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ABBREVIATIONS

AA	Anti Agglomerants
BHA	Bottom Hole Assembly
BOP	Blow Out Preventer
BOPD	Barrels Oil Per Day
CT	Coiled Tubing
DHSV	Downhole Safety Valve
DIACS	Downhole Instrumentation and Control Systems
DP	Dynamic Position
DST	Drill Stem Test
EDP	Emergency Disconnect Package
ESD	Emergency Shut Down
FSC	Fail-safe Close
GoM	Gulf of Mexico
GOR	Gas Oil Ratio
HPHT	High Pressure High Temperature
HWO	Hydraulic Workover
HSE	Health, Safety and Environment
IMR	Inspection Maintenance and Repair
IWOCS	Installation Work Over Control System
KHI	Kinetic Hydrate Inhibitor
LDHI	Low Dosage Hydrate Inhibitor
LIP	Lower Intervention Package
LLP	Lower Lubricator Package
LRP	Lower Riser Package
LUB	Lubricator Tubular
LV	Lubricator Valve
LWI	Light Well Intervention
MEG	Mono Ethylene Glycol
MSDS	Material Safety Data Sheet
P&A	Plug and abandon
PCH	Pressure Control Head
PLT	Production Logging Tool
RLWI	Riserless Light Well Intervention
ROV	Remotely Operated Vehicle
SFT	Surface Flow Tree
TRSCVSS	Tubing Retrievable Surface Controlled Subsurface Safety Valve
TRT	Tree Running Tool
TTD	Through Tubing Drilling
ULP	Upper Lubricator Package
WBE	Well Barrier Element
WCP	Well Control Package

ABSTRACT

Worldwide, the number of subsea wells showed a substantial increase over the last decade. This trend is particularly relevant for deep- and ultra deep-water field developments, indicating that the offshore oil and gas production continues to move into deeper regions. West Africa, South America and the Gulf of Mexico (GoM) lead the deep-water operations and related subsea well intervention activities.

The scope of this study is to explain why deep-water well intervention has become such a requirement and discuss the factors that are propagating this need. This thesis principally focuses on light well intervention operations performed on subsea wells. The challenges that follow by moving to increasing depths are presented and solutions are discussed. In particular, an assessment of selecting hydrate prevention inhibitors is presented, as the formation of hydrates is one of the major limiting factors regarding operations at large depths.

Well integrity during well intervention is another aspect that is covered in this study, based on the standard NORSOK D-010 *"Well integrity in drilling and well operations"* for evaluations. This section contains technical and operational solutions to reduce the risk of uncontrolled release of formation fluids throughout the well intervention operation.

Finally, this thesis outlines that well intervention operations can be economical and feasible in deep- and ultra-deep subsea wells by employing recently developed vessels, provided with dynamic positioning systems and designed specifically for subsea well intervention purposes.

INTRODUCTION

Well intervention is any operation that is executed in order to increase the performance or extend the productive life of oil or gas wells. Subsea well intervention has been performed extensively over at least two decades to service wells and to increase recovery from these wells in shallow waters. As the subsea developments move deeper, deep water well intervention becomes a vital subject for both operator and service companies.

As field developments move deeper and deeper, technology for deep-water operations has to advance. Operators are in need for continuous search of more economical solutions since the new technology enables to perform old routines in new ways [1]. Besides maturing deep-water fields in GoM, West Africa and other regions, production of two new deep-water discoveries, one in Brazil and second in Nigeria, has recently started. As deep-water well intervention is an important necessity today, it is becoming a greater requirement for the future.

Deep water and ultra deep-water intervention of subsea wells has been a huge challenge for oil and gas producers so far. Oil recovery from subsea wells are considerably low compared to recovery from platform wells. Typical recovery from surface wells is 50% whereas recovery from subsea wells can be as low as 20% (typically 25%). Moreover, well interventions presented on subsea wells are limited. Ideally, the recovery from subsea wells should be 15%-30% in addition to current recovery. Despite the challenges, subsea wells are gradually becoming critical for operator companies in terms of production and deep-water development. The potential of subsea wells is driving the industry to deep-water well intervention.

Currently, most deep-water operations and subsea well intervention activities worldwide are concentrated in Africa, Latin America and the U.S. GoM.

