are used for well abandonment required to remove components/tubing of a well prior to cement bond logging of the production casing.

Oilfield Innovation has taken patent on crushing tubing and production casing [31] on a rig-less concept. The tubing will be compressed together and an area (window) will be free to log cement behind casing and no tubing need to be retrieved to surface. The equipment is run on wireline and no marine riser is needed. Enormous forces need to be added to collapse production tubing. However, tubing that is even slightly deformed, damaged or worn, may collapse with significantly reduced force. A vertical cutter is used to weaken the tubing.

Abandonment method involves:
1) cutting the tubing with a vertical cutter
2) placing a piston
3) crushing the tubing to make space with pressure from above,
4) cement bond logging within the space
5) repairing leaks by squeezing cement behind the casing through perforations and/or placing a cement abandonment plug using the remaining tubing and annuli to seal hydrocarbons below the cap rock.

A cement retainer is used as a piston with viscous fluids (incl gradated material) and inflatable packers to provide a piston seal above which a heavy mud may be placed above to increase the pressure applied to the piston for crushing.

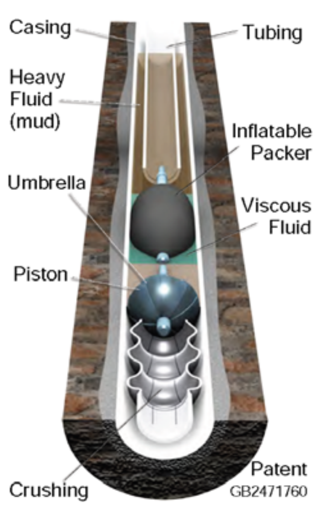


Figure 37 A cement retainer [31]

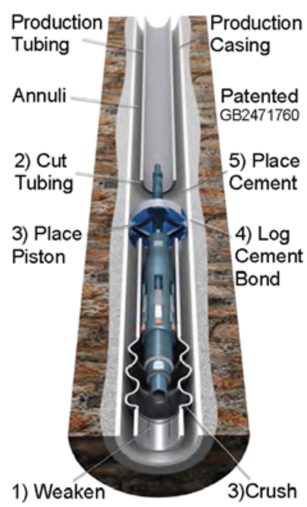


Figure 38 Rig-less abandonment [31]

Advantages: It will be possible to log cement behind casing without milling or retrieving tubing to surface. There will be no swarf to surface and no handling of tubing and casing at surface.

Risk and Concerns: The technology is new and unproved.

10.2.2 Use of chemicals to remove the tubing

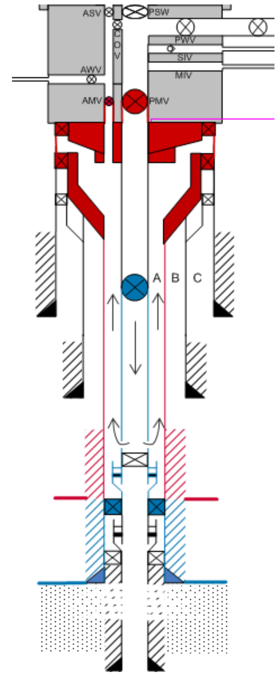


Figure 39 Chemicals to remove the tubing

Tubing and casing is made of various steel qualities. The material will react and corrode with different fluids. The history shows that the tubing corrodes in a corrosive environment and in some cases almost disappears. An out-of-the-box idea might be to evaluating chemicals to remove the tubing.

A mechanical plug should be installed prior to displacement of chemicals. The plug for this purpose should be coated to avoid reaction.

When the reacted fluid is used a new fluid need to be added to the same area. Alternatives to place the chemical:

1. Create a fluid circulation by punching tubing. Pump down tubing and up annulus
2. Spot the chemicals with Coiled Tubing. The wall thickness of the Coiled Tubing will also be reduced. It will be mportant to flush the Coiled Tubing between spotting of chemicals to reduce the risk of destroying the Coiled Tubing
3. Spot the chemicals with dedicated tool run with wireline to ensure that the chemical reaction take place at the correct depth. This is probably the best way to spot the chemicals.

Advantages.

- No handle of tubing at surface.
- No milling and no handling of swarf.

Dis-advantages:

- Risk Concern, correct placement of chemicals.
- The chemical can react with other equipment.

10.2.3 Remove tubing by melting

There is a technology on the markets that cut the tubing by melting, see Chapter [App G]. Another out-of-the-box idea might be to remove the necessary tubing length with the same technology as plasma cutter, but much stronger and more efficient? The plasma cutter can today cut all types of steel up to 7 5/8” tubing for temperatures up to 500° F(260°C) and pressures to 20,000 psi (137.8 MPa). Plasma cutters are able to cut in all kind of well fluids.This is completely uncharted territory for a plasma cutter and show stoppers can be: power requirements, challenges regarding waste product of melting and as the fact that standard plasma cutter have problem to come free. But another bi-product of the system can be that the melted product can act as a barrier in the well.

Advantages:

- No need to retrieve tubing to surface.
- There will be no milling and therefore no handling of swarf.
- Establish barrier?

Dis-advantages:

- Power requirements
- waste product
- problem to come free with BHA

10.3 Summary

Different methods for removal of tubing are seen and the results are shown in the table below. All option can be exercised from a RLWI vessel. None of the methods has been used on a RLWI vessel with purpose to remove tubing in a P&A context before. A chemical, like HCL, has been used to weakening coiled tubing in stuck situation. The suggestion to retrieve tubing to surface with SSD, Volume control and Jack will probably be the best solution in the near future, while the other options should be thoroughly evaluated.

Table 10 Different methods to remove the tubing with advantages and dis-advantages

Method	Subsea equipment	Advantages	Dis-Advantages
Retrieve tubing to surface with main winch.	SSD, Volume control	1. The technology of every single equipment parts are field proven 2. Enough pulling forces on the main winch for standard tubing retrieving.	1. Can be lack of pull forces when unseat the tubing hanger
Retrieve tubing to surface with main winch and jack	SSD, Volume control, Jack	1. The technology of every single equipment parts are field proven 2. Enough pulling forces on the main winch for standard tubing retrieving. 3. Additional pull forces compared with main winch 4. Centralized tubing	1. Stability of rig up: Additional weight and height due to more equipment rigged on top of each other.
Push tubing down by crushing tubing	Standard RLWI stack	1. No milling, no swarf to surface 2. No handling of tubing at surface 3. Not necessary to change subsea equipment. Save time and money	1. The technology is new and unproved.
Use of chemicals to remove the tubing	Standard RLWI stack or modified for coiled tubing	1. Chemicals that can remove tubing exist 2. No handling of tubing at surface 3. Exist equipment that are able to spot the chemicals 4. Not necessary to change subsea equipment. Save time and money	1. Use of chemicals for removing of tubing for P&A purpose is not field proven, just an idea 2. There is need of continuous fresh chemical. 3. Time consuming.
Remove tubing by melting	Standard RLWI stack	1. Melting of tubing is possible 2. No need to retrieve tubing to surface. 3. No milling and no handling of swarf. 4. Not necessary to change subsea equipment. Save time and money	1. Melting of tubing for removing is not field proven, just an idea 2. Molten steel may create problems in the well

11 Coiled Tubing operation performed Riserless using a Light Well Intervention vessel

If the concepts of performing Coiled Tubing operations from RLWI vessels can be realized, then it might be possible to extend the scope for P&A from only using wireline solutions.

11.1 Standard Coiled Tubing operation

Coiled Tubing (CT) is a continuous string of tubing that is coiled onto a spool. CT can be used for a variety of tasks such as sand cleaning, logging, cementing, perforation, pump chemicals and gases, and drilling operations. The Coiled Tubing equipment consist of well control package (shear seal, BOP, stripper), injector head, gooseneck, CT string, control house, powerpack, and pumps.

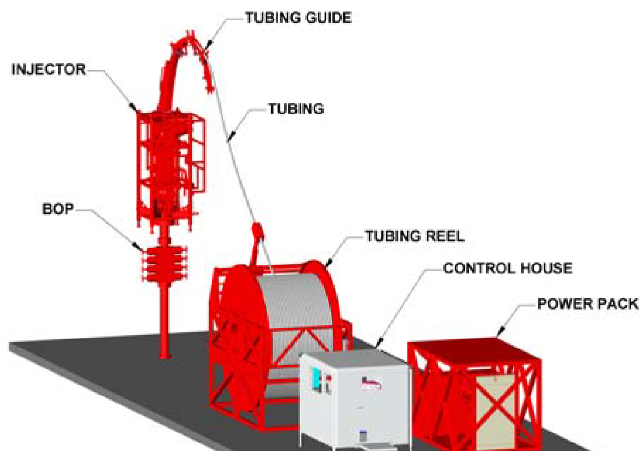


Figure 40 Standard Coiled Tubing rig up [32]

Normally semi-submersible rigs (Cat C) perform subsea Coiled Tubing jobs. The new Cat B rig will be able to handle such equipment.

The challenges regarding use of Coiled Tubing on a monohull vessel has been due to handling of equipment (risk for personnel), fatigue issue (both riser and Coiled Tubing) and handling of return with barriers in place. The acceleration and movement are higher on a RLWI vessel compared to a semi-submersible rig.

Different projects for Riserless Light Well Intervention Coiled Tubing have been evaluated during the last years, and some of the projects are listed in the table.

Table 11 Different projects for Riserless Light Well Intervention Coiled Tubing

Company	Name of the project	Description	Challenges
GoM/Blue Ocean	Open water CT	Coiled Tubing in open water.	To heavy and expensive
BJ services/Exxon Mobil	SIM (Subsea Intervention Module)	SIM was a subsea installed Coiled Tubing system. Reel as well.	To heavy and expensive
GE-Vetco	RICTIS	Open sea	Subsea injector. Fatigue of coil in well
Statoil/Halliburton	SWIFT	Coil in coil	Lock up of coil inside outer coil
Island Offshore	OWCT	Coil in open water. Injector installed at seabed	Fatigue

11.2 Open Water Coil Tubing (OWCT)

Island Offshore is now developing an “Open Water Coil Tubing” [24] system which is planned to be operated from RLWI Vessel Island Constructor. The main focuses for the CT operations are sand clean out and cementing for P&A purpose.

The reel, power pack, pumps, control house is placed on deck. The stack (BOP), stripper, and subsea injector is rigged up in tower, and subsequently deployed subsea. The gooseneck, and upper injector stays in tower during operation.

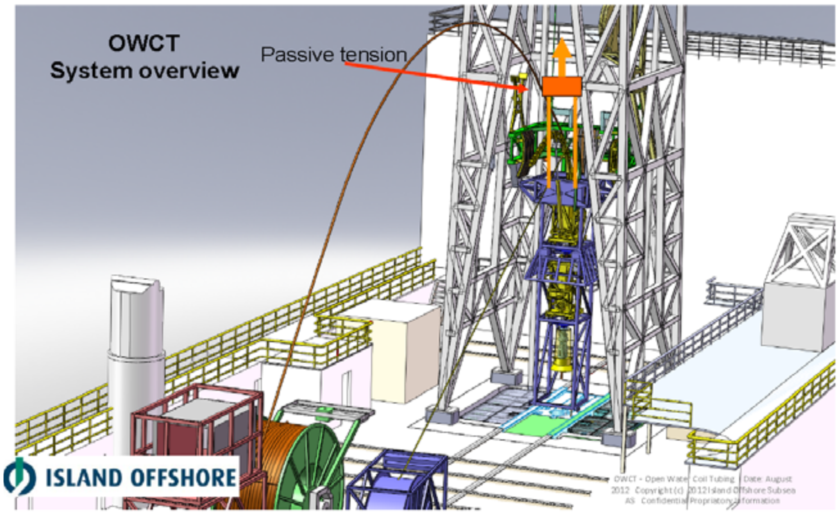


Figure 41 Drawing of Coil Tubing system onboard on RLWI vessel [24]

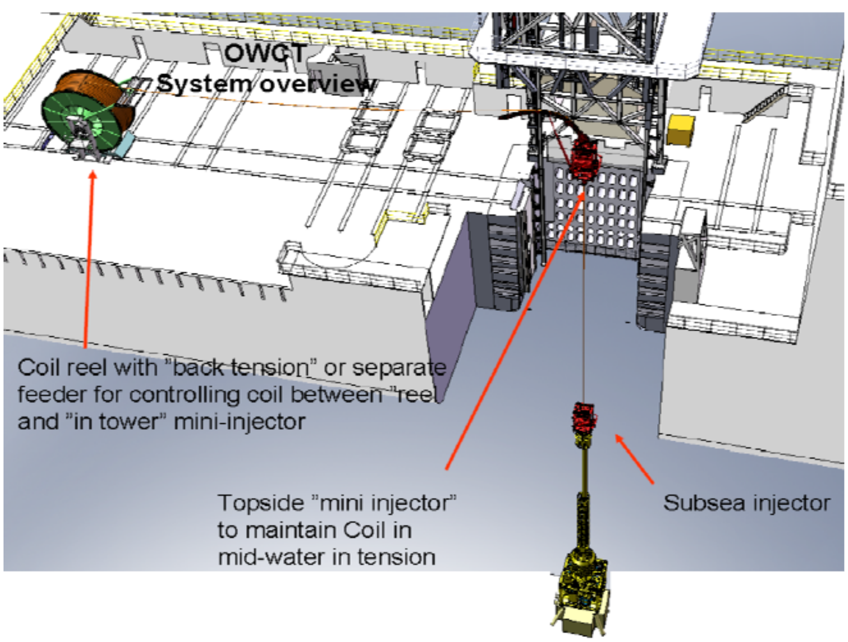


Figure 42 Open Water Coil Tubing –System overview-Island Offshore [24]

The system contains of three injectors. One mounted on CT reel to act as a feeder for controlling Coil between reel and tower, the second is topside mounted below gooseneck to maintain Coil tension during operation in open sea and to retrieve Coil while POOH, and the last one is a subsea injector providing a snubbing force to feed the coil into the well.

The subsea injector has a complete dual drive system and a special attention has been paid to the redundancy system (back- up). The injector is produced in aluminum and titanium due to the weight. Injectors can be deployed with or without tubing installed. While changing out BHA the injectors and strippers are opened and the BHA is possible to retrieve through. Max OD of BHA through strippers is 6”.

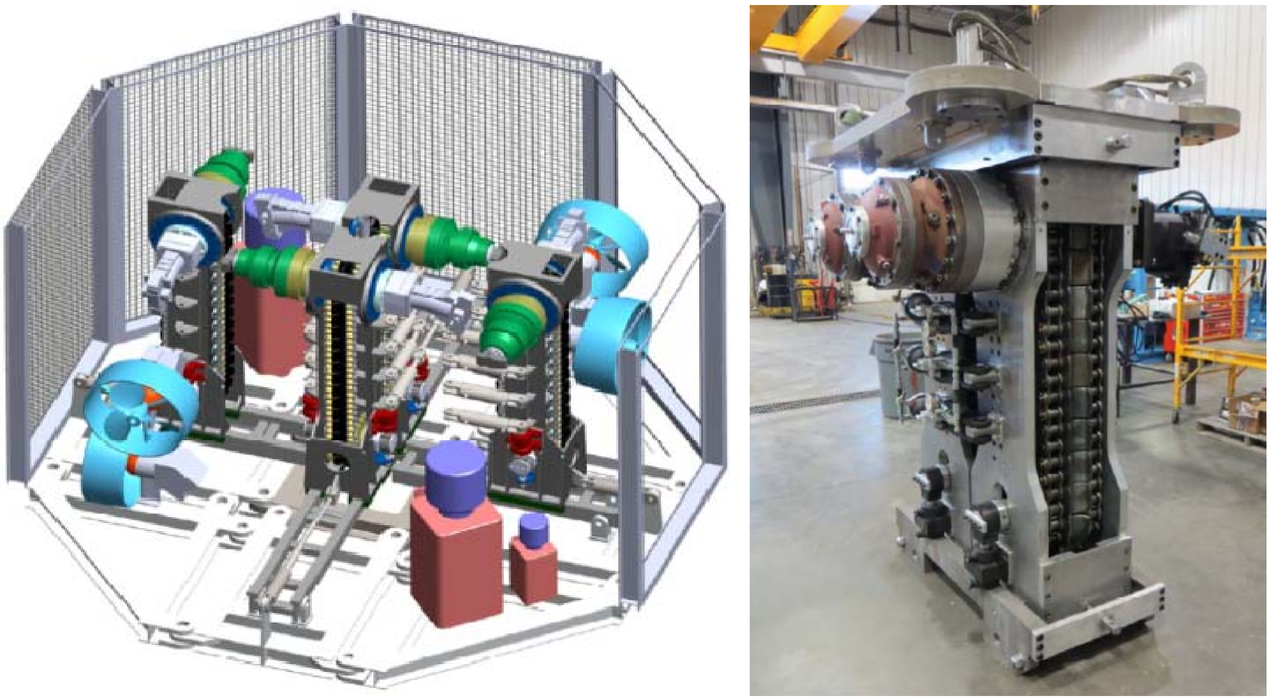


Figure 43 Drawing and picture of Subsea injector [24]

For standard RLWI operation only WL and bullheading operations are possible. It is only possible to circulate tubing and annulus when tubing is punched or cut. By implementing CT on the RLWI vessel new opportunities open up. On next side circulation options through CT are showed.

a) Concentric coil –“Coil in coil”
b) Additional kill hose connected to stack. 2 kill hoses of 2” to be able to handle return
c) 3”- 4” hose to vessel, constant tension wire having compensation loop top side
d) Use of hose and subsea booster pump for deep water application

11.3 Comments

It might be important to differentiate between RLWI vessel that perform P&A operations and standard wireline operations. Coiled Tubing options from RLWI will probably have more chance of succeeding in P&A scenarios, due to possibility to clean out well, place the cement barriers and pump abrasives.

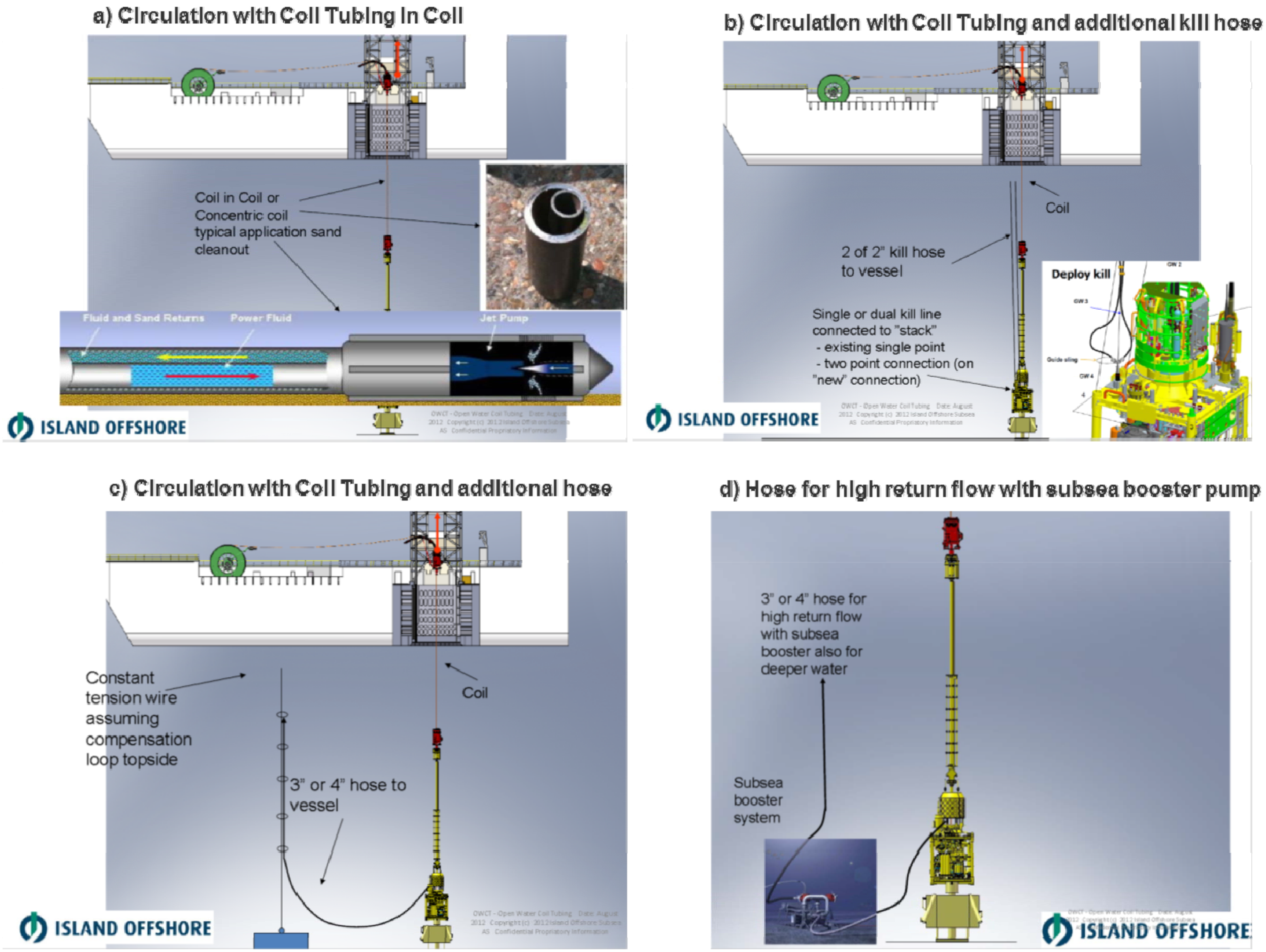


Figure 44 Different circulation alternatives with Coiled Tubing [24]

12 Different approaches for installation of barriers

Establishment of a cement barrier plug is normally performed from a semi-submersible rig with drill pipe, and the “perf and wash” method to install barrier in annulus with lack of cement or not qualified. It is seldom today that section milling is performed to establish barriers in annulus. Worth considering is that cement material can be contaminated while displaced downhole. In this Chapter different approaches for installation of barriers as plug or in annulus is described with or without coiled tubing.

12.1 Install cement barrier plug - No Coiled Tubing

12.1.1 Use cut tubing to place the barrier

An alternative that has never been performed is to use the tubing to install the cement barrier in place [27]. After a mechanical plug is installed in the tubing, and the tubing is cut above it is possible to pump cement through tubing instead of drillpipe to install the cement barrier plug. A moffat coupling with an umbilical will be installed on top tubing to pump through and the return will be on the umbilical (or choke line) connected to the subsea shutoff device. Cementing through tubing will be further described in Chapter (15).

12.1.2 Bullhead cement through tubing

It is possible to bullhead cement and squeeze it into reservoir through tubing. This has been done with a RLWI vessel. The cementing job was performed through the well control package. For similar operation in the future a cement spool installed below Stack (well control package) is recommended to avoid RLWI Stack being affected by cement. This is performed before the VXT is removed and the return can be taken via the annulus side

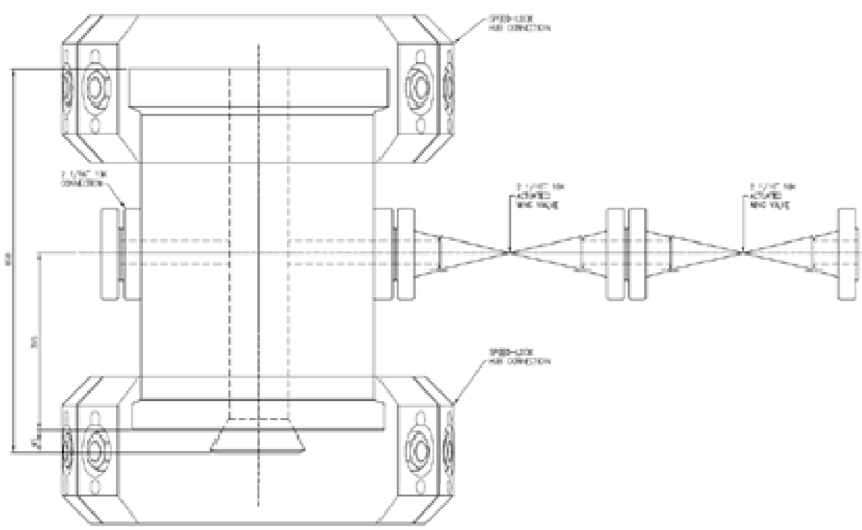


Figure 45 Cement spool [27]

12.2 Install a cement barrier plug – Coiled Tubing

12.2.1 Use coiled tubing to place the cement barrier plug

If coiled tubing is available on the vessel the tubing can be used to install and place the cement barrier in the reservoir or establish a cement plug in the casing when cement outside the casing is verified. An alternative that has not been performed as of today is to establish cement barrier with coiled tubing without riser. Less contamination of the cement will occur and therefore improved quality of cement plug will be expected.

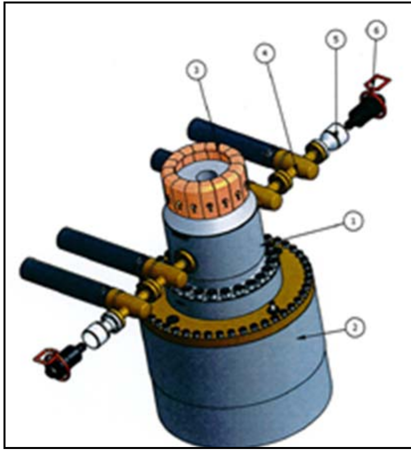
12.3 Install or repair annulus barrier- No Coiled Tubing

12.3.1 Cement Adapter Tool w/stinger and cement spool

Cement Adapter Tool can be in P&A operations on wells that have one or two annuli un-cemented.

Placement of an additional permanent barrier is required to complete the abandonment of the well. This may be done by placing a barrier into the annuli or placing a separate barrier. This type of well may be abandoned with a light-well intervention vessel with full well control. It allows intermediate cement plugs to be placed in casing and annulus with the stack installed on the well [41].

- Interface between the wellhead and the LWI package
- Allows selective perforation of production casing to establish lower and upper annulus communication
- Provides interface for CAT stinger.
- Circulating route for annulus cleaning (forward and reverse with returns to the vessel), and squeeze cement in annulus
- Allows for pressure testing of cement plugs
- Maintains control of well barriers together with stack.



ITEM	SUBJECT
1	CAT spool
2	18 ¾”, 10 K Cameron hub connector
3	13 5/8”, 10 K Speedlock II
4	2 1/16”, 10 K, Subsea Actuated gate valve
5	2 1/16”, 10 K, Subsea receptacle
6	2 1/16”, 10 K Stab connector

Figure 46 Cement adapter tool [27]

CAT stinger assembly To be installed in the CAT spool to seal between stinger OD and production casing ID to isolate upper and lower perforations in production bore. The stinger has a standard wireline running tool profile. The lock mandrel is mechanical set in CAT spool nipple profile.

Max stinger length:21 m (included tool string).Minimum stinger ID: 1,5 in and maximum stinger OD: 7,030 in LWI drift (7/16" in, 10 K, nominal bore).Hydraulic inflatable packer to set in 9 5/8", 10 ¾" and 13 3/8" casing, the packer allows circulation to set cement barrier.

A cementing adapter tool allows cement barrier to be placed in casing and annulus for both open hole to surface and for intermediate barrier, performed from an intervention vessel without the need for a riser.

There is no limitation of the depth of the barrier that can be installed with use of CAT tool. The tool allows selective perforation of casing to establish lower and upper annulus communication ports (wireline run through well control package and CAT). The CAT stinger seals between stingers OD and casing ID to isolate upper and lower perforations in production bore. A circulation route will be established for annulus cleaning, and displacement and spotting of competent cement (annulus and balanced)

The CAT system allows for pressure testing of cement plugs and in combination with the Well Control Package, maintains well barriers/control during above operations.

One issue can be regarding cement contamination during installation of the deep set cement barrier.

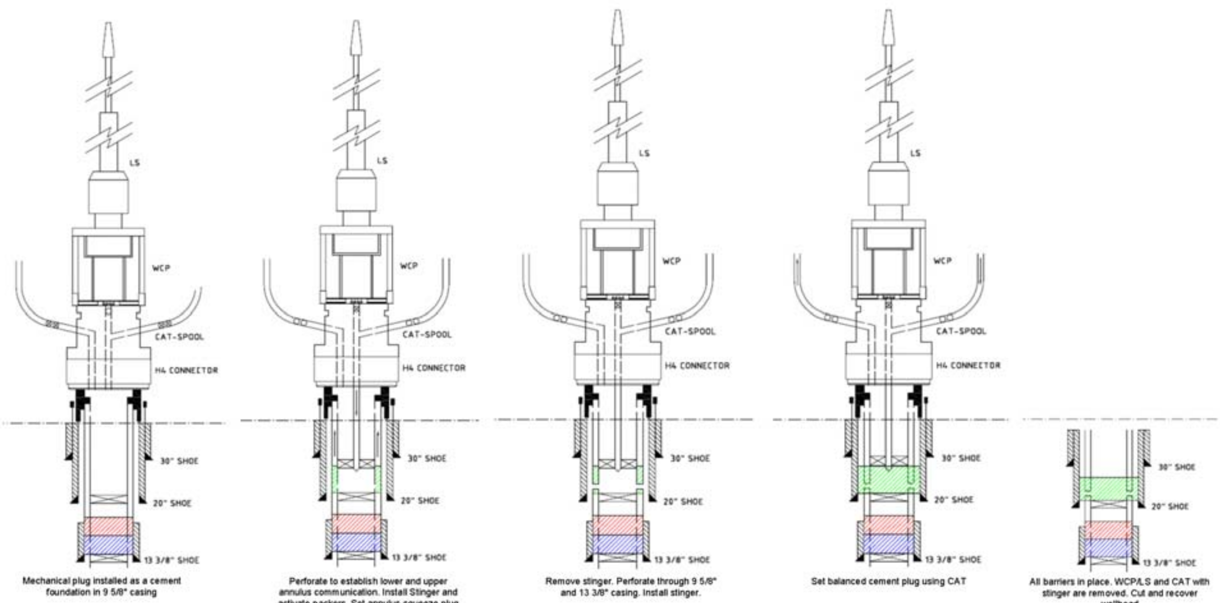


Figure 47 Establish cement barrier by using CAT operation

12.3.2 Well Abandonment Straddle Packer (WASP)

The WASP tool [18] from Baker Hughes has more or less same function as the CAT tool to establish annuli barrier. The tool has been operated from different vessels in UK. The WASP tool lands and seats in the HP wellhead housing and in a single trip system it provides isolation, shut-in casing perforation, displacement of OBM and annulus cement. The system consist of two inflatable packers for isolations and two pairs of selective perforations guns. Three sub-surface controlled safety valves are incorporated for emergency shut in.

Normally the WASP tool is operated without any BOP, only umbilical connected to the WASP tool allow circulation back to the vessel

WASP operation: Establish sealing off the wellbore and perforate the first annuli below the bottom packer and between the packers. This circulation path is used to install a cement barrier in A-annuli. The second annulus is then perforated through casing and existing cement barrier with a more powerful perforation guns. The annuli is then cemented and tested.

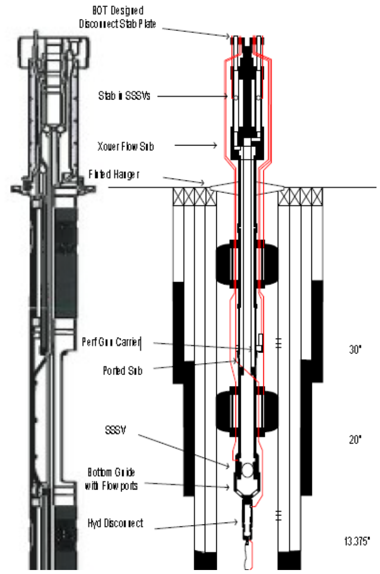


Figure 48 Well Abandonment Straddle Packer [41]

12.3.3 Suspended Well Abandonment Tool (SWAT)

Suspended Well Abandonment Tool (SWAT) from Claxton engineering has been used in many years in UK sector to establish the open hole to surface barrier plug [10]. The operation is normally performed from back of a vessel or through a moonpool. The system permits perforation, circulation and cementation of multiple casing annuli while maintaining appropriate pressure control barriers. No riser is required to perform the operation.

SWAT procedure [9]:
Deploy the SWAT tool and inflat lower and upper packer to isolate towards the casing. Perform pressure tests. One of the lower perforation guns perforate 9 5/8” casing. One of the upper perforation perforate casing to establish a circuation path. Pump clean up pill, spacer and then cement. After the cement in A-annulus has been set, the other lower perforation gun perforate through 9 5/” casing, cement and 13 3/8” casing and the last upper guns perforate to estblish new circulation path. Clean and cement B-annulus. Fill the well with sea water. Performed final pressure test

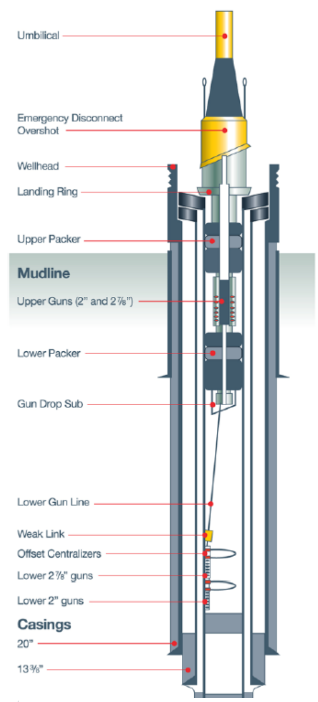


Figure 49 Suspended Well Abandonment Tool [10]

12.3.4 Comments

The Cement Adapter tool (CAT) is able to establish primary, secondary and open hole to surface barrier. The CAT will be run together with a standard RLWI stack. There is no experience with use of CAT.

SWAT and WASP tool have long experience on establishing open hole to surface barrier on UK sector. The cementing devices are run without RLWI stack. It is necessary to use RLWI stack simultaneously as the cement device to obtain sufficient barriers control throughout the operation when the primary and secondary barriers are not established.

12.4 Install or repair annulus barrier- Coiled tubing

Different tools are on the market and some are under development. This equipment can reduce the need for section milling. The section milling was necessary to remove casing to cement the full cross section.

12.4.1 Perforate, wash and squeeze techniques, HydraWash

HydraWell Intervention has developed a tool (HydraWash™-Patent Pending) that enables permanent plugging of wells without performing any milling operation. The HydraWash™ tool is connected to TCP guns and the workstring. The Perforate, Wash and Cement (PWC) system [45] perforate un-cemented casing washes the annular space and then mechanically places the cement across the wellbore cross section in a single run. The benefit of this tool in cost reduction due to time saving, and another improvement is no handling and disposal of swarf. Swarf is metal filings or shaving generated by a cutting tool. The Swarf increases the Equivalent Circulating Densities (ECD) which can exceed the fracture gradient of the exposed open hole that again leads to challenges to handle.

The PWC system creates an abandonment plug that can be verified in the annulus, by milling out the plug, and log the cement in the annulus to provide competency verification. A new cement plug has to be installed afterwards and verified inside the casing. Operator's typical drill out and log PWC plugs initially until the concept is field proven. Then the plug is qualified according to NORSOK D-010 by pressure testing or tagging.

The operation need to be performed by pipe (Drillpipe or Coiled Tubing).

The tool length: From bottom up, it consist of typical 50 m of drill pipe conveyed perforation guns which drop on firing, above the guns is an opposed cup wash system with ball release which is left in the hole as a base for the cement job and on top of the wash tool is a cement stinger.

Figure 50 HydraWash tool [20]

12.4.2 HydraHemera

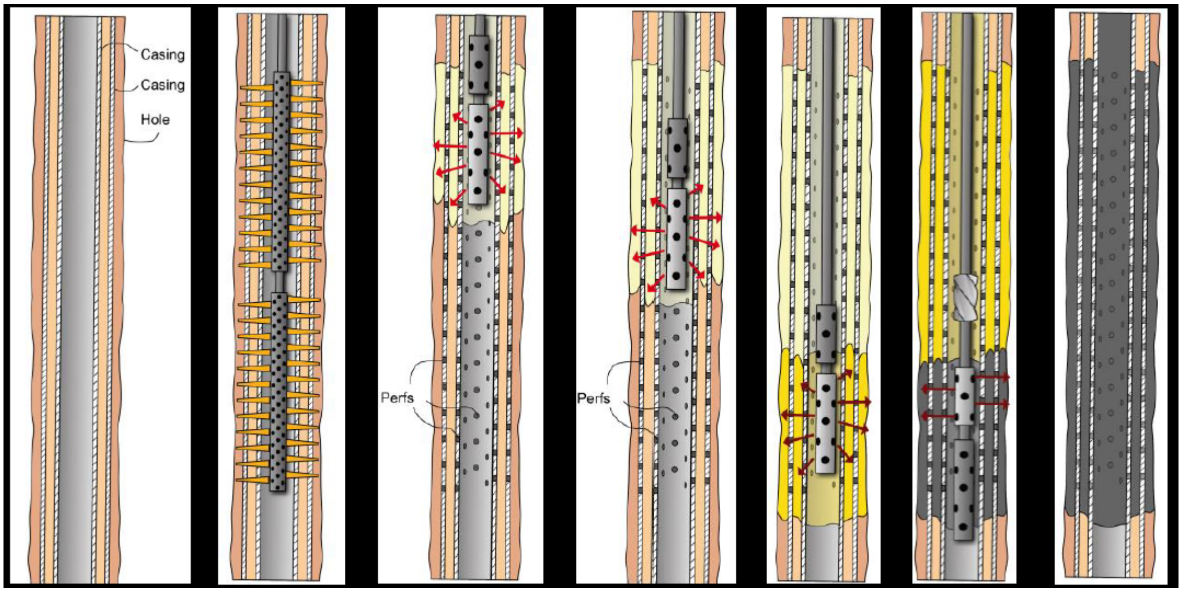


Figure 51 Running steps for HydraHemera^TH [22]

HydraWell and ConocoPhillips have in co-operation developed a system for P&A of multiple casing strings called the HydraHemera™ system (Patent Pending) [22]. The differences between standard HydraWash™ tool and HydraHemera™ are:

- Bigger and denser perforation guns
- Wash sub with high pressure nozzle
- Create a base for cementing in multiple annuli

Bigger and denser perforation guns: To get access to all the annuli, big hole charges are used, typical 0,7”-1.0” and at least 18 spf, to wash all the annuli with the high pressure fluid. If conventional HydraWash™ system was used in multiple casings, the flow will follow the path of least resistance avoiding proper clean out of all the annuli and resulting in no proper cross-sectional plug.

HydraHemera™ Wash tool: New wash tool for multiple casings.