Brazil has a long history with deep-water operations [2]. It is commended that Brazil's deep-water operations remain quite robust because of its experience and willingness to apply local knowledge and experience. More than 95 percent of deep-water fields discovered and on-stream from 1983-2007 belong to Brazil. A major part of the operational wells in South America were subsea wells in Brazil. The other two countries with reported deep-water results are Mexico and Trinidad.

GoM has been one of the most productive oil producing fields in the world in recent years. It has been established as a major hydrocarbon- producing region due to the discoveries over the past 20 years. In [2], the U.S. GoM is described as one plane of the deep-water golden triangle. The region accounted for 55 percent of discovered deep-water fields and 62 percent of discovered fields on-stream worldwide between 1983 and 2007. The market is becoming very appealing for well service companies, there are approximately 760 subsea wells in production or planned to be in production and reaching the same level of maturity as in Brazil.

Deep-water operations in Africa are rather immature when compared to other regions as exploration and production activities in the region have started in the early 1990s. The first discovery was reported in 1995 and the field came on-stream in 1997. Nigeria and Angola are the focus regions of most deep-water operations and activities in Africa [2].

Although the North Sea is considered to be shallow to medium water region, it is a significant point of interest with regards to both light and heavy intervention operations, especially riserless light well intervention (RLWI) operations. An extensive number of wells already have reached a mature status. Statoil governs the Norwegian sector, where as BP dominates in UK sector. Statoil has been the leading developer of RLWI technology in cooperation with Island Offshore and FMC Technology; and now, it is the initiator of developing a vessel type rig, which can perform heavy intervention.

Traditionally, subsea wells are intervened by semi submersible rigs with marine risers. However, this seems to be one of the biggest challenges in deep-water subsea wells because of the extreme costs and unavailability of these rigs. The solution of this challenge has been found in monohull vessels, specifically equipped for well intervention with riser or without riser.

Following some given basic knowledge about well intervention, this thesis focuses on subsea wells and recently developed technologies for accessing subsea wells. Then, it highlights the challenges encountered in deep-water interventions. After that, the major concern of deep-water operations, hydrate formation and prevention is presented. The thesis ends with some examples of well intervention applications, aiming to emphasize the challenges that are described in the scope of this work.

1. WELL INTERVENTION

1.1 Definition

Well intervention is defined as any operation performed on an oil or gas well, throughout the well's productive life or at the end of the productive life, in order to improve production performance, to extend production life, and to change condition of the well and well geometry [3]. Well intervention is commonly categorized into two groups:

- Heavy intervention
- Light intervention

Heavy interventions are the operations which uses a heavy (e.g. 18 3/4") drilling blow out preventer (BOP) for pressure control such as removing christmas trees (Xmas tree), replacing tubing, and performing side- tracking. On the other hand, light interventions are the operations, which can be performed inside or through the Xmas tree and completion tubing. The most common examples are wireline and coiled tubing operations [4], which are explained in the following section.

In order to obtain optimal production from a reservoir or to maintain a subsea well, wells are diagnosed according to collected well and reservoir data. Then, the approach to intervene is determined depending on reservoir conditions, the nature of the produced or injected fluid(s), the configuration and status on the equipment installed in the well [4], and cost of the overall operation.

The frequency of well intervention that will be performed during the life of a field is difficult to predict, since the decision to intervene a well is dependent on numerous variables, including reservoir characteristics, infrastructure and economic considerations [5].

Depending on the type of intervention methods, the well can be either "live" , i.e. the bottom-hole pressure in the well bore is lower than the pore pressure, or it can be "killed" before entering. The latter means that a heavy fluid had been pumped causing the bottomhole pressure to exceed the pore pressure. . The difference in both methods is briefly explained in the next section.

1.2 Types of Well Intervention Methods

There are different types of methods for intervention operations based on the tools and the equipment to be used.

1.2.1 Pumping

Pumping is the most basic intervention method since it does not require any equipment placement into the well itself [3]. The main purpose of pumping is protecting the well against scale or hydrates by pumping scale or hydrate inhibitors, respectively. A second use is pumping kill fluid into the well for killing. Another application is pumping of chemicals such as acids for cleaning the lower completion or stimulating the reservoir [6].

1.2.2 Wireline

Wireline is the general term that covers the cabling technology used for lowering and raising equipment into the well by an electro-hydraulic or diesel powered winch. Wireline operations can be performed both from fixed platforms and floating units [7]. Most wireline surface equipment is placed on an independent skid, which is composed of wireline reel, power supply and related control and connection equipment (Figure 1).