Create base for cementing in multiple annulli: A HydraKratos™ (Patent Pending) detonating tool is connected in the lower end of the TCP gun assembly. Setting off the HydraKratos™ tool results in expansion of casings and remove of annuli gaps. This will create a fundament in the annuli for the cement. For a regular HydraWash operation, this is achieved with an RTTS with squeeze guns

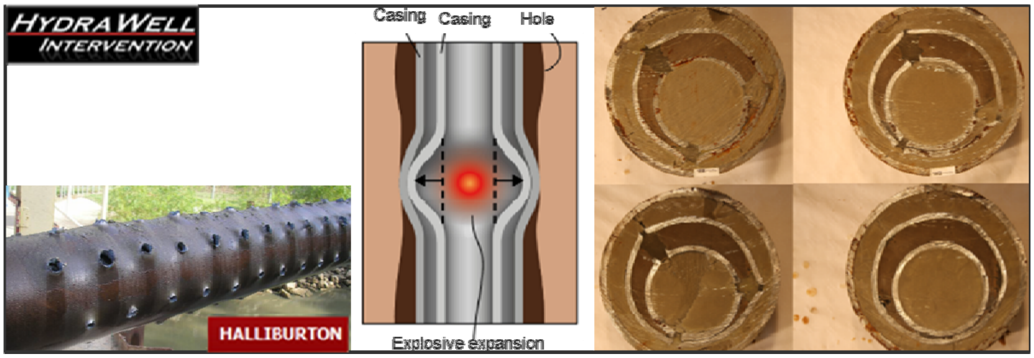


Figure 52 a) Perforated casing. b) Explosive expansion. c) Cut of cemented casing [46]

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12.4.3 Perforate and Wash - Archer

Archers “Perforate and Wash” tool (PWT) perforate casing/liner section, wash and clean the perforated zone and enable permanent cement barrier between casing and formation. All this steps is performed during a single trip. This method has more or less the same functions as the HydraWash tool. This method also eliminates the need for milling and debris handling (swarf).

The operation of the one-trip PWT tool is straightforward. It consists of perforating (the guns drops after perforation), washing the perforated section and then drop the PWT tool, and place the cement plug. If needed, it is possible to perform drilling and logging of the annular cement, and replacing the cement plug within the casing. The application for this tool is permanent abandonment and screen washing. Some of the features of the PWT tool are adjustable distance between swab cups, dual swab cup design, flow by-pass system, and drop off system. Some of the benefits are no surge or swab effect due to trip in and out, eliminates need for section milling, no handling of swarf, efficient due to one trip (time and cost saving), effective establishment of cement barrier

Figure 53 Perforate & Wash tool [6]

12.4.4 Abrasive cutting tool

Halliburton has developed an abrasive cutting tool. Successfully testing has been performed. The tool is able to cut casing, tubing and control lines [17].

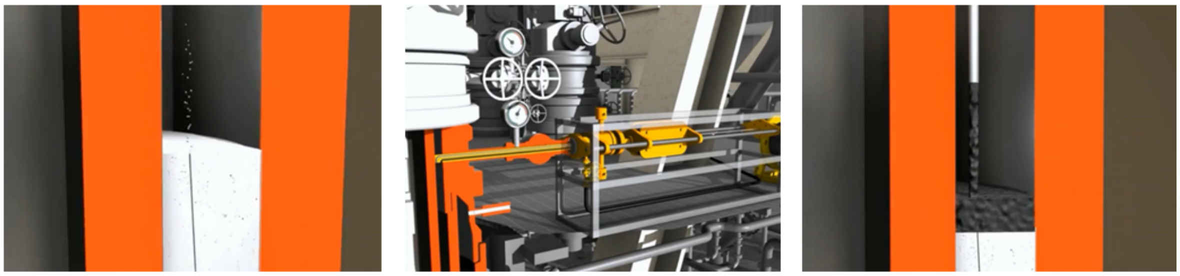
The method uses a high energy jet of water-borne abrasive particles which will cut the hardest steel alloys. The abrasive jetting technology slice the casing section into smaller pieces, cut first vertical and then radial, which then can fall down further into the well. The abrasive sand content is 0,5-1 ppg in water and the sand can be recycled 3-5 times.

The abrasive cutting tool is to be used for section removing to be able to log cement behind casing and when the quality of cement is not sufficient, necessary to create full cross section well barrier of the well. Estimated time for removing 50 m window is 36 hours. There is no limit on max section length to be cut, and this is a benefit compared to other.

Figure 54 Free brackets from a test [17]

12.4.5 Casing Integrity System

Quality Intervention has developed an annulus intervention technology called Casing Integrity System (CIS) [35]. The CIS deploy a 3/8" Coiled Tubing (CT) in annulus under pressure. The CT is possible to bend 90 deg (see video [35]). By using Coiled Tubing it creates possibilities to circulate inside casing annuli and install barrier material. There is no need for a rig. This technology is designed to pump cement in the annulus B from a platform, when the quality of the cement or the length is not sufficient. There is no access to the B annulus from a subsea well, but the technology may be modified to be used in in the A annulus when the tubing is not needed retrieved. A subsea injector is required to be installed on the XMT.



Leaking cement | Deploying CT with CIS rig | Cementing annulus

Figure 55 Operation of CIS [35]

12.4.6 Comments

Statoil does have good experience from semi-submersible rigs "Perforate, wash and squeeze techniques" from HydraWell and "Perforate and Wash" from Archer. Both system are run on drillpipe, the systems perforate, wash and place the cement to establish cement barrier. HydraWell and ConocoPhillips have in co-operation developed a system for P&A of multiple casing strings called the HydraHemeraT^{M}. The differences between standard HydraWash^{TM} tool and HydraHemera^{TM} are bigger and denser perforation guns, wash sub with high pressure nozzle and creation of a base for cementing in multiple annuli.

The abrasive cutter from Halliburton has no limit on max section length to be cut, and this is a benefit compared to other. The abrasive cutter is able to cut control lines, demonstrated on test. After the casing is cut, cement barrier is possible to establish.

The casing integrity system from Quality Intervention is use of thin Coiled Tubing. The technology is basically designed to repair B annulus on platform.

13 Barrier materials

13.1 Barrier material approved for use in Statoil

Today only cement and bonded shale are recognized as a permanent plugging material by Statoil. Bonded shale is preferred barrier element outside casing used in permanent P&A. However presence of bonded shale cannot be predicted; and therefore it shall always be planned for using cement as back up.

13.1.1 Portland cement

Portland cement [19] is the most common type of cement used for cement barrier in hydrocarbons wells on the Norwegian Continental Shelf. The cement is grinding into small pieces usually 3-25 mm in diameter (clinker). The cement material consists of limestone, calcite, marl, clay, shale, aluminum oxide, mudstones, and calcium sulfate (gypsum). By mixing the cement with the right amount of water it created slurry that is designed to harden when the cement is pumped and placed at the final position within a wellbore. Portland cement is hydraulic cement means; it hardens by reacting with water and forms a water-resistant product. The cement material consists of two-thirds by mass of calcium silicate, and the remainder consisting of aluminum-and iron containing clinker phases and other compounds. Cement is a conventional material. Changing of pressure and temperature can lead to cement cracking, and leak path can occur.

The standard weight by cement slurry is typical around 1,92 sg. Additives can be added to the cement slurry to reduce the challenges for cement for long term isolation as elasticity, shear strength, hydrate shrinkage, compressive strength reduction and tensile strength.

Standard additives used in the cement mix and their respective effect are described in the table.

Figure 56 Cracks in the cement [33]

Table 12 Cement additives [40]

ADDITIVE	EFFECT
Accelerators	Accelerate gel development, make slurry thixotropic
Bulk flow enhancers	Reduce packing tendency of bulk cement
De-foamers	Prevent foam
Dispersants	Reduce viscosity, improve fluid loss, prevent gelation
Elastomers	Enhance elasticity
Expanding agents	Expand cement during and after hydration
Extenders	Viscosity, tie up excess water, prevent fluid loss
Fibres	Enhance tensile strength, prevent cracking, avoid chunk fall-off
Fluid loss control agents	Control fluid loss
Foaming agents	Create stable foam
Gas generators	Produce H2 to increase compressibility
Gas migration prevention agents	Prevent gas migration during the transition phase that takes place mainly right after placement. During placement is the ECD that stops the gas influx
HT stabilizers	Viscosify of high temperatures, control thermal thinning
Light weigh materials	Reduce density
Lost circulation material	Mitigate losses
Nitrogen	Used with foamers to create foam slurries or foam spacers
Retarders	Control thickening time
Strength Stability	Avoid loss of strength and increase of permeability
Weighting Agents	Increase water ratio to make heavy slurries mixable and pumpable

13.1.2 Formation as barrier

Formation as annular barrier [69] was discovered after several observations of bonding properties located above theoretical top of cement. Bond logs showed solids material behind the casing far above expected cement top. Clear correlation of this bonding pattern to shale, indicates that the shale has sealed off the annular region and that was the presence of such formation material that resulted in a good bond log response. To gather information regarding cement bonding traditional sonic and ultrasonic azimuth bond logging provides information.

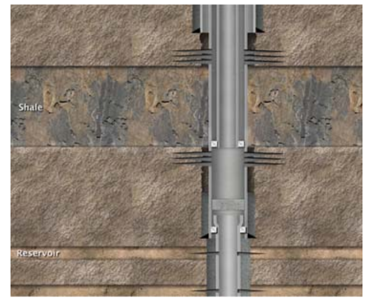


Figure 57 Shale as barrier [70]

To use formation as barrier, two criteria must be documented according to Well Integrity Manual (TR3507):

1. Sufficient rock strength to withstand the pressure it might be exposed to, qualified by pressure testing.
2. Interpretation of Wireline bond logs, verifying minimum 50 m of continuous and isolating formation bond.

Bonded shale formations cannot be predicted. Therefore, operation produces should include using cement or other qualified plugging material on the outside of the casing. But once collapsed formation is proven in place and qualified, it can be used and it is preferred used in PP&A.

Statoil has managed to get approval by PSA (Petroleum Safety Authorities) to use of formation as barrier. Statoil is the only oil company that uses this as a routine operation (Statoil has a patented solution). BP is considering using formation as a barrier on P&A operation for older wells in Norway. In other parts of the world, like Gulf of Mexico it is normal to use salt as a formation barrier.

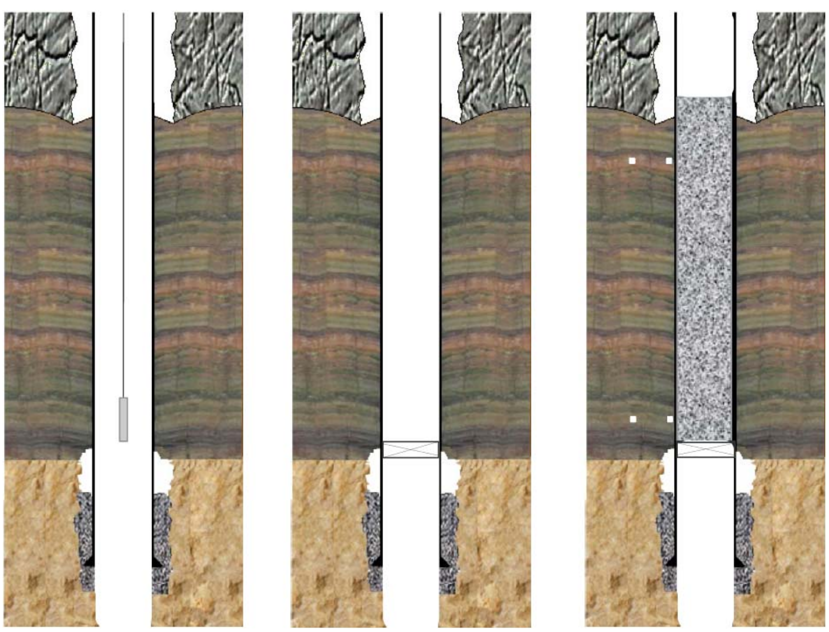


Figure 58 Collapsed formation as barrier element in a P&A operation

Procedure for use while using collapsed formation as barrier element, the step is showed in Figure 58:

Step 1: The formation can be qualified as a barrier element after sufficient logging and pressure testing result. The collapsed shale formation is in contact with outer casing.

Step 2: A bridge plug is installed as a barrier fundament.

Step 3: Install cement barrier plug in casing.

Example Shetland Clay:

As part of a plug and abandonment with slot recovery a Cement Bond log were recorded in a 9 5/8" casing. To verify the formation to casing bond logs were run in the Shetland clay sequence and confirmed the displaced Shetland formation as the secondary well barrier to the reservoir. The interpretation of the log showed chalk beds that had not bonded appeared as liquid filled pockets and Shetland Clay displaced against the casing.

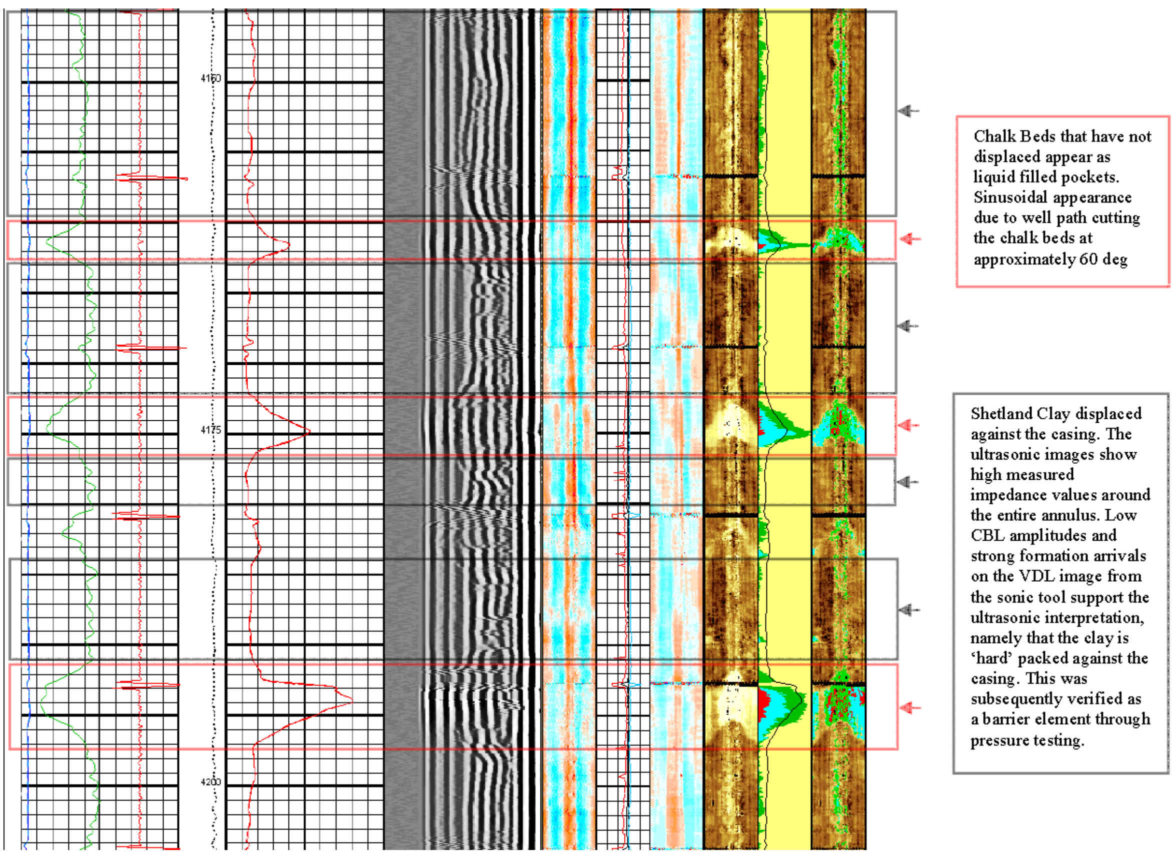


Figure 59 CBL/VDL and Ultrasonic Cement Bond Logs over and interval in the Shetland Clay [42]

13.2 Alternative barrier material

13.2.1 Sandaband

Sandaband [43] is an alternative to cement and formation barrier. Sandaband has Bingham-plastic properties with unconsolidated plugging material with high solids content. Sandaband consist of about 30% liquid and 70% solids by volume. The Sandaband is pumped as a liquid, but sets up as a solid mass when in place.

This method avoids well integrity issues because Sandaband is non-reactive, gas tight, no able to fracture and there is no volume shrinking. When the shear forces exceed its strength, the material start to float and the plug reshapes (repeatedly reversible forever).

The liquid is coating the solids particles, and the solids move relatively to each other after the material is in place, and no segregation will occur. Particle distribution on Sandaband is from 0,1μm to 2500 μm and specific gravity is ca. 2.15 s.g.

Advantages: Sandaband can effectively bridge off the mount of large fracture and be used as LCM.
Dis-advantages: Sandaband can bridge off holes/pipes smaller than 2 cm (3/4") in diameter.

P&A benefits using Sandaband:

1. No need for milling when removing- save time
2. Easier to place than cement-save time
3. Does not set up prematurely –Less risk
4. No losses to formation
5. Non-hazardous and environmentally friendly
6. Ductile and adaptable, no fracture, no leaks
7. No issue with downhole fluid contamination
8. Robust and non-complex-relies purely on physical properties

Figure 60 Sandaband [37]

13.2.2 ThermaSet

ThermaSet [33] is polymer based resin which is activated to set by temperature. Based on the design the plug can take from minutes to days to be thermally activated to set. The resin is a fluid when being pumped, but once the plug is thermally activated to set, it hardens and changes the properties completely. The density range is from 0,65 sg to 2,5 sg.

ThermaSet has much higher tensile strength than cement, more elastic, tolerate temperature expansion and do not crack.

ConocoPhillipse has used ThermaSet for P&A purpose on Ekofisk Bravo in a highly permeable chalk reservoir. The ThermaSet (0,85 sg) was pumped through collapsed tubing, squeezed the fluid through the perforation, into the reservoir and kept the top of the plug above the collapsed point. After setting time the plug was tagged and pressure tested.

Figure 61 Liquid ThermaSet [13]

Table 13 ThermaSet versus cement [33]

Properties	Advantages	ThermaSet®	Cement
Temperature Range	Low & High Temperatures	5 /130° C (200° C)	
Density Range	Balanced plugs	Min 0,75 SG Max 2,5 SG	
Tensile Strength	Much higher strength	Max 60 MPa	Max 1 MPa
Rupture Elongation	More elasticity Tolerates temperature expansion. Does not crack	Max 3,50 %	Max 0,01 %

13.2.3 Comments

The most effective and cheapest barrier is formation as barrier. There are no expensive chemicals involved and no heavy equipment needed for operation. Verification is necessary to confirm sufficient properties, and may be difficult.

Cement has been used since the beginning of the petroleum industry, and is the conventional plugging material. Other materials have been, and could be reviewed in the future. Statoil is in the process of qualifying Thermaset at the moment. Statoil had looked at Sandaband, and have not, as yet, qualified it to be used as a permanent barrier material.

Statoil does have plans to use Thermaset soon, as a LC material and as a fundament for the plug
For RLWI purpose it is not easy to determine which barrier material that is recommended; the advantage to use cement is well known, Sandaband is possible to re install if necessary, but the Sandaband can move after the barrier plug is in place. ThermaSet is fluid and easy to pump. Combination of different plugging materials is deemed favorable and is under development.

14 Technology for other P&A operations

14.1 Cut and Retrieve Wellhead

According to NORSOK [30] and Statoil [67] requirements there shall be no obstruction related to operation (drilling/well) left behind on the sea floor. In the end of a P&A operation the casing is cut and the wellhead is removed. The cutting depth should be minimum 5 meter below seabed. However, for a cutting depth beyond 2 meter below seabed no remediate actions are required.

14.1.1 Subsea Wellhead Picker:

Island Offshore has in co-operation with Oceaneering (Norse Cutting and Abandonment (NCA)) performed cutting and retrieving of several wellheads with Subsea Wellhead Picker and a wellhead connector [29] for RLWI vessel Island Constructor. The job was performed on UK sector for Interact Project Management Ltd.

The Wellhead Picker combines a connector that latches onto the wellhead and the Internal Multistring Cutting tool based on Abrasive Water Jet Cutting tool.

Abrasive Water Jet Cutting (AWJC): The method also uses a high energy jet of water-borne abrasive particles which will cut even the hardest steel alloys. The AWJC can cut more than 10” thickness and several layers.

Internal Multi-String Cutting Tool (IMCT): The IMCT produces a clean and even cut. The IMCT is proved for cutting of 5 layers from 7” inside to a 36” outer conductor in one run. There is no use of explosive charges. The system has a computer based control and monitoring system.

Figure 62 Casing cuts [29]

14.1.2 AXE-cutting system

Helix has performed several P&A jobs with LWI vessel on UK sector, but they have mainly performed the final part of P&A. This means setting an environment plug (SWAT tool) and removing wellhead.

WellOps (Helix) [18] cutting system AXE is a rigless wellhead removal system, capable of cutting through casing from 7” through to 30” in a single cut. The 10,000 -15,000 psi ACE water jet systems can cut umbilical’s, subsea flowlines, well conductors and casing. Working pressure is 14,500 psi (1000 bar)

The system can be operated using an ROV, deployed from a non-specialist vessel (eg RLWI vessel) and can operate at depths of max 200m.

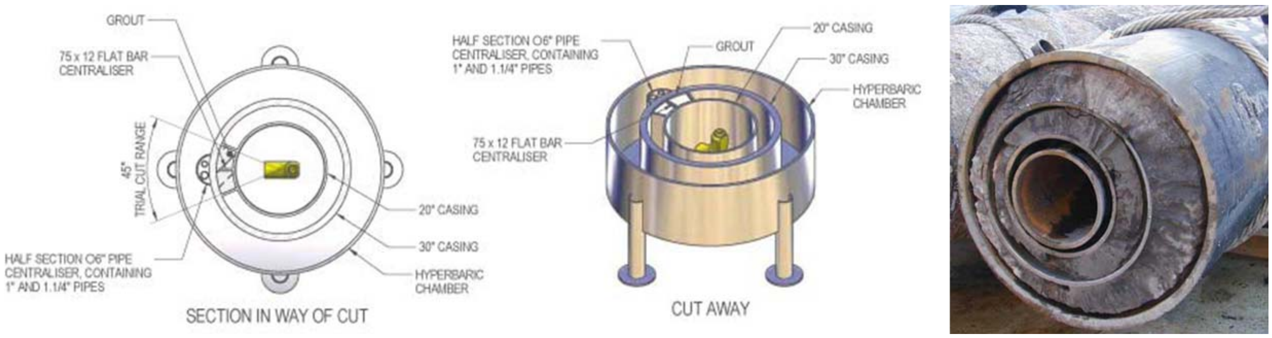


Figure 63 AXE cutting system and result after a cut of casing and cement [18]

14.1.3 Alternative to logging

An alternative to logging through multiple casing strings can be to perforate through two casing and perform minimum horizontal stress test to verify the formation strength. After sufficient pressure test new cement need to be squeezed into the formation and channels. Operation steps: Install plug, perforate several intervals, pressure test each interval to minimum horizontal stress and establish cement plug in wellbore.

The hydraulic sealing was verified by perforating through 9 5/8” and 13 3/8” casing:

-Displaced the well to brine prior to perforation
-Perforated several intervals
-Pressure tested perforation with Archer PWT
-Pressure tested each interval to minimum horizontal stress

Conclusions after the operation:

-There was no communication to surface during the test
-Difference in pressure vs time plot for testing in casing and testing of perforation confirms contact with the formation
-All tests was successful
-Placed three cement plugs of 25 m each
-The well was left temporary with a 9 5/8” dummy hanger
-The pressure was monitored to evaluate to do the remaining work rigless (Without BOP)

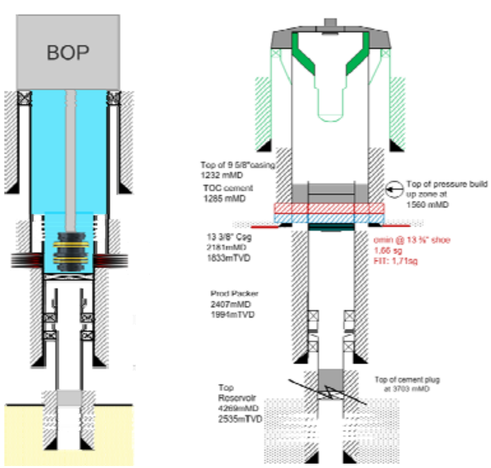


Figure 64 Drawings of the well during operation and as left temporary

15 Perform a full P&A on Well X with RLWI vessel

In this chapter an analysis of a permanent plug and abandonment operation conducted from a Riserless Light Well Intervention vessel will be described. Solutions to the challenges regarding retrieving of tubing and cementing without Coiled Tubing will be discussed and highlighted. The equipment will mainly contain equipment from Chapter [10.1], but also ideas described earlier in this Thesis will be used. Well X is not a real well, but a combination of several wells for demonstration purposes. The case constructed here is new compared to what has been performed before. The operation sequence is somewhat different, the well and the challenges are different. Barrier drawings and thought risks for this case are new.

15.1 History/Comments

The well X was drilled and completed in 1999. The well is an oil producer, but due to reservoir depletion and lack production and revenue it has been decided to permanent plug and abandonment the well.

There is not sufficient length above reservoir cap rock in the liner and casing shoe. There need to be minimum 50 m to act as a permanent barrier. Pressure gauge is installed at 3270 m MD.

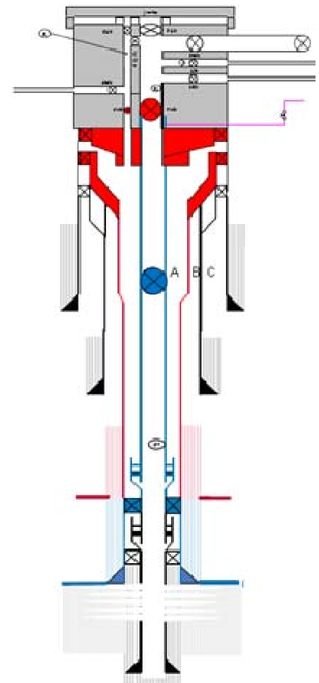


Figure 65 Well X

15.2 Equipment

Standard slick line and e-line will be used for the operations. Other equipment that will be used:
-Subsea: Well Control Package, Cement spool, Cement adapter tool, SSD, Jack, subsea pump, Tree cap
-In well: eRED plug [36] (able to open /close based on the pre-programmed pressure sequence), standard mechanical plug, Lego straddle [16] (straddle mounted on top of each other to be able to isolate a long section), Standard logging, punching and cutting equipment
-Fluids: Cement and water

Subsea equipment rig up A:
Vertical X-mas tree
RLWI stack (WCP, LS, PCH)

Subsea equipment rig up B:
Subsea Shutoff Device
Volume Control Device
Jack Mechanism

Subsea equipment rig up C:
Cement adapter tool (CAT)
RLWI stack (WCP, LS, PCH)

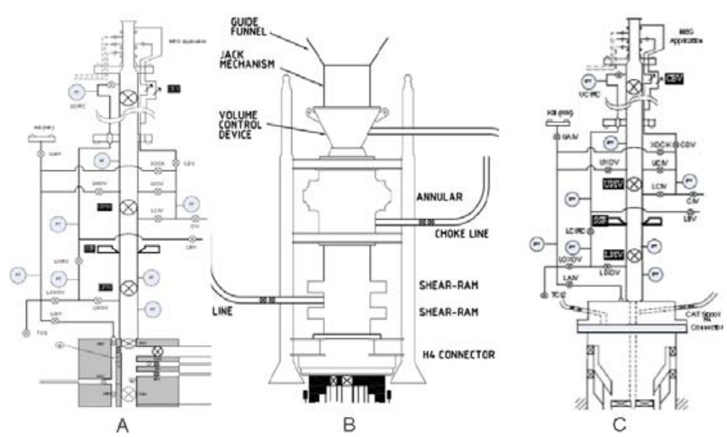


Figure 66 Drawings of subsea rig up A, B and C

15.3 Well Data

Table 14 Well data for Well X

KEY WELL DATA		
Well number	X	
Well type	Deviated	
Fluids in wellbore	Oil/gas/water	
Perforated	3504-3513 m MD	
DEPTH REFERENCES / VESSEL INFORMATION		
Intervention Unit	Vessel Y (RKB – MSL = 2.0 m)	
Water depth (MSL – Seabed)	300.0 m	
Height, seabed – WH datum	3.5 m	
Height, RKB – WH datum	299.5 m (Vessel Y)	
Height, RKB – Top VXT	297.0 m (Vessel Y)	
TEMPERATURE AND PRESSURE REGIME		
Bottom Hole Temperature	92°C	
Current SIWHP	47 bar	
Current SIBHP	241 ±10 bar	
Down-hole pressure gauge	Installed at 3270 m MD	
AVAILABLE LOGS		
Correlation log	GR and CCL log from 1999	
Cement log	**No cement logging performed for 9 5/8” casing.** **Cement log for 13 3/8” casing cement available.**	
PRODUCTION CHEMISTRY		
H2S [ppm]	2 ppm	
Scale (Ion data) and SW%	Possible	
Hydrate potential	High/medium	
COMPLETION DATA		
Fluids in annulus	Packer fluid 1,20 SG NaCl	
WELL INTEGRITY		
Well barrier status	Green	
Cement quality behind casing /liner	Full returns during cementing.	
Corrosion	Caliper from March 2010 showed no signs of corrosion.	
MAXIMUM DEVIATION		
Max. deviation	60° @ 3149 m MDRKB	
Deviation at top reservoir	50 @ 3504 m MDRKB	
Max. dogleg	3.3°/30 m @ 2380 m MDRKB	

15.4 Description of abandonment operations

In the column to left the WBS (Well Barrier schematic) is described the subsea equipment and the number of drawing. See Chapter (15.6) for WBS drawings during the P&A operation.

Op	Description	Comment/Reference	WBS
	Kill and secure well. Retrieve VXT (Temporary P&A)		
1	Transit to template, perform DP trials and receive handover. Open manifold hatch and retrieve tree cap to surface		
2	Deploy and establish well control package and lubricator section (Stack)		1A
3	Performed caliper run on WL	Identify the status of the tubing and verify plug setting area. Another alternative is to run a PLT with XY caliper with pressure / temperature log (to optimize cement job).	2A
4	Bullhead killing fluid into reservoir.	Bullhead fluid through kill hub in well control package. Recommend to test the injectivity in front of operation	1A
5	Install and pressure test a deep set mechanical plug at 3340 m MD	Install the plug: a) to guide the fluid when displacing tubing and annulus to heavy fluid b) fundament for cement barrier	2A
6	Punch tubing on WL Cut tubing on WL Displace tubing and annulus to brine	To create good communication between tubing and annulus Take return to flowline or a waste well	2A
7	Install a DHSV protection sleeve to hold the sleeve open.	There is no communications to the DHSV valve after the VXT is removed. To avoid problem in the well due to the DHSV flapper a sleeve is installed	2A
8	Install tubing hanger plug (with pump open plug) and annulus plug.	Pump open plug can be open or close with pressure following a pre-programmed set up. The stack needs to be reconfigured for annulus access. Mean; the stack has to be retrieved to surface on vessel for modifications, before deploying for further operations	
9	Retrieve stack to surface.	Barriers in well: Deep set plug and Tubing hanger plugs.	
10	Disconnect and retrieve Vertical X-mas Tree on main winch	If lack of deck space the VXT can be wet stored until operation is completed.	3

	Install Subsea Shutoff Device (SSD),volume control device, Jack		
11	Deploy and install SSD. Pressure test.		
12	Install fluid control system	Based upon the riserless dual gradient system	
13	Install the Jack	A Jack gives additional pulling forces and centralizes during retrieval of tubing.	
14	Close and test SSD SSR. Equalize and open pump open plug.	Open plug by pressure cycles through choke and kill line. Barriers deep set plug and SSD.	
15	Open SSD SSR with fluid system control established	Barriers deep set plug and fluid control. SSD as back up.	4B
16	Install THROT in place in SSD and close annular.	THROT is run on main winch. THROT is usually used to install tubing and tubing hanger (TH). THROT is used instead of THERT due to orientation system. Annular acts as an environmental seal around THROT in case of hydrocarbon below Tubing Hanger.	4B
17	Unseat tubing hanger and tubing with main winch or Jack mechanism. Verify tubing hanger unseated	Note: 1. In additional to tubing weight, the friction force of the tubing hanger sealing arrangement must be considered 2. Pull as vertical as possible to centralize The max lifting capacity of the main winch is 200 ton (double fall) and 250 ton with Jack. Do not lift with main winch and Jack simultaneously.	4B
18	Circulate out residual well fluids retained under tubing hanger and then open annular.		4B
	Lift tubing, perform logging and install barriers		
19	Lift tubing/tubing hanger and THROT 230 m.		4B
20	Run BHA with cement logging tool through tubing. Log the necessary window to verify the cement behind 9 5/8” casing.	For more information regarding logging of cement behind casing with tubing partly retrieved see Chapter (8.2) To use the 9 5/8” cement as Well Barrier	4B

		Element the cement need to be verified by logging. Depending on the result of the log, are the sufficient cement height to use or not: a. Necessary qualified cement behind 9 5/8" casing. Possible to pump primary and secondary barrier at once b. Only sufficient qualified cement for primary barrier, then install primary cement plug.	
21	Lower tubing into well with tubing. Stop 2 m over cut. Install float valve and test.	Float valve installed to prevent any influx flowing via tubing string to surface.	4B
22	Make up cement hose to THROT and close annulus.	Use Moffet stab or similar for subsea make-up. Divert returns to vessel via choke/kill line	4B
Alternative a) Sufficient cement behind 9 5/8" casing for both primary and secondary barriers			
23	Pump cement through tubing to create a required cement plug. After 2/3 part of the cement plug is disposed the tubing is retrieved above cement plug and circulate the pipe clean	Both primary and secondary barrier can be installed at once since the annulus barrier is verified and mechanical plug installed.	4B
Alternative b) Sufficient cement for only one barrier			
24	Pump required cement plug for one barrier. Same procedure as above.	Primary barrier.	4B
Retrieve tubing to surface. For both alternative a) and b)			
25	Open annular and Pull tubing, Tubing hanger and THROT on main winch to surface.		
26	Set tubing in slips on vessel		
27	-Disconnect cement hose, unlock and lay down THROT. -Make up Tubing Hanger Handling Tool, pick up hanger and reset slips. -Shear tubing above coupling by using tubing shear. - Lay down tubing hanger.		
28	-Pick up tubing with main winch and set slips at vessel. -Disconnect tubing joints. -Lay down tubing.	The tubing can be bundled as it is recovered. If lack of deck capacity the tubing can be wet stored.	

	-Repeat sequence as above until all tubing is recovered.		
29	-Shut in SSD. Cure and pressure test cement. -RIH with WL and tag top of cement. (TOC).		
Install secondary cement plug for alternative b).			
30	Set mechanical bridge plug at 2180 m MD to use as foundation for secondary barrier cement plug.		
31	-Retrieve SSD to surface -Install well control package (WCP) and CAT		
32	-RIH with selective perforation and perforate 9 5/8" casing at 2170 m MD (lower perforation). -Monitor wellhead and annulus pressure -Perforate 9 5/8" (upper perforation)		
33	-Set CAT stinger and inflate packer -Displace annulus to Brine to clean annulus. -Pump required height of cement plug -Hold pressure and wait on cement. -Pressure test cement. -Deflate packer and recover CAT stinger.	To isolate upper perforation and create circulation. See drawing in chapter (12.3.1) The annulus cement is supported by the fluid below the lower perforation.	
34	Run USIT/CBL to verify over displaced annulus cement. Tag TOC.		6C
Establish open hole to surface plug. For both alternative a) and b).			
35	Install mechanical plug at 600 m in 9 5/8" casing as foundation for open hole to surface plug.		5C/6C
36	Perforate 9 5/8" casing (lower perforation-just above foundation) and then perforate 100 m above.	Two perforations to make circulation path.	5C/6C
37	-Set CAT stinger and inflate packer. -Displace annulus fluid to seawater -Pump annulus cement plug. Wait on cement (WOC) to cure. Pressure test annulus cement.		5C/6C

	-Deflate packer and recover CAT stinger.		
38	Verify annulus barrier cement plug by running USIT/CBL log.		5C/6C
39	-Perforate 9 5/8" and 13 3/8" casing (lower perforation-through annulus cement). -Perforate 9 5/8" and 13 3/8" casing upper perforation).		5C/6C
40	-Set stinger and inflate packer. -Displace annulus fluid to sea water. -Pump balanced surface cement plug -Deflate packer and recover CAT stinger. -WOC, pressure test and tag TOC.		5C/6C
41	-Retrieve WCP with CAT to surface. -Install protection/debris cap		
Wellhead removal			
42	Use the Subsea Wellhead Picker to cut casing and retrieve the wellhead.	Subsea Wellhead Picker combines Internal Multistring Cutting tool based on Abrasive Water Jet Cutting tool.	
43	Final survey. Handover the well. Transit to shore and demobilize.		7/8

15.5 Risk identified

Below is some of the risk identified for the job “Description of abandonment operations”

Table 15 Risk identification

Hazard description	Consequence	Comments
Lack of communication between tubing and annulus after punching	No circulation. Punch higher up. Extra run.	Might be Black Sticky Stuff
Problem to cut the tubing in compression	Re-cut or change tool.	Some new tool are able to cut in compression
Not enough qualified cement behind 9 5/8”casing or problem to qualify the cement	Change in program. Delay.	
Not able to unseat tubing hanger	Problem to retrieve tubing to surface. Jack system will add additional forces	This can in worst case be a show stopper.
Hydro carbon trapped below tubing hanger	Spill to sea	Annular activated while unseating tubing hanger
Polish Bore Receptacle (PBR) loosen	Possible to retrieve the PBR with spear, but in the case above it makes some problem during logging and cementing	Need to check the DBR how the PBR was run during installation
Problem with control line when lifting and lowering tubing	Control line get stuck	
The mud recovery system fails	Loose volume control	Shut in well
Loss of barrier while cementing	Pull THROT and tubing hanger above SSD before cut	Might be problem to cut THROT and Tubing hanger
Contamination of cement during displacement	Poor cement job	Use spacers or wiper plugs