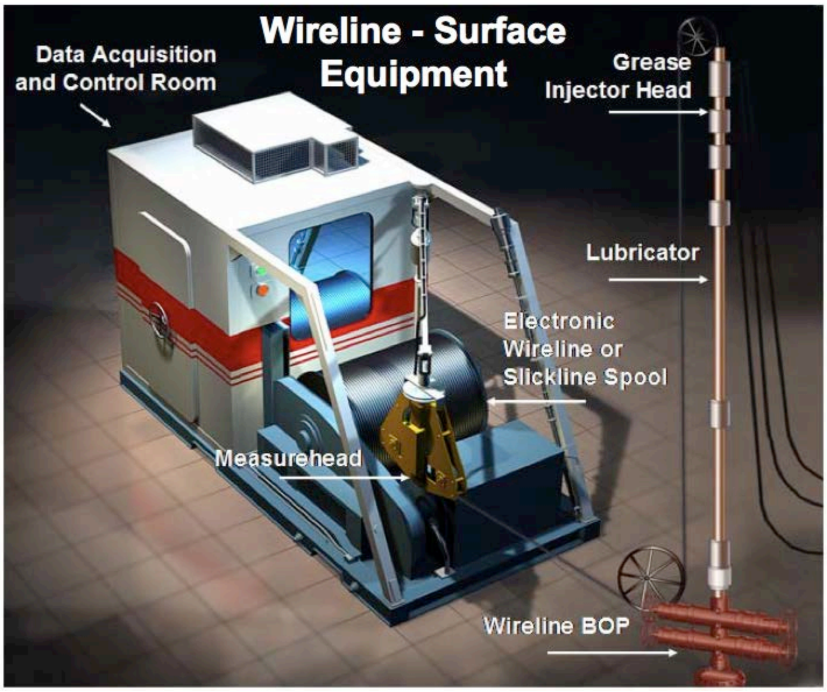


Figure 1 – Wireline Surface equipment [5]

There are two different types of cable systems, slickline and braided line (Figure 2). Braided line can be either with an electric line or without it.

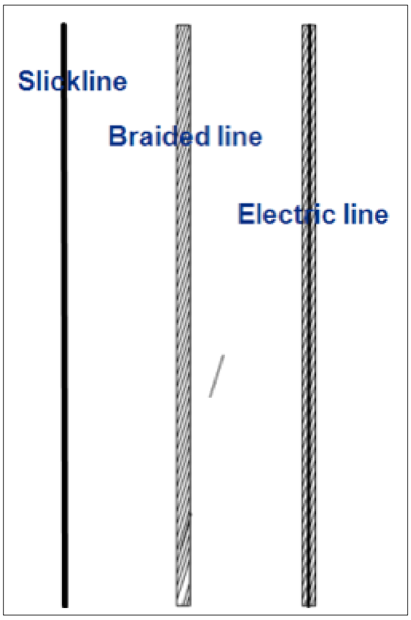


Figure 2 - Types of wireline cables [35]

Slickline and braided line mainly differs in terms of operations that can be performed and sealing mechanisms. Stuffing box is the main sealing mechanism in slickline whereas grease injection head in braided line replaces stuffing box. Since grease needs to be injected around the braided line for sealing, BOP for braided line has one additional ram.

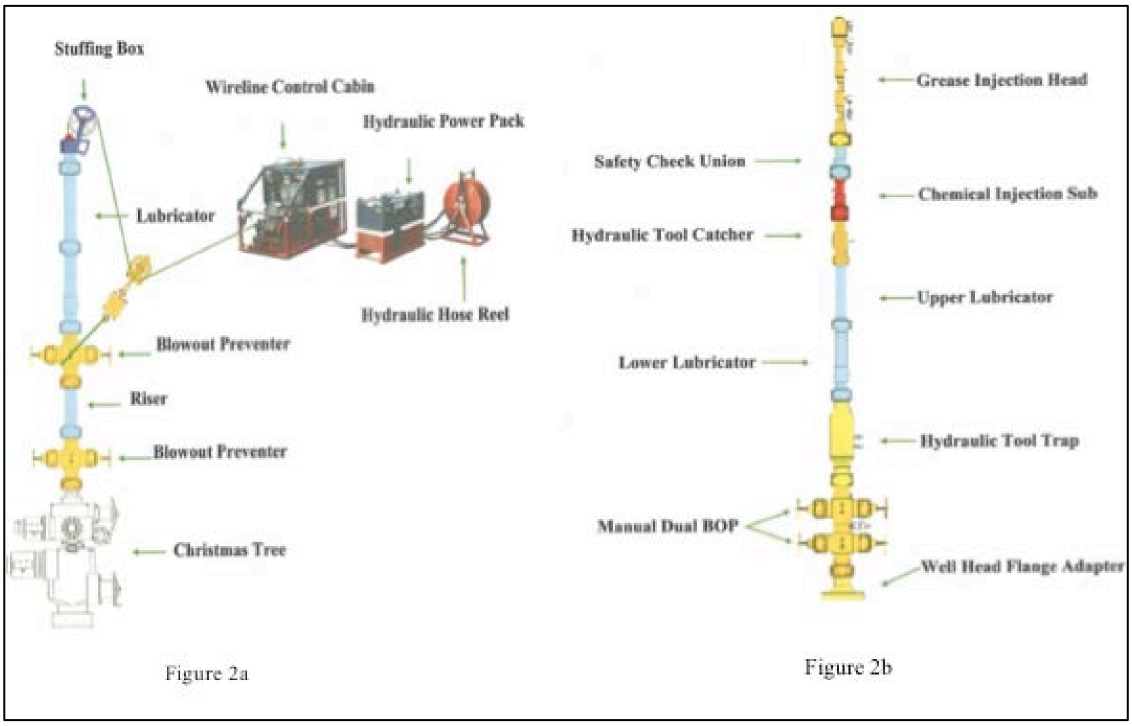


Figure 3 – The system overview for slickline (3a) and braided line (3b) [35].

Slickline

A slickline is a solid wire without a conductor, thus it is used for mechanical operations only. The most common sizes are 3/32, 7/64 and 1/8 inches [5].

Slickline is mainly used for operations such as fishing, gauge cutting, setting or removing plugs, deploying or removing wireline retrievable valves, and cleaning well (organic deposits & scale) [3]. Tools used in slickline operations are mechanical activated by operation of jars [7].

Braided line

Braided line is heavier and more complex than slickline. It requires a grease injection system in the rig up and also an additional shear-seal BOP. Braided line without electric cable is used for heavy fishing operations in which slickline is not strong enough to retrieve tools. On the other hand, operations, which acquire electrical signals such as logging and perforating, are performed with braided line including an electric cable [7].

The arrangement of the equipment and tools used in both slickline and braided lines are detailed in APPENDIX A.

1.2.3 Coiled Tubing (CT)

The name of the operation comes from the flexible steel tubing, which is made of strips of high strength steel that are rolled and seam welded. The tubing is coiled onto a reel, becoming coiled tubing. Hence coiled tubing operation is composed of deploying this flexible tubing into a wellbore to perform various well servicing and to circulate fluids [5].

Below, Figure 4 demonstrates the surface equipment arrangement for coiled tubing operations. The coil is pushed and pulled by a mechanical tool called injector head. The curved guide beam on top of the injector head is called gooseneck, which threads the coil into the injector body. Underneath the injector is the stripper, which holds rubber pack off elements running a seal around the tubing to isolate the well's pressure. Below the stripper is the BOP, which delivers the ability to cut the coiled tubing pipe and seal the well bore and hold and seal around the pipe. The BOP rests on top of the riser, which keeps the pressurized tunnel down to the top of the Xmas tree. Between the Xmas tree and the riser is the final pressure barrier, the shear-seal BOP, which can cut and seal the pipe [8].