15.6 Well barrier schematic drawings during P&A operation

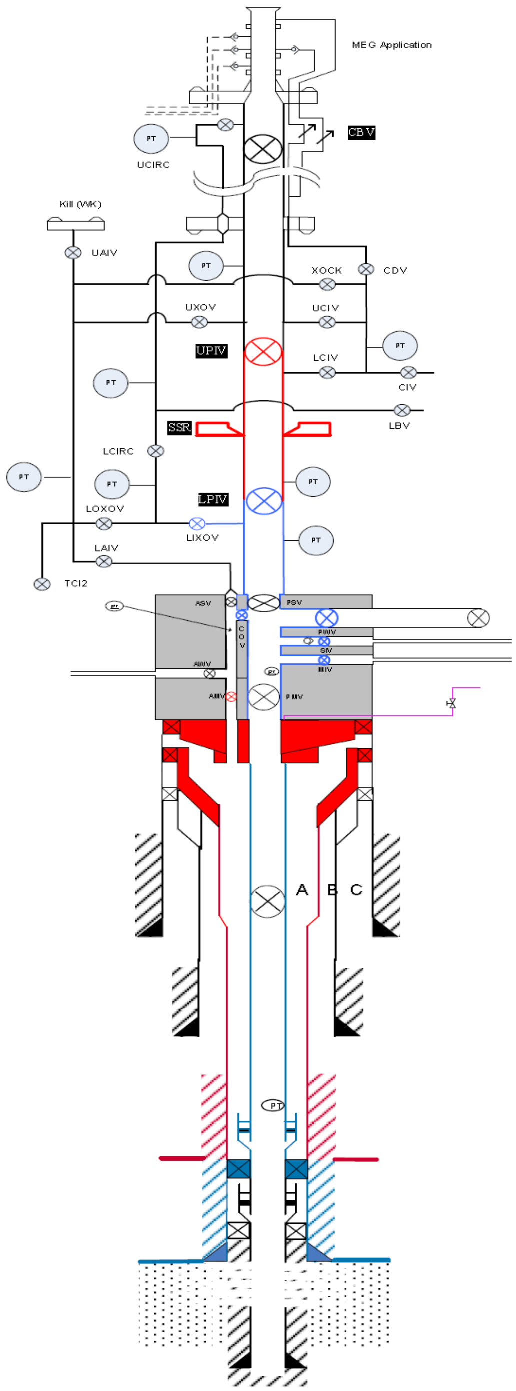


Figure 67 Stack on VXT-Out of well –1A

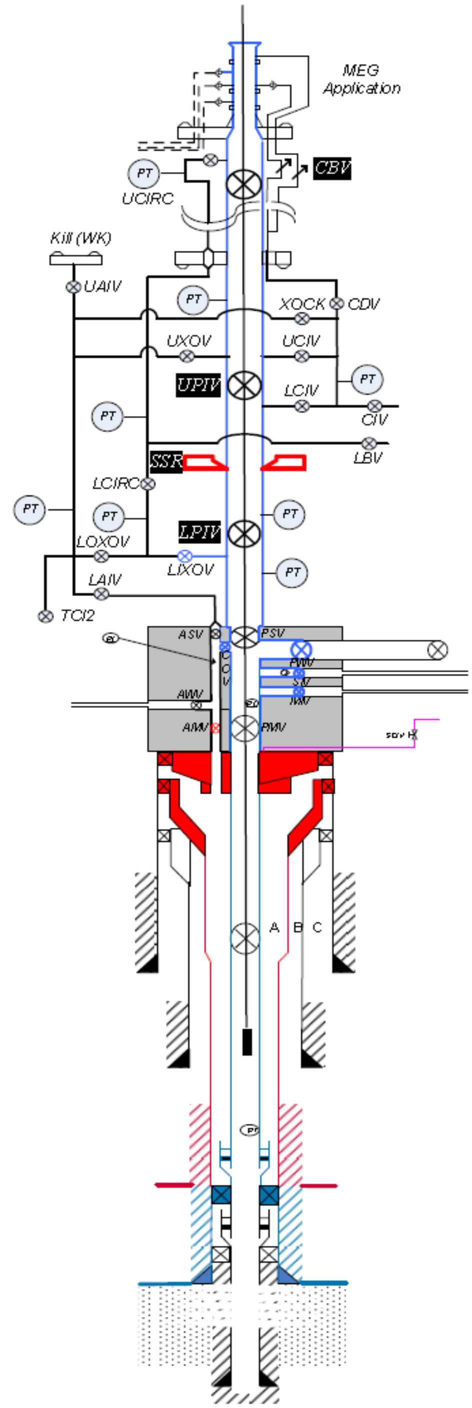


Figure 68 Stack on VXT-WL in well –2A

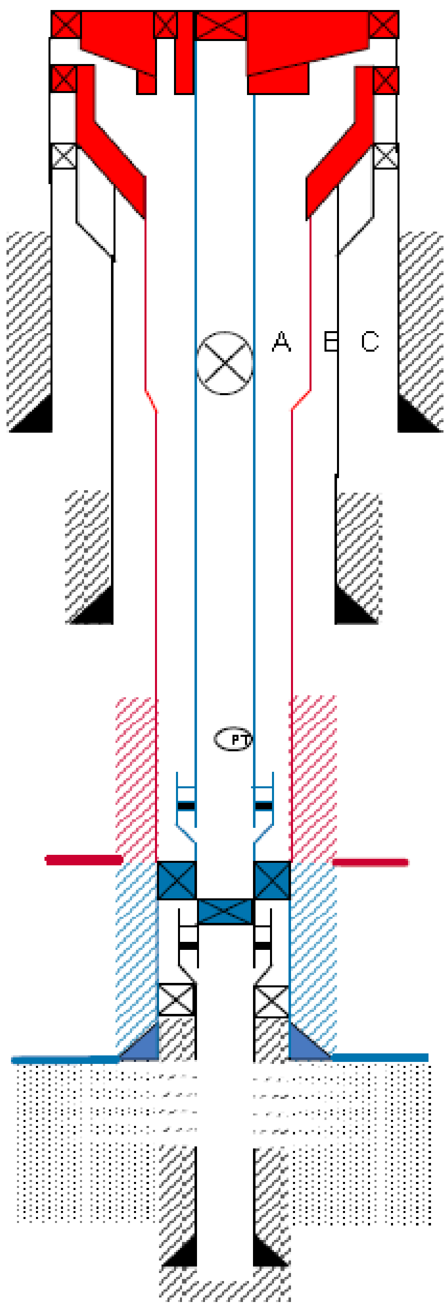


Figure 69 Stack and VXT are removed. Deep set and tubing hanger plugs are barriers- 3

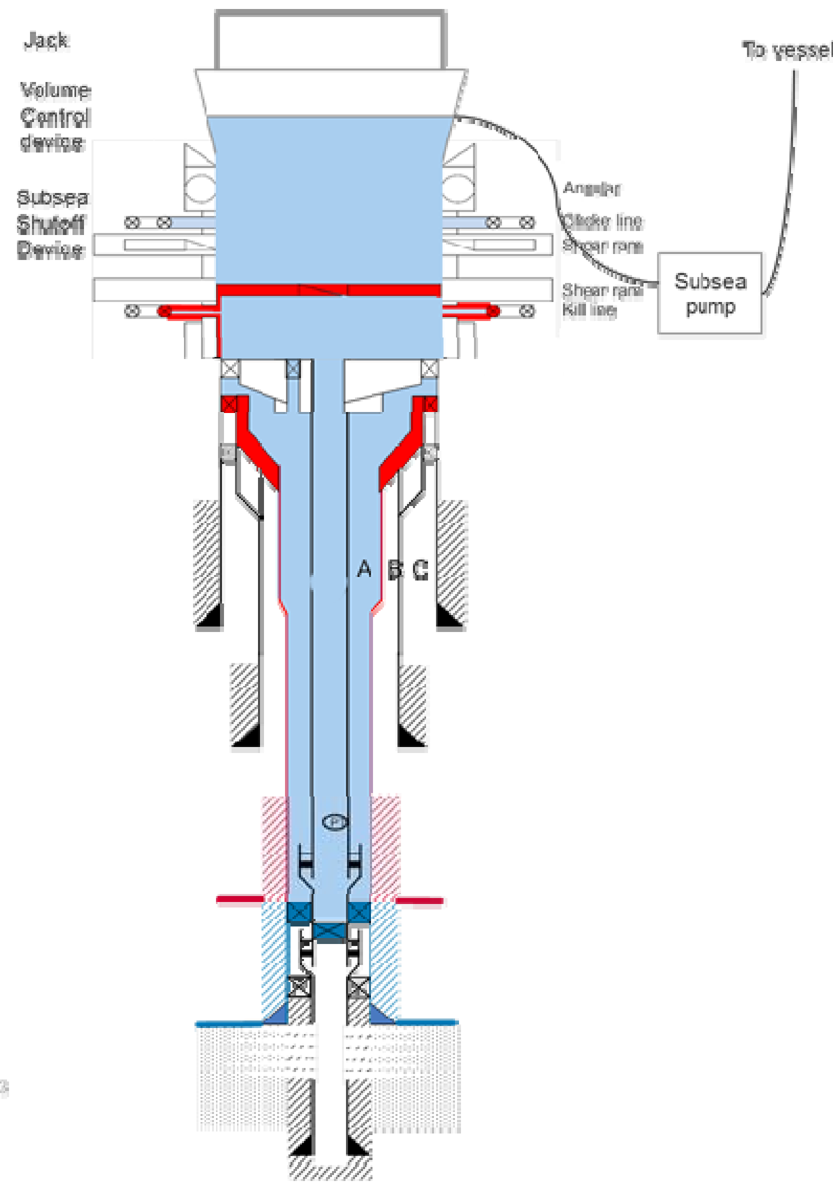


Figure 70 SSD, Fluid control, Jack-During cutting of tubing and cementing-4B

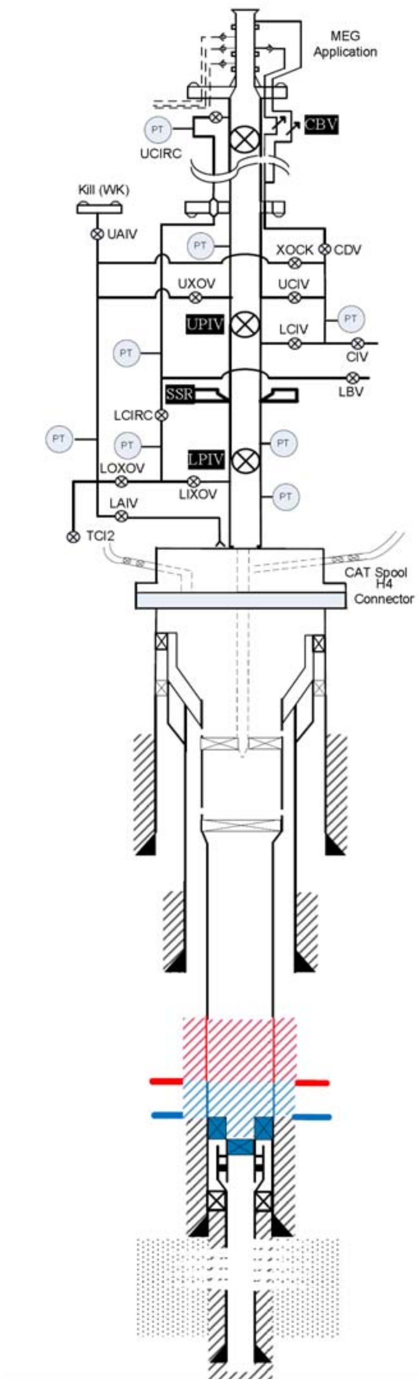


Figure 71 RLWI Stack and CAT installed- Common cement barrier for primary and secondary-5C

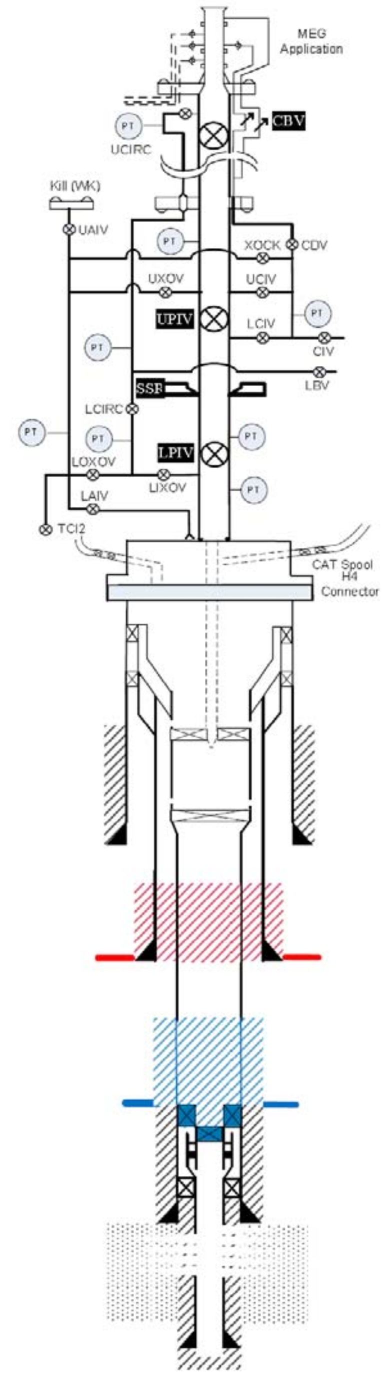


Figure 72 RLWI Stack and CAT installed- Not-common cemented barrier for primary and secondary-6C

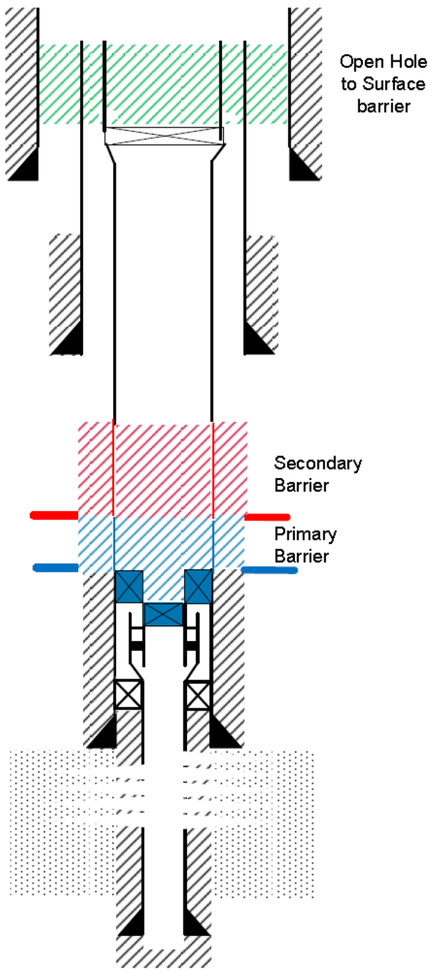


Figure 73 As Left drawing- Barriers in place-7

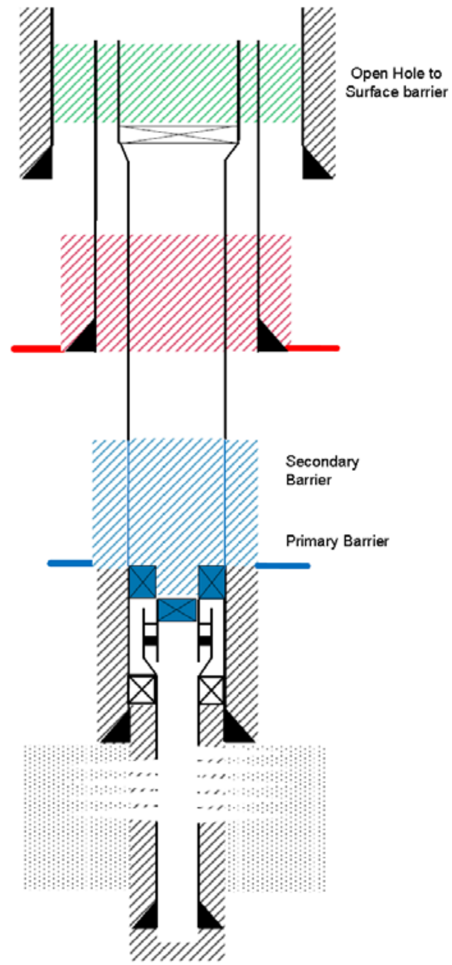


Figure 74 As Left drawing- Barriers in place-8

16 Analysis of weather and the behavior of semi-submersible rigs and RLWI vessels

As part of this Master Thesis an analysis has been carried out, with the respect to waiting on weather (WOW). WOW is a major time and cost item for operation for both semi-submersible rigs and RLWI vessels. The analysis in this Chapter will highlight the differences between RLWI vessel and semi-submersible rigs regarding WOW, operation time, and operation factor. It will also show WOW distribution an analysis which attempting to identify any relationship between the wave period and the wave direction and the effect on the heave in moonpool

Comparing the motion characteristics of RLWI vessel with semi-submersible rigs based on weather like wave height, period and wave direction, there are differences in the vessels movement with respect to heave, pitch and roll. The RLWI vessels have Dynamic Position (DP) and can align the vessels with wave direction to reduce the wave frequency motion. Semi-submersible rigs are usually anchored up during operation.

The motion is also totally different at the bow, beam or in the midship section of the RLWI vessel. The monohull is in the midship section of the RLWI vessel where the effect of heave is lowest.

When planning an intervention job with a RLWI vessel, a pre-determined WOW is added to the budget planning matrix. Around 50% extra hours waiting on weather is added to the budget in the winter season for the Statoil operations. There are also differences between the different RLWI vessels. The main reasons for the differences in WOW between the vessels are due to the difference in length, width and displacement of the vessels.

Operational limit and regularity are made for on handling of heavy equipment and Wireline operation in the moonpool.

1. The movement characteristics of the Intervention unit shall enable safe and efficient handling and stack-up, deployment and retrieval of subsea well intervention equipment in up to 4 (four) meters significant wave height.
2. The movement characteristics of the Intervention Unit in the moonpool area shall enable safe and efficient operation of the Well Intervention, in up to 6 (six) meters significant wave height.
3. The movement characteristics of the Intervention Unit shall enable safe and efficient launching and retrieval of the ROV unit, in up to 4 (four) meters significant wave height.

To be able to decide whether to continue with an operation or retrieve equipment to surface the operators are checking the weather forecast. For the LWI vessels for Statoil two independent weather suppliers are used.

Real time weather data is collected from Miros. Each platform or FPSO vessels have their own weather station onboard. The weather data is connected to Miros and is available to use for Statoil. Picture below is a snap shot from Miros.

Under normal operation the weather from Miros is added into DBR (Daily Drilling Report) every 6 (six) hours and while WOW the report frequency is increased to every 2 (two) hours.

Almost all data is from Miros except “Rig heave”, Rig roll deg” and Rig pitch deg”. The rig heave is heave in the moonpool on the vessel (where most of the equipment are deployed),“and roll and pitch are measured at the bow on the vessel.

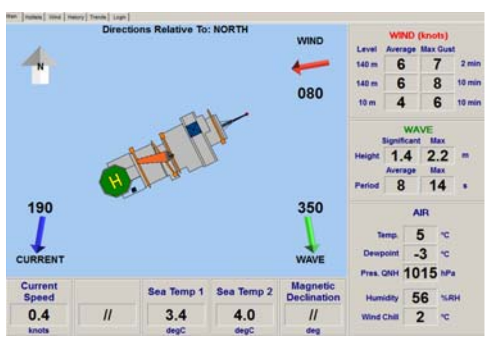


Figure 75 Weather info from Miros

Observation Time	Min / Max	Wind vel m/s	Wind dir deg	Air press mbar	Air temp degC	Sea temp degC	Sine wave height m	Wave period s	Wave dir deg	Sine swell height m	Swell period s	Swell dir deg	Rig heave m	Rig roll deg	Rig pitch deg
06:00		7,0	120,0	1013,0	0,0		1,4	7,0	250,0	2,2	12,0	250,0	2,2	0,7	1,0
12:00		10,0	120,0	1015,0	1,0		2,3	6,0	10,0	3,8	11,0	10,0	2,1	1,0	1,2
18:00		11,0	150,0	1016,0	0,0		2,1	6,0	10,0	3,3	11,0	10,0	1,8	0,8	1,4
00:00		9,0	160,0	1017,0	1,0		1,8	6,0	10,0	2,9	12,0	10,0	2,0	0,8	1,0

Figure 76 Weather presented in DBR

16.1 Compare operation time for semi-submersible rigs and RLWI vessel

The graph show operations time for semi-submersible rigs vs RLWI vessels in the period from Jan 2010 until April 2013.The total operation time is different for all semi-submersible rigs and RLWI vessels, some of the reason are:

- Some units is only for campaign contract for Statoil and has therefore less operation hours
- Some units has been on a "99" well (dummy for instance), due to 5 years classification for vessel and stack/BOP or major problem to equipment.