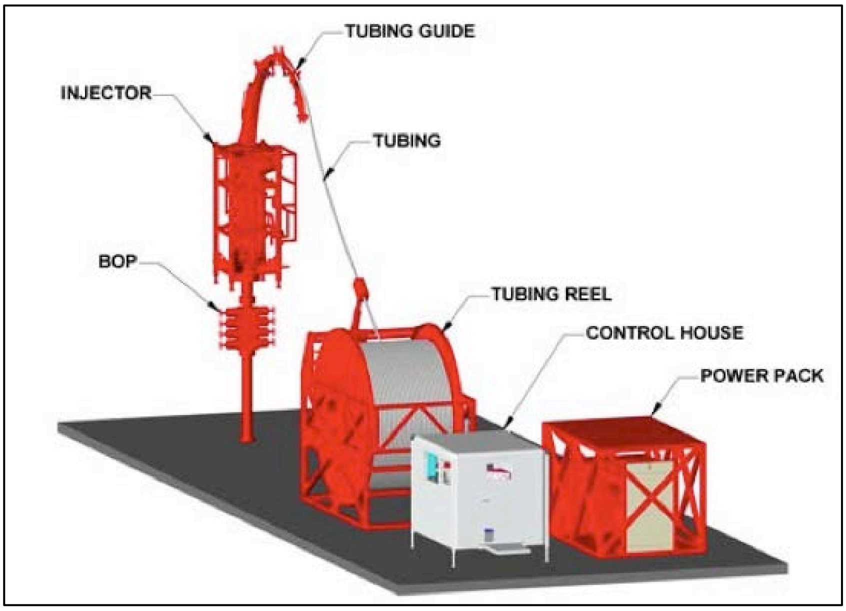


Figure 4 – General surface equipment arrangement of coiled tubing [5]

The main coiled tubing applications are acidizing/stimulation, sand removal, proppant fill and nitrogen injection into a dead well to kick of the reservoir. It can also be an alternative to wireline when it is not possible to use wireline tractor or lower the tool string due to high deviation in the well.

A drilling can be used to perform coiled tubing operations since the drilling derrick is used to support the surface equipment. Alternatively, platforms with no drilling facilities or a self-supporting tower can be used instead. For onshore applications, smaller service rigs, or mobile self-contained coiled tubing rig can be utilized [8].

CT has many advantages over both wireline and snubbing. The major advantage is cost-effectiveness. Surface equipment units are self-contained hydraulically powered workover units that provide substantial time and cost savings when compared to using a conventional workover rig. Since there is no joint connection, rig up and trip time is highly reduced. Fluid can be continuously circulated through pipe while lowering the tubing into the wellbore. The production tubing life is increased and acid contamination due to tubing scale is prevented since down hole fluids are delivered locally. The operation is possible to perform on live wells; and many wireline operations can be conveyed in highly deviated and horizontal well bores by installing an e-line inside coiled tubing [5].

APPENDIX A gives details about the coiled tubing equipment.

1.2.4 Hydraulic Workover (HWO)

As described in [5], pushing pipes with jointed sections into the well by using hydraulic cylinders is hydraulic workover and operation can be performed either under pressure or after killing the well.

HWO is divided into the following categories depending on the application area:

High Pressure Snubbing

Thrusting pipe into well under pressure is referred as snubbing. High pressure snubbing is an application in which HWO is performed in a live well because coiled tubing is not strong enough.

Hydraulic Rig Assist

By description, a rig assist unit is not a stand-alone type unit and operates only in combination with the workover rig. A hydraulic rig assist unit contributes conventional workover rigs and supplements the work performed by rigs to make the intervention job more efficient.

Major Workover

Major workover jobs are typically the pulling of the production tubing for repairs. HWO units have the ability to perform a major workover on the well, and compete directly with the work that is traditionally performed by conventional workover rigs.

Jack and slip assemblies, pipe rack, pipe handling mast and winches, work basket, BOP, power units, operator control console, BOP control console and auxiliary equipment such as accumulator package are the most common parts of the surface equipment (Figure 5).