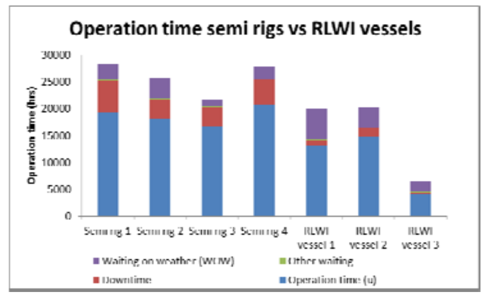


Figure 77 Operation time for semi-submersible rigs vs RLWI vessels

Operations factor is the percentages of a units working hours. It is the working hours +WOW hours divided at the total hours (working hours + WOW+ Downtime). By looking at the operation factors the RLWI vessels outperforms semi-submersible rigs.

The analysis indicates that RLWI vessels has more WOW compared to the semi-submersible rigs, but the total operational time (uptime) is just slightly better.

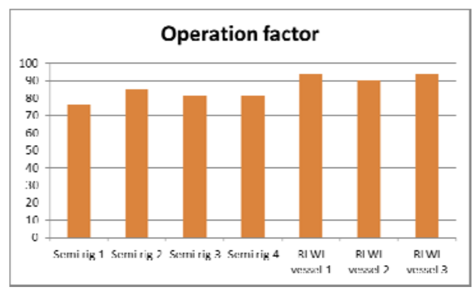


Figure 78 Operation factors for semi-submersible rigs and RLWI vessels

The analysis confirms seasons w.r.t and that, there are more WOW in Q1 and Q4 compared to Q2 and Q3. But is also shows that there are big differences between the different years.

Note that when RLWI operation first started, the first years operation was only performed in the summer time, RLWI operation today is premised during the entire year.

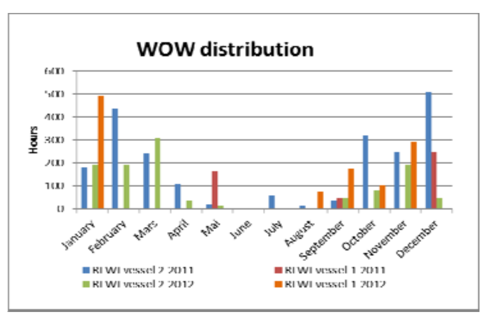


Figure 79 Distribution of WOW for RLWI vessels. Year 2011 and 2012

16.2 Analysis of the effect of the period,significant wave height and wave direction

An analysis was performed to identify any relationship between wave period and the wave direction and the effect of the heave in moonpool.

As part of the Thesis, the following results have been worked out.

Figure 80: Period vs heave in moonpool. Indicates that longer period give more heave in moonpool. This is due to the fact that the RLWI vessel not will ride the waves, but follow the top and bottom of the wave when the period exceeding a certain period.

Figure 81: Wave direction vs heave in moonpool: Indicates that more exist more down time when the waves direction is coming from North and West(+/-), which correlates to wind direction in Q1 and Q4.

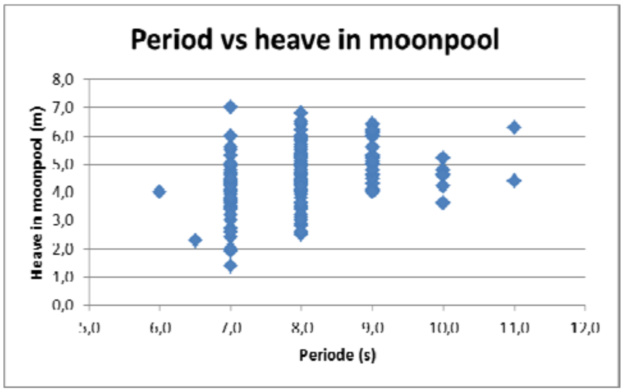


Figure 80 Distribution effect of period vs heave in moonpool

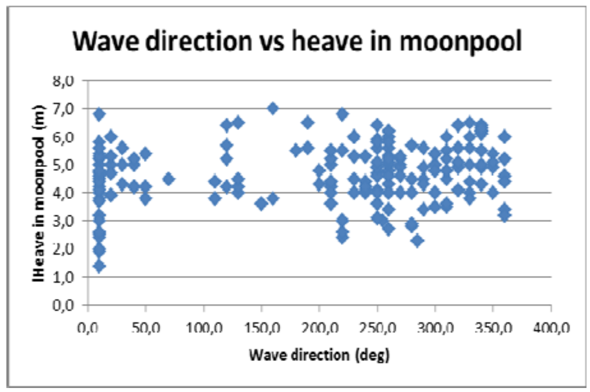


Figure 81 Distribution of wave direction vs heave in moonpool

17 Cost and benefits

The day rate of a RLWI vessel is significantly lower than an ordinary rig, and performing the entire or part of the P&A operation can achieve cost savings. The total cost picture is not covered alone with the day rate of the unit. The vessel/rig availability, weather limitation, P&A method, need for retrieving of tubular to surface and ability to perform operations in batches should also be considered.

Unit availability: Not sufficient conventional rigs available in the market.
Weather limitation: Bad weather can result in well operations be of excessive length and cost factor for the oil companies.

17.1 Batch operation on the same template

While planning to plug and abandonment several wells in the same template or nearby it is possible to perform the P&A in batches to increase the safety (to avoid changing stack from mainbore access to annulus access several times), and increase the efficiency and therefore save money. Statoil did batch operation on temporary P&A on TOGI and planning to do batch operation for temporary P&A for Glitne with a RLWI vessel. It is also possible to perform wellhead cutting in batch.

Figure 82 Island Wellserver and TOGI XMTs [28]

17.2 Batch operation with different vessels

Another batch possibility is to split operation between two vessels in e.g 2 phases. This will increase the efficiency and thereby reduce the cost significantly. Phase 1 will then be from a “traditional” RLWI vessel, performing standard wireline jobs and using existing well control package. A specialized vessel will do phase 2, which could include releasing of tubing hanger and retrieving of tubing with specialized P&A equipment onboard.

17.3 Time and Cost Estimate

To compare the semi-submersible rigs and RLWI vessels in more detail, an estimated time distribution for a P&A operation has been performed. The time estimate is based on the example in Chapter (15) with alternative B where primary and secondary barrier is not common. The operation will be performed in the summer season. Mobilization will be performed onshore for RLWI vessel and offshore for semi-submersible rigs. The mobilization for semi-submersible rigs will mainly be performed parallel to other activities.

Based on operation time in DBR, the average handling of BHA is 4 hours more for each run for a RLWI vessel compared to semi-submersible rig. The time spent on RIH, POOH and operation in well is similar for both units. In the time estimate it is assumed that the rig moves between two fields that are fairly close.

Table 16 Time estimate for Well X

RLWI vessel	RLWI vessel	Semi rig	Semi rig
Operation	Estimated time	Operation	Estimated time
Mobilize equipment. Transit to template, DP trials	50	Mobilize subsea equipment. Move and position rig	20
Open hatch and pull TC	13	Open hatch and pull TC	13
Run RLWI stack and connect to VXT. Install kill hose	34	Run WOR stack and connect to VXT	57
Performed Caliper run	22	Performed Caliper run	18
Kill well	10	Kill well	10
Install and test deep set plug	18	Install and test deep set plug	14
Punch and cut tubing (2 WL runs)	36	Punch and cut tubing (2 WL runs)	28
Displace tubing and annulus to brine. Retrieve kill hose.	20	Displace tubing and annulus to brine	8
Install DHSV protection sleeve	10	Install DHSV protection sleeve	8
Install TH plug in production and annulus bore. The stack has to be retrieved to surface to modify for annulus access and before pull VXT	80	Install TH plugs (two run)	16
Pull VXT to surface	15	Pull VXT on WOR to surface	40
Install SSD, volume control system, and Jack	35	Install BOP and marine riser	35
Pump open and retrieve TH production bore plug	10	Pump open TH production bore plug	2
Deploy THRT and lift tubing and tubing hanger	8	Prepare and pull TH and 5 ½” tbg	45
Run cement log through 5 ½” tubing	25	Run USIT	14
Plug and abandon well. Establish primary barrier in 9 5/8".	30	Plug and abandon well. Establish primary barrier in 9 5/8" casing	50
Pull TH and 5 ½” tbg to surface	45	Plug and abandon well. Establish secondary barrier with perf and wash method in 13 3/8"	50
Install mechanical plug as foundation for secondary barrier	16	Establish open hole to surface plug (retrieve casing)	44
Retrieve SSD, volume control system, and Jack to surface	30	Pull MR and BOP	13
Install RLWI stack and CAT	20	Cut and retrieve wellhead	12
Establish secondary barrier in 13 3/8" casing	72	Demobilize and pull anchors	15
Establish open hole to surface barrier with use of CAT.	110		
Retrieve RLWI stack and CAT.	20		
Cut and retrieve wellhead	12		
Transit to shore and demobilize	20		
Total [hours]	**761**		**512**
Total [days]	**31,7**		**21,3**

In this time estimate the semi-submersible rig spend only 67 % of the time that a RLWI vessel used to complete the operation.

Each well is unique and need different methods to reach goal. The time estimate is just an estimate for the well X with alternative B. Here are some of the factors that can affect a time estimate;

- Different depth in well
- High well inclination and need of tractor
- Placement of cement barrier, separately or common
- Do it exist verified barrier logs?
- Is it a well with multiple formations? then need extra barriers
- Is it any equipment or methods that are more enhanced to use?
- Will the job be performed in the winter or summer time?
- Can the job be performed in batches?
- Logistic, place on deck

All this should be taken into consideration while make the time estimate.

There will be investment cost regarding new optimized equipment to perform P&A operation on RLWI vessel. The cost contain, pipe handling system jack, Subsea Shutoff Device, Volume control and tubing hanger release tool. Coiled tubing will be an additional investment cost if that will be implemented. Several wells completed with the new plug and abandonment equipment with RLWI vessel causes lower cost of the items per well.

The benefit of using RLWI vessel compared to semi-submersible rigs is not straight forward. The last chapters have described some of the relevant factors that affect the total time and cost picture: Operation factor, the weather, available equipment, P&A methods, and possibility to perform batch operations.

The estimated cost of a RLWI vessel is 40-50% less than for a semi-submersible rig, but the investment in new P&A equipment will increase the cost for the vessel. The time estimate show that a semi-submersible rig could be able to spend 67% of the time RLWI vessel use to complete the operation. But one of the main benefits is that the semi-submersible rigs are available to drill well.

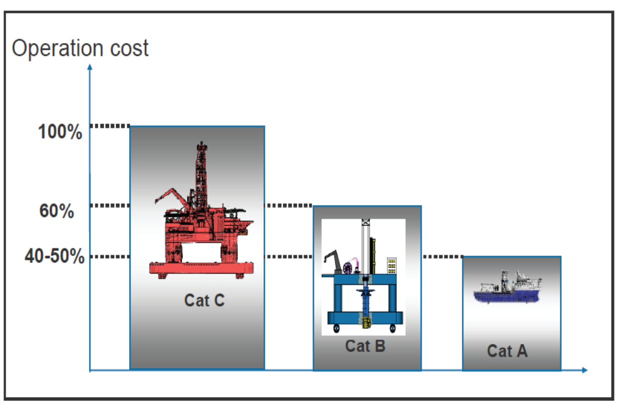


Figure 83 Illustrate the operation cost per category [47]

18 Discussions and Conclusion

18.1 Discussions

The historical and present P&A technology and requirements for subsea wells are linked to use of semi-submersible- rigs. P&A will likely attract more focus in years to come as a demanding number of subsea wells will need to be properly and permanently P&A'ed in years to come.

The traditional P&A method should be challenged.

Currently, the operations performed on RLWI vessels are standard wireline operation and pumping operation (through a kill line). So far there have not been any Coiled Tubing operations performed from RLWI vessel.

The main challenges for plug and abandonment operations using a RLWI vessel are related to

- Logging of the well
- Cutting of tubing and control lines
- Different approaches for removing of tubing
- Coiled tubing operation without riser
- Challenges regarding installation of barriers

<u>Logging Challenges</u>

There are several logging challenges for plug and abandonment operations. There are requirements stating that permanent well barriers

- Shall extend across the full cross section of the well
- The cement needs to be verified.
- Control cables and lines shall be removed from areas where permanent well barriers are installed (since they may create vertical leak paths through the well barrier)

Based on the above three main logging issues can be addressed:

A. *Cement bond logging through multiple tubular*: Cement bond logging through multiple casing strings achieve hopefully a sufficient solution is near future. When this logging challenge is achieved the need for tubing and casing removing are reduced.

B. *Log cement behind casing with tubing partly retrieved.* It is possible to log the cement behind 9 5/8" casing before the new cement barrier plug is in place and before the tubing is retrieved to surface. Sufficient length of tubing needs to be lifted in front of the logging operations. The logging will be performed after the tools has been run through 5 ½" tubing. The recommendation is to only use USIT/Isolation Scanner without using Sonic CBL, due to the possibility to centralize. There is no available centralizers and sonic tool design which could fit into tubing and maintain good centralization in casing afterwards. It is preferred to log in Brine.

Another alternative is to log SSL (slim sonics) eccentric using standoff if the well is deviated in the area of logging, and an exemption from standard logging procedure need to be made.

C. *Identify control lines behind tubing*: There are possibilities today to identify the control line clamps behind the tubing. By managing to identify the clamps it is possible to know where the control lines are. By use of this technology it is possible to cut tubing and control lines at once.

Removal of tubing and control lines

Statoil has great expectations for the new cutting devices from Baker Hughes and Welltec. Some testing and qualification still remains before the tools are qualified for cutting of tubing and control lines simultaneously.

In the future the control line cutting sub device should be installed during completion phase looking ahead to the P&A phase. Some reasons for not installing the control line sub might be that the completion engineer does not see the need for such installation, either due to increased cost or fear of cutting the control lines during installation.

The other methods are interesting, but need further refinement and technology improvement before they can be qualified and ready to be used in the field.

Different approaches for removal of tubing

Removal of tubing has been split into two focus areas;

- first section includes retrieval of tubing to surface including subsea equipment to be used
- the second section includes alternative solutions for downhole removal of tubing, e.g not retrieval of tubing to surface.
    - Remove only necessary tubing by pushing tubing down by crushing tubing
    - Use of chemicals to remove the tubing
    - Melting of the tubing

For all operations, minimum two barriers need to be in place at all times. When retrieve the tubing to the surface, additional equipment and systems have to be established;

- Subsea shutoff device
- Volume control system
- Jack mechanism
- Tubing Hanger retrieving equipment
- Pipe handling equipment (on surface).

Separately, the technology is field proven for every item above, but the equipment have never been used in this combination. It is possible to centralize the tubing with Jack and annular.

The main winch will retrieve the tubing to surface, but in some cases extra pulling forces is necessary during unseat of the tubing hanger. The Jack mechanism can be used.

Another method for removal of tubing includes pushing of the tubing down by crushing the tubing. This is an interesting concept, which also eliminates the need for tubing handling at the surface. This procedure makes it possible to use standard RLWI stack as barrier during operation.

Tubing removal using chemicals is likely time consuming operation. It is not recommended to displace the chemical into tubing and annulus, due to the danger of destroying other equipment while the chemicals reacting with the various well components. The chemical reaction can take place before reaching the target. It is recommended to use either; Coiled Tubing or wireline equipment to place the chemical at correct depth.

Remove tubing by melting is an innovative idea. It is possible to cut the tubing by melting. However, further refinement is necessary to improve the technology before it becomes an alternative way of removing tubing.

Coiled Tubing operations without riser

If concepts to perform Coiled Tubing operations from RLWI vessels can be realized, then it should be possible to extend the scope for P&A operations compared to wireline solutions. With implemented Coiled Tubing on a RLWI vessel several operations alternatives opens up; such as well clean up, cutting of tubing with abrasives and placement of cement barriers will improve. Thus implementation of Coiled Tubing from RWLI vessels will complement the already proven and standard wireline operation. Challenges with respect to use of wireline reaching high angle and deep wells may be reduced.

The necessary set up of well barriers during Coiled Tubing operations from a RLWI vessel have not been defined, but the future barrier system will likely be based on the existing subsea intervention system with some expected modifications. The "Open water coil tubing" concept will use three injectors to achieve necessary control of movement of the Coiled Tubing and to avoid destroying the Coiled Tubing. There are several methods to achieve the circulation back to surface.

The RLWI vessel #2 that currently are under contract for Statoil will lack deck space if Coiled Tubing is established on the vessel, but additional mezzanine deck is possible to install according to Island Offshore.

It might be important to differentiate between RLWI vessel that perform P&A operations and standard wireline operations. Coiled Tubing options from RLWI will probably have more chance of succeeding in P&A scenarios, due to possibility to clean out well, place the cement barriers and pump abrasives.

The challenges regarding use of Coiled Tubing on a monohull vessel has been due to handling of equipment (risk for personnel), fatigue issue (both riser and Coiled Tubing) and handling of return with barriers in place. Island Offshore claims that they have overcome those challenges and are ready to use Coiled Tubing on a monohull RLWI vessel.

Different approaches for installation of barriers

There are different approaches for installation of cement barriers from RLWI vessels. It depends on whether Coiled Tubing (CT) is installed or not.

If CT is not implemented on the vessel, it is possible to pump cement for cement barrier plug:

A. Through Stack
B. Use of cement spool
C. Use of cut tubing
D. Casing Adapter Tool (CAT)
E. Well Abandonment Straddle Packer (WASP)
F. Suspended Well Abandonment Tool (SWAT)

The Cement Adapter tool (CAT) is able to establish primary, secondary and open hole to surface barrier. The CAT will be run together with a standard RLWI stack. There is no experience with use of CAT.

SWAT and WASP tool have long experience on establishing open hole to surface barrier on UK sector. The cementing devices are run without RLWI stack. It is necessary to use RLWI stack simultaneously as the cement device to obtain sufficient barriers control throughout the operation when the primary and secondary barriers are not established.

When Coiled Tubing is available, further options are available.

If Coiled Tubing is available on the vessel, the coiled tubing can be used to install and place the cement barrier in the reservoir or establish a cement plug in the casing when cement outside the casing is verified.

Statoil does have good experience from semi-submersible rigs using "Perforate, wash and squeeze techniques" from HydraWell and "Perforate and Wash" from Archer. Both system are run on drillpipe, the systems perforate, wash and place the cement to establish cement barrier. HydraWell and ConocoPhillips have in co-operation developed a system for P&A of multiple casing strings called the HydraHemera™. The differences between standard HydraWash™ tool and HydraHemera™ are:

- Bigger and denser perforation guns
- Wash sub with high pressure nozzle
- Create a base for cementing in multiple annuli

The abrasive cutter has no limit on max section length to be cut, and this is a benefit compared to other. The abrasive cutter is able to cut control lines, demonstrated on test. After the casing is cut, cement barrier is possible to establish.

The casing integrity system is use of thin coiled tubing. The technology is basically designed to repair B annulus on platform.

Well Barrier material

Only cement and formation are qualified as permanent plug barrier for Statoil. The nature's own barrier gives significant reduction in rig time and thereby saving operational cost as well as, improvement in the quality of well integrity. The formation can be qualified as a barrier element after sufficient logging and pressure testing result, but cement jobs always need to be planned as a back-up solution.

There is not a sufficient qualified test procedure to be able to qualify new permanent plug barriers to be accepted on the marked. Such qualifications test should be made in cooperation by oil companies, suppliers and authorities on NCS.

Comments regarding a full P&A on well X with a RLWI vessel

A procedure has been written in this Thesis to demonstrate some of the equipment and tools in use. Such as logging through tubing, place cement through cut tubing, place cement barrier with cement adapter tool and use Subsea Wellhead Picker to cut casing and retrieve the wellhead.