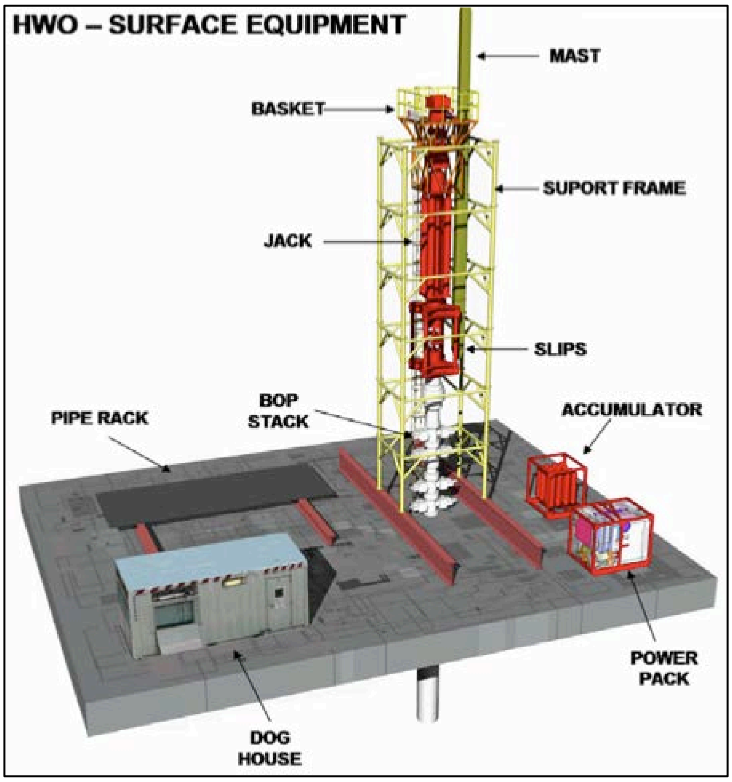


Figure 5 – Hydraulic workover unit surface equipment arrangement [5]

The most important applications are installing/retrieving plugs or downhole safety valve (DHSV) where force is necessary, fishing, milling, gravel packing, squeeze cementing/cement plugging, installing/retrieving new production tubing. Snubbing can also be applied during underbalanced drilling and underbalanced completion in order to avoid formation damage. Other application areas are perforating, killing wells, acidizing and well cleaning. Although this type of operation beneficial because of circulation and rotation, it is unfavorable due to longer rig-up and tripping time [7]. It also may become more risky compared to wireline and coiled tubing due to complexity of pressure control but problems are always avoidable [9].

1.3 Units Used In Intervention Operations

Intervention operations can be performed from different types of units depending on the method and the equipment to be used. As described in [10], Statoil divides the rig selection in three categories:

- Category A – Rislerless Light Well Intervention (RLWI)
- Category B – Heavy Intervention and Through Tubing Drilling

- Category C – Drilling and Completion Rig

In addition to the categories listed above, it is essential to mention about dynamically positioned vessels performing light well intervention with high-pressure riser system. These vessels can be considered as a transition between Category A and Category B.

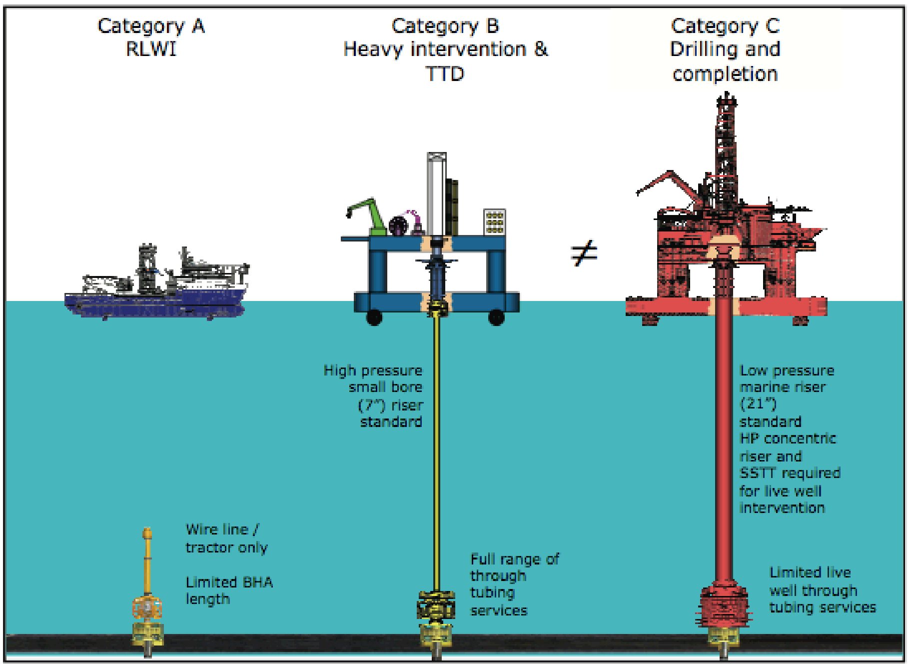


Figure 6 - Illustration showing the differences between Categories A, B and C [10]

1.3.1 Category A

RLWI vessels, which have no riser, attached to the well are in this category (Figure 7). In terms of intervention operations, mainly wireline operations are possible with these vessels. There are also limitation for operation depth (see chapter 5).