There are some extra risks identified when using cut tubing for cementing especially when PBR and control lines are installed in the completion. On well X it was not possible due install primary barrier in the reservoir due to there was not sufficient length above reservoir cap rock in the liner and casing shoe. There need to be minimum 50 m to act as a permanent barrier.

It is recommended to install the primary barrier in the reservoir and a mechanical plug above. This to obtain an extra barrier throughout the operation while retrieving the tubing. The barriers are primary cement barrier, mechanical plug and overbalanced fluid (with volume control).

If Coiled Tubing had been implemented in operation on Well X, more of the suggested ideas could be implemented.

Many of the Statoil wells penetrate more than one reservoir. Extra barrier need then to be establishing according to the requirements.

Weather analysis

A weather analysis has been performed identifying the differences in operation time and operation factors for RLWI vessels and semi-submersible rigs. The analysis indicates that RLWI vessels has more WOW compared to the semi-submersible rigs, but the total operational time (uptime) is just slightly better An analysis regarding the downtime for RLWI vessel #2 was also performed to identify the vessels behavior with different period, and wave direction and the impact on the heave in moonpool.

Cost and benefits

The cost of a P&A operation using RLWI vessel will be reduced compared with various rigs. This is mainly due to the day rate being approximately 50% for a RLWI vessel compared to a semi- submersible rig.

A time estimate was created to compare the time used to finalize the P&A operation on Well X. As described there are many factors that affect the time estimate.

GAPs that are identified during the thesis to complete the final P&A operation with a RLWI vessel:

- Log Cement through two tubular; Different logging systems are under development and testing. Other methods might be qualified to be used instead.
- THROT is not shearable; During 2013 a new version of THROT will be introduced to the market. This new THROT will be shearable.

18.2 Conclusion

This Master Thesis has described technologies and technology GAPs to perform the final plug and abandonment jobs performed from RLWI vessels. Today the P&A operations on subsea wells are performed from semi-submersible rigs. Semi-Submersible rigs are able to perform entire P&A jobs due to the possibilities to cut and retrieve tubing and casing to the surface. As showed in the Thesis, RLWI vessels will likely be able to perform the P&A operation to a lower cost even if the RLWI vessel spend more time to perform the operation.

The focus on plug and abandonment has increased during the last years. The requirement in NORSOK D-10 and internally within Statoil is continuously being challenged. However, P&A operations should in the future be an important part of the well planning and well construction phase.

New equipment, new methods or change in regulation may also result in significant changes in terms of P&A operations. The oil companies should staff the organization and allocate resources for Research and Development (R&D) for this increasingly focus area in years to come.

There is currently a global shortage on drilling rigs, and it seems that there will be shortage on semi-submersible rigs on the N.C.S in foreseeable time ahead. By developing technology and modify regulations to allow P&A for the increasing number of subsea well to be performed by RLWI vessels, the semi-submersible rigs can be prioritized for drilling production well and thus increase the oil companies revenue, while RLWI vessels supplement the P&A operations.

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20 Appendix

App A Expected cease of production and amount of wells necessary to be plug and abandoned

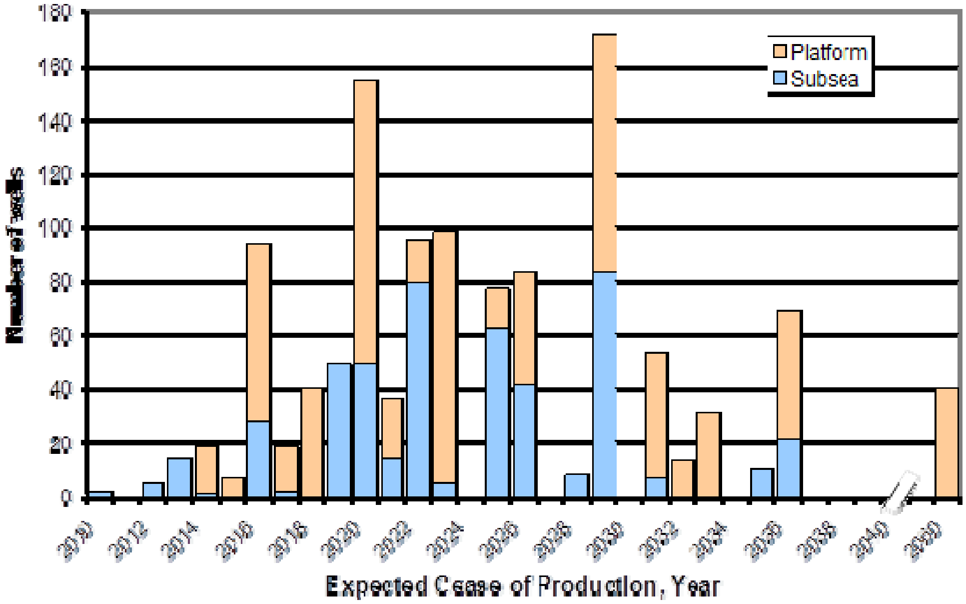


Figure 84 Expected cease of production of Statoil wells for existing fields on the Norwegian Continental Shelf [56]

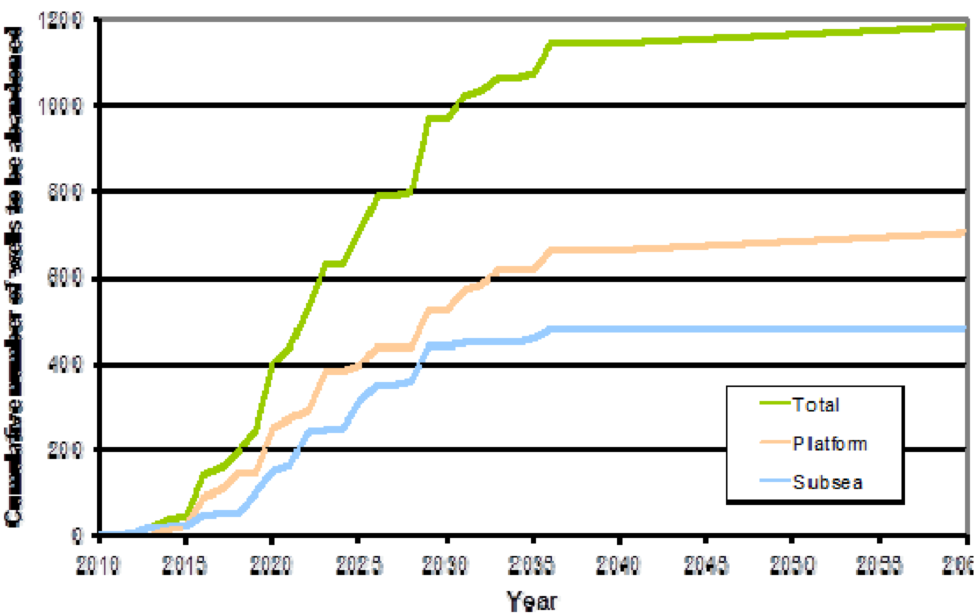


Figure 85 Cumulative number of Statoil wells necessary to plug and abandonment due to cease of production on the Norwegian Continental Shelf [56]

App B RLWI History

MSV Seawell (2000 & 2004 - 2005)

MSV Regalia (2003)

Island Frontier 2006-2013

Island Wellserver 2009-2013

Island Constructor 2012-2013

Figure 86 Pictures of units used in the RLWI history for Statoil [62]

App C Pictures from RLWI vessel

Figure 87 Pictures from RLWI vessel [28]

App D Suggested of Coiled Tubing equipment on Island Constructor

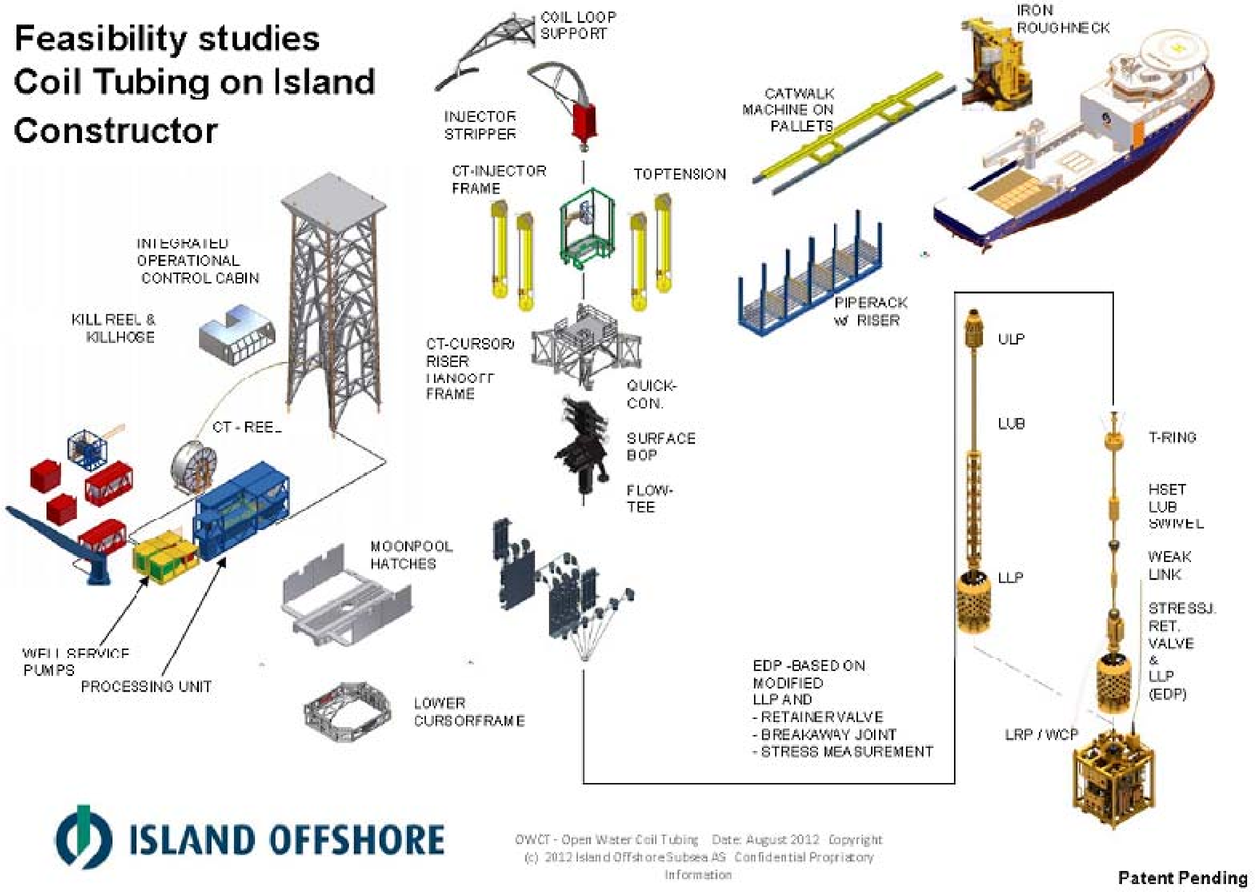


Figure 88 SuggestedCoiled Tubing equipment on Island Constructor [27]

App E Open Water Coil Tubing –Running illustration

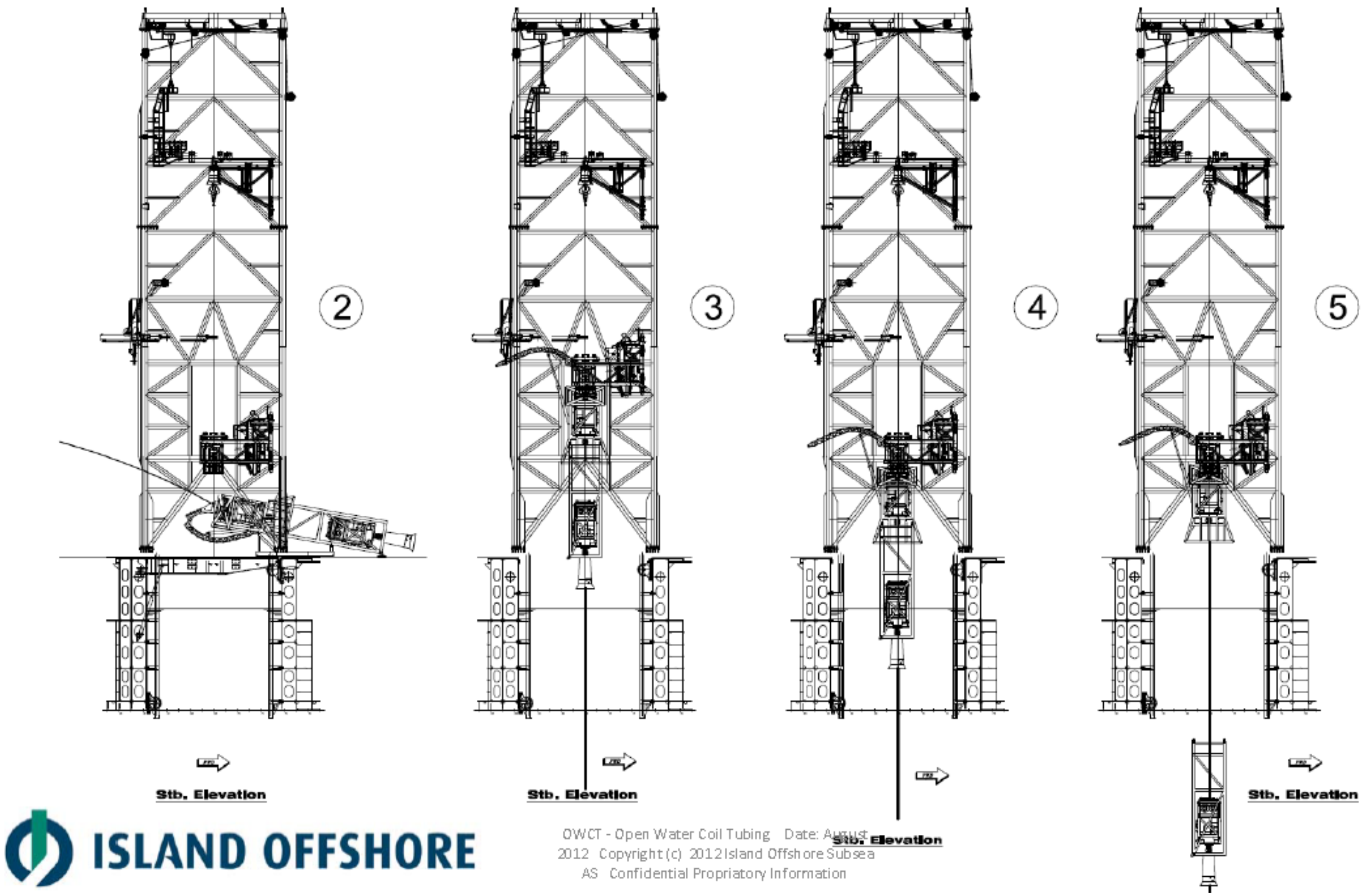
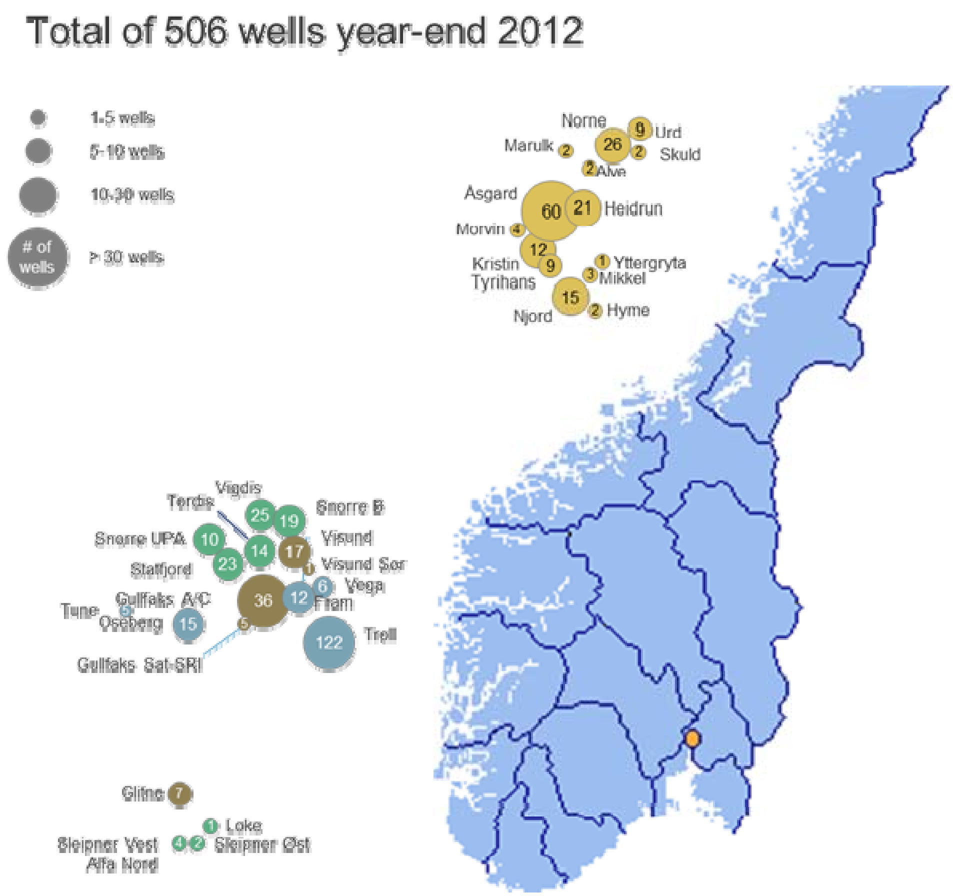


Figure 89 Running illustration for Open Water Coil Tubing [24]

App F Overview of Statoil subsea wells



Troll	122
Åsgard	60
Gullfaks	41
Snorre	29
Norne	26
Vigdis	25
Heidrun	21
Visund	18
Njord	15
Oseberg	15
Tordis	14
Kristin	12
Fram	12
Statfjord Øst	11
Statfjord Nord	10
Snøhvit	10
Urd	9
Tyrihans	9
Sleipner	7
Glitne	7
Vega	6
Tune	5
Morvin	4
Sygna	4
Mikkel	3
Hyme	2
Alve	2
Skuld	2
Marulk	2
Statfjord	2
Yttergryta	1

Figure 90 Overview of Statoil Subsea wells [48]

App G Cutting Tubulars with Wireline

There are several types of cutting device that can be used for PP&A purposes with wireline. There are explosive Cutter, Split-shot, Plasma Cutter, and Electrical mechanical cutting tool. All cutting device in this Chapter can be run with mono cable, e-line. There is no need for tractor to operate the cutting tool.

A. Explosive Cutters

Explosive cutters work on the same principle as a shaped charge for perforating. The major difference is that the cutter is a circumferential device and sends out a radial 360° explosive jet. This type of cutter will, under ideal conditions, leave a smooth-cut pipe with some degree of swelling at the point of the cut. Explosive cutters are designed so that when the correct size is selected, they can be used to separate pipe without damaging the outer casing or tubing string.

JRC Jet Cutter from Halliburton:

JRC Jet Cutter can cut from 1" coiled tubing up to 9 5/8" Casing. Cut pipe with explosives (Shaped charge). The cutter can operate in fluid and gas environments at up to 20,000 psi and over 400F.
Advantages:

- Clean cut
- Cuts without need of overpull on the tubing
- Cheap compared to electric mechanical tool

Dis-advantages:

- Sensitive to ID restrictions
- The shape of the cut is similar to a trumpet.
- Need to dress top of cut before installing a new cut (not for P&A purpose)

Figure 91 Cut performed with JRC Jet Cutter [15]

Power Cutter from Schlumberger:

The power cutter is designed to cut sizes of tubing from 2 3/8" to 7". Cut pipe with explosives (Shaped charge). Performs under pressure in 400 deg F and 18 000 psi wells

Advantages:

- Cuts without any need of overpull on the tubing
- Makes a clean cut
- Cheap compare to electric mechanical tool

Dis-advantages:

- The shape of the cut is similar to a trumpet.
- Leave steel pieces in well

Figure 92 Cut performed with Power Cutter [49]

–

B. Splitshot from Hallburton

The Splitshot split the pipe/collar longitudinally

Tool size: OD 1 3/8” and 2”
Advantages:
- Can be run through small restrictions and cut in larger ID.

Dis-advantages:
- Problems to cut VAM ACE threads

Figure 93 Tubing recovered with splitshot [15]

C. Plasma Cutter

The Plasma Cutter cuts the tubing when the Thermal Generator ignites and activates the primary fuel load; highly energized plasma is produced causing an increase in internal pressure. Once the pressure produced by the torch exceeds that of the well bore, the protective sleeve is displaced exposing the nozzle to the well bore. The highly energized plasma is diverted 90° thru the nozzle to sever the target in drilling, completion or production scenarios, with well bore temperature up to 500° F(260°C) and pressures to 20,000 psi (137.8 MPa).

RCT Radial Cutting Torch from MCR Oil Tools operated by Halliburton and Aker Well Service

RCT uses to cut tubing, casing and some sizes of drillpipe by melting. All types of steel can be cut up to 9 5/8”. Temperatures up to 500° F(260°C) and pressures to 20,000 psi (137.8 MPa). RCT need to be centralized in the well before cutting

Advantages:
- Very clean cut with no pipe swelling.
- No need for dressing of tubing before installing new tubing (Not for P&A)
- No damage to the casing outside the cut
- The tool are non-explosive

Dis-advantages:
- Tubular has to be perforated with a puncher gun before cut if well has a barrier / plug within 100 meters from the cutting area).Tubing Puncher is designed primarily for annulus circulation purposes
- Meltet steel. Problem to come free with BHA after activation.

Figure 94 Cut performed with Plasma Cutter [49]

D. Electrical Mechanical Cutting tool

The blade is rotating / cutting towards the wall with high rpm until the tubing is fully cut.

DECT Downhole eletric cutting tool from Aker Well Services [1]:
There are two sizes of Electrical tubing cutters 2 ¾" and 3 ¼"

- 2 ¾" head cut tubing size 2,99"-5,1"
- 3 ¼" head cut tubing size 3,5"-6,1" (with extension)
- Two centralisers are required for horizontal wells

Utilize rotating knive to cut tubular. Cutting operations are monitored at the surface for blade advancement, power & cutting noise level.
Temperature rating 150°C. Takes some minutes to cut through tubing
Advantages:

- No need for dangerous chemicals or explosives
- Clean cut
- Multiple cuts during single run, saving hours of time.

Dis-advantages

- Problem to cut in compression. The cutter blade can get stuck and broke.

Figure 95 DECT [1]

Figure 96 DECT tool anchoring system and ESP Packer Mandrel after cut [1]

MPC Mechanical Pipe Cutter from Baker Hughes:

The MPC can cut drillpipe, tubing, and casing from standard steel to super alloys.
Able to cut pipes size from 2 7/8" to 7" with a blade that rotate. It is possible to perform precise downhole cutting of tubing, without damaging external tubular. Cutting penetration is continuously measured and controlled, confirming the cut has been made and avoiding damage to external tubular or control lines. The MPC use normally 30-60 min to cut through tubing. MPC is recently qualified for Statoil,
Advantages:

- No need for dangerous chemicals or explosives
- The MPC can cut pipe at any angle, including horizontal.
- Clean cut
- Multiple cuts during single run, saving hours of time.

Dis-advantages:

- Problem to cut in compression. The cutter blade can get stuck and broke.

Figure 97 Picture and cut performed with MPC [49]

Well Cutter for pipe recovery from Welltec:

The well cutter is design to cut drill pipe, casing and liner. There are two sizes 31/8" Drill pipe cutter and 3 1/8" Casing cutter. The tool uses a rotating head to remove pipe incrementally, which prevents the creation of shavings. Due to the smooth, bevel surface it produces, a polishing trip with drill pipe may be eliminated.
Advantages:

- The well cutter are able to cut in both tension and compression
- No need for dangerous chemicals or explosives
- Able to cut pipe at any angle, including horizontal.
- Clean cut
- Multiple cuts during single run, saving hours of time
- The Well Cutter incorporates a 'fail-safe' mechanism that prevents the tool from getting stuck.

Figure 98 Picture and cut performed with Well Cutter [76]

7" Cutter from Welltec/Westerton

Cut pipe from 4,9" up to OD of 7". The tool has built in anchors and is self-centralizing.

Advantages:

- Design for multiple cuts in single run
- Able to cut through a buil up of scale
- No explosives or chemicals required
- Has performed successfully cut on 7" tubing

Dis-advantages:

- Problem to cut in compression. The cutter blade can get stuck and broke.

Figure 99 Picture and cut performed by 7" DECT [76]

Multicycle Pipe Cutter Tool

The MPCT cutter is pipe cutting system with multiple sets of cutters which can be selectively activated during the downhole operation. When one set of the cutter wears down, a replacement can be selected to continue operation.

Advantages:

– Less run and time to complete the operations

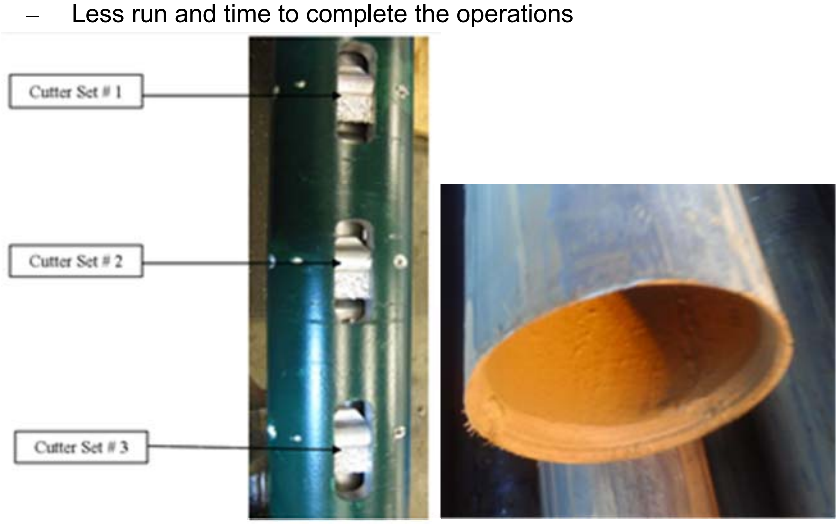


Figure 100 Picture and cut performed by Multicycle Pipe Cutter tool [44]

App H Cement Bond Logging Tools

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Cement Bond Logging Tools

APPLICATIONS

- Evaluation of cement quality
- Determination of zone isolation
- Location of cement top

Cement bond tools measure the bond between the casing and the cement placed in the annulus between the casing and the wellbore. The measurement is made by using acoustic sonic and ultrasonic tools. In the case of sonic tools, the measurement is usually displayed on a cement bond log (CBL) in millivolt units, decibel attenuation, or both. Reduction of the reading in millivolts or increase of the decibel attenuation is an indication of better-quality bonding of the cement behind the casing to the casing wall. Factors that affect the quality of the cement bonding are

- cement job design and execution as well as effective mud removal
- compressive strength of the cement in place
- temperature and pressure changes applied to the casing after cementing
- epoxy resin applied to the outer wall of the casing.

SLIM ARRAY SONIC TOOL

The Slim Array Sonic Tool (SSLT) is a digital sonic tool that provides conventional openhole sonic measurements, standard CBL amplitude and Variable Density* log (VDL), and attenuation measurements, which are less affected by borehole environmental conditions. The SSLT can also make a short-spacing (1-ft [0.30-m]) CBL measurements for cement evaluation in fast formations. The two transmitters and six receivers of the SSLT sonde have transmitter–receiver spacings of 1, 3, 3.5, 4, 4.5, and 5 ft [0.30, 0.91, 1.07, 1.22, 1.37, and 1.52 m] to compute the following:

- standard 3-ft CBL and 5-ft VDL measurements
- borehole-compensated (BHC) attenuation from the 3.5- and 4.5-ft spacing receivers
- near-pseudoattenuation from the 3-ft spacing receivers
- short-spacing attenuation from the 1-ft spacing receiver for cement bond measurement in fast formations that may affect the standard 3-ft spacing.

Cement Bond Logging Tools

SLIMXTREME SONIC LOGGING TOOL

The SlimXtreme* Sonic Logging Tool (QSLT) provides the same measurements as the SSLT of the cement bond amplitude, attenuation, and Variable Density display for evaluation of the cement bond quality of a cemented casing in high-pressure and high-temperature environments

CEMENT BOND LOG FROM DIGITAL SONIC LOGGING TOOL

The Digital Sonic Logging Tool (DSLT) uses the Sonic Logging Sonde (SLS) to measure the cement bond amplitude and provide a Variable Density display for evaluation of the cement bond quality of a cemented casing string. Variable Density or x-y waveform display of the sonic signal is presented in conjunction with the bond index and amplitude signal. The DSLT is also used in the open borehole environment for conventional sonic measurements of BHC (3- to 5-ft) transit time and long-spacing depth-derived BHC (DDBHC) (9- to 11-ft [2.74 to 3.35-m]) transit time.

CEMENT BOND LOG FROM HOSTILE ENVIRONMENT SONIC LOGGING TOOL

The Hostile Environment Sonic Logging Tool (HSLT) provides the same measurements of the cement bond amplitude and Variable Density display for evaluation of the cement bond quality of a cemented casing string as the SSLT in high-pressure and high-temperature environments.

SLIM CEMENT MAPPING TOOL

The Slim Cement Mapping Tool (SCMT) is a through-tubing cement evaluation tool combinable with the PS Platform* production logging service for a variety of well diagnostics. The two sizes are 11⁄16 in [4.29 cm] for the standard (302 degF [150 degC]) temperature rating and 2⅛ in [5.24 cm] with a 392 degF [200 degC] temperature rating. The SCMT is suitable for running workover operations and in new wells. SCMT operations provide a clear advantage in workover wells because there is no need to pull tubing above the zone of interest for cement evaluation. The SCMT is capable of running through most tubings to evaluate the casing below. In new wells the SCMT is an excellent tool for evaluating casing that is 7⅝ in [19.36 cm] or less.

The SCMT features a single transmitter, two receivers spaced at 3 and 5 ft from the transmitter, and eight segmented receivers 2 ft [0.61 m] from the transmitter. The output of the near (3-ft) receiver is used for CBL and transit-time measurement. The output of the far (5-ft) receiver is used for the VDL measurement. The eight segmented receivers generate a radial image of the cement bond variation.

MEMORY SLIM CEMENT BOND LOGGING TOOL

The Memory Slim Cement Bond Logging Tool provides through-tubing 3-ft CBL and 5-ft VDL measurements with the same accuracy and quality as surface-readout logs. Because of its slim size, the 11⁄16-in tool can be run into the zone of interest without having to remove the tubing from the well. The tool simultaneously records gamma ray, casing collar location, pressure, temperature, and waveforms in a single pass, with the waveforms fully digitized downhole. More than 40 h of combined tool running time is possible, including 16 h of continuous waveform recording time. Depth-recording systems are available for both hazardous and nonhazardous environments.

The Memory Slim CBL Tool can be run with other Memory PS Platform* production logging tools for complete well and reservoir evaluation in one descent. The tools and sensors can be conveyed in the borehole by drillpipe, coiled tubing, slickline, or unintelligent tractor. PS Platform software is used to perform onsite data processing or any necessary postprocessing and prepare the log presentation.

Measurement Specifications

	SSLT	QSLT	DSLT	HSLT	SCMT-C and SCMT-H	Memory Slim CBL Tool
Output	3-ft [0.91-m] CBL and attenuation, 1-ft [0.30-m] attenuation, 5-ft [1.52-m] Variable Density log	3-ft [0.91-m] CBL and attenuation, 1-ft [0.30-m] attenuation, 5-ft [1.52-m] Variable Density log	3-ft [0.91-m] amplitude CBL, With SLS-C and SLS-D: 5-ft [1.52-m] Variable Density log	3-ft [0.91-m] amplitude CBL, 5-ft [1.52-m] Variable Density log	3-ft [0.91-m] amplitude CBL, 5-ft [1.52-m] Variable Density log, cement bond variation map	3-ft [0.91-m] CBL, 5-ft [1.52-m] Variable Density log, gamma ray, CCL, baseline, cement compressive strength
Logging speed	3,600 ft/h [1,097 m/h]	3,600 ft/h [1,097 m/h]	3,600 ft/h [1,097 m/h]	3,600 ft/h [1,097 m/h]	1,800 ft/h [549 m/h]	1,800 ft/h [549 m/h]
Vertical resolution	Near attenuation: 1 ft [0.30 m] CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m]	Near attenuation: 1 ft [0.30 m] CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m]	CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m]	CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m]	CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m] Cement bond variation map: 2 ft [0.61 m]	CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m]
Depth of investigation	CBL: Casing and cement interface VDL: Depends on bonding and formation	CBL: Casing and cement interface VDL: Depends on bonding and formation	CBL: Casing and cement interface VDL: Depends on bonding and formation	CBL: Casing and cement interface VDL: Depends on bonding and formation	CBL: Casing and cement interface VDL: Depends on bonding and formation	CBL: Casing and cement interface VDL: Depends on bonding and formation
Mud type or weight limitations	None	None	None	None	None	None
Combinability	Part of SlimAccess* system	Part of SlimXtreme system	Combinable with most tools	Part of Xtreme* system, combinable with most tools	Combinable with PS Platform system	Combinable with Memory PS Platform system
Special applications	Logging through drillpipe, tubing, and in small casing Fast formations	Logging through drillpipe, tubing, and in small casing Fast formations			Logging through drillpipe, tubing, and in small casing Fast formations	Logging through drillpipe, tubing, and in small casing

Mechanical Specifications

	SSLT	QSLT	DSLT	HSLT	SCMT-C and SCMT-H	Memory Slim CBL Tool
Temperature rating	302 degF [150 degC]	500 degF [260 degC]	350 degF [175 degC]	500 degF [260 degC]	SCMT-C: 302 degF [150 degC] SCMT-H: 392 degF [200 degC]	302 degF [150 degC]
Pressure rating	14,000 psi [97 MPa]	30,000 psi [207 MPa]	20,000 psi [138 MPa]	25,000 psi [172 MPa]	15,000 psi [103 MPa]	15,000 psi [103 MPa]
Casing size—min.	2⅞ in [7.30 cm]	4½ in [11.43 cm]	5½ in [13.97 cm]	5½ in [13.97 cm]	SCMT-C: 2⅜ in [6.03 cm] SCMT-H: 2⅞ in [7.30 cm]	2⅞ in [7.30 cm]
Casing size—max.	8⅝ in [21.91 cm]	8⅝ in [21.91 cm]	13⅜ in [33.97 cm]	13⅜ in [33.97 cm]	7⅝ in [19.37 cm]	7⅝ in [19.37 cm]
Outside diameter	2.5 in [6.35 cm]	3 in [7.62 cm]	3.625 in [9.21 cm]	3.875 in [9.84 cm]	SCMT-C: 1.6875 in [4.29 cm] SCMT-H: 2.06 in [5.23 cm]	1.6875 in [4.29 cm]
Length	23.1 ft [7.04 m]	Without inline centralizer: 23 ft [7 m] With inline centralizer: 29 ft [8.8 m]	With SLS-E: 16.62 ft [5.07 m] With SLS-F: 13.41 ft [4.09 m]	25.5 ft [7.77 m]	SCMT-C: 23.45 ft [7.14 m] SCMT-H: 20.05 ft [6.11 m]	23.45 ft [7.15 m]
Weight	222 lbm [100 kg]	270 lbm [122 kg]	With SLS-E: 313 lbm [142 kg] With SLS-F: 260 lbm [118 kg]	440 lbm [199 kg]	SCMT-C: 100 lbm [45 kg] SCMT-H: 112 lbm [51 kg]	100.3 lbm [45.4 kg]
Tension	10,000 lbf [44,480 N]	15,000 lbf [66,720 N]	25,700 lbf [114,320 N]	20,000 lbf [88,960 N]	5,000 lbf [22,240 N]	5,000 lbf [22,240 N]
Compression	4,000 lbf [17,790 N]	3,000 lbf [13,340 N]	2,970 lbf [13,210 N]	6,000 lbf [26,690 N]	150 lbf [670 N]	150 lbf [670 N]

Cement Bond Logging Tools

APPLICATIONS

- Cement evaluation
- Casing inspection
  - Corrosion detection and monitoring
  - Detection of internal and external damage or deformation
  - Casing thickness analysis for collapse and burst pressure calculations

USI ULTRASONIC IMAGER TOOL

The USI* UltraSonic Imager tool (USIT) uses a single transducer mounted on an Ultrasonic Rotating Sub (USRS) on the bottom of the tool. The transmitter emits ultrasonic pulses between 200 and 700 kHz and measures the received ultrasonic waveforms reflected from the internal and external casing interfaces. The rate of decay of the waveforms received indicates the quality of the cement bond at the cement/casing interface, and the resonant frequency of the casing provides the casing wall thickness required for pipe inspection. Because the transducer is mounted on the rotating sub, the entire circumference of the casing is scanned. This 360° data coverage enables the evaluation of the quality of the cement bond as well as the determination of the internal and external casing condition. The very high angular and vertical resolutions can detect channels as narrow as 1.2 in [3.05 cm]. Cement bond, thickness, internal and external radii, and self-explanatory maps are generated in real time at the wellsite.

Cement Bond Logging Tools

Measurement Specifications

	USIT
Output	Acoustic impedance, cement bonding to casing, internal radius, casing thickness
Logging speed	1,800 ft/h [549 m/h]
Range of measurement	Acoustic impedance: 0 to 10 MRayl [0 to 10 MPa.s/m]
Vertical resolution	Standard: 6 in [15.24 cm]
Accuracy	Less than 3.3 MRayl: ±0.5 MRayl
Depth of investigation	Casing-to-cement interface
Mud type or weight limitations†	Water-base mud: Up to 15.9 lbm/gal Oil-base mud: Up to 11.2 lbm/gal
Combinability	Bottom only tool, combinable with most tools
Special applications	Identification and orientation of narrow channels

† Exact value depends on the type of mud system and casing size.

Mechanical Specifications

	USIT
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Casing size—min.	4½ in [11.43 cm]
Casing size—max.	13⅜ in [33.97 cm]
Outside diameter†	3⅜ in [8.57 cm]
Length†	19.75 ft [6.02 m]
Weight†	333 lbm [151 kg]
Tension	40,000 lbf [177,930 N]
Compression	4,000 lbf [17,790 N]

† Excluding the rotating sub

USIT Rotating Sub Mechanical Specifications

	USRS-AB	USRS-A	USRS-B	USRS-C	USRS-D
Outside diameter	3.41 in [8.66 cm]	3.58 in [9.09 cm]	4.625 in [11.75 cm]	6.625 in [16.83 cm]	8.625 in [21.91 cm]
Length	9.8 in [24.89 cm]	9.92 in [25.20 cm]	9.8 in [24.89 cm]	8.3 in [21.08 cm]	8.3 in [21.08 cm]
Weight	7.7 lbm [3.5 kg]	7.7 lbm [3.5 kg]	10.6 lbm [4.8 Kg]	15.0 lbm [6.8 kg]	18.3 lbm [8.3 kg]

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07-CE-005 March 2007

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