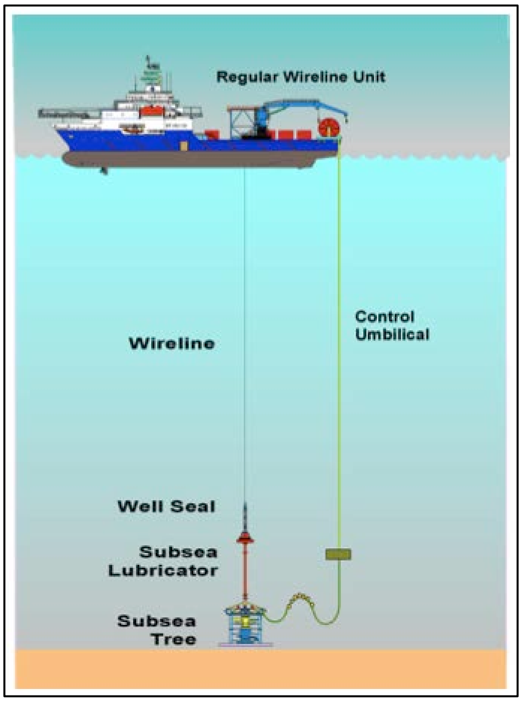


Figure 7 - Monohull vessel performing RLWI [36]

Island Offshore may be referred as the leading service company with its RLWI vessels. The company owns three RLWI vessels: Island Frontier and Island Wellserver are awarded contracts by Statoil in Norway; and BP in UK awards Island Constructor a contract. In addition to wireline operations, these vessels are able to provide services such as subsea installation and construction, P&A work, trenching, crane work, survey work together with ROV (Remotely Operated Vehicle) operations [11]. The specifications and more details about Island Offshore's RLWI vessels are presented in APPENDIX B.

Island Frontier	**Island Wellserver**	**Island Constructor**
		
• Sub sea installation and module handling operations • Riserless well intervention services • Trenching • ROV operations	• Riser less light well intervention services • Installation and module handling operations • Trenching • ROV operations • P&A Work • Construction work • Diving	• P&A work • Construction work • Tower and module handling • Installation work • IMR work • Survey work • Crane work • Diving work

Figure 8 - Island Offshore RLWI vessels and their services [11]

1.3.2 Semi-submersible and Monohull Vessels with Rigid Riser

These vessels are designed with an open and large deck, enabling multiple activities. They are equipped with heavy lift capacity cranes and derrick with wide work area, allowing for rapid positioning of all essential tools and equipment. The intervention operations are applied with deployment of cost effective risers, eliminating the use of conventional BOPs hence having the advantage over conventional rigs. Moreover, flexible response times and short mobilization periods are the most appealing properties of these vessels.

In relation to intervention operations, these vessels are able to provide coiled tubing operations on top of wireline operations. The tower designed in a way to handle both coiled tubing and wireline equipment together with tools. Other possible operations mainly depend on the service provider and the vessel itself.

Aker Solutions owns Skandi Aker, specially designed and equipped for riser-based deep-water subsea well intervention operations. The vessel is capable of performing intervention operations up to 3000-meter water depth. It is classified according to DNV's WELL-notation, meaning the vessel is able to take hydrocarbons on board. As a result, the vessel can perform well testing and clean-up, flaring off hydrocarbons through a flare at the stern [13]. The additional operations that she can perform are listed in Figure 9.

- Subsea well clean-up and testing
- Pumping services
- Installation and retrieval of XMT systems
- Subsea construction and installation
- Subsea maintenance
- ROV operations/surveying
- Set up for shallow water riserless subsea intervention
- Wireline and coiled tubing subsea well intervention packages

Figure 9 - Deep water well intervention Skandi Aker [13]

The specific details about Skandi Aker are included in APPENDIX B.

Another service company, providing multi service vessels, is Helix Well Ops. The Modu Q4000 is a DP3 semi-submersible specifically designed for well intervention and construction in water depths to 3000 meters. Seawell has been operating throughout the North Sea and Atlantic margin as a Light Well Intervention (LWI) vessel since 1987, initiating monohull-based subsea wireline and coiled tubing services. Well Enhancer is designed to minimize production downtime and provide a cost-effective method of maintaining subsea production systems [14]. Figure 10 presents the capabilities of these three vessels. APPENDIX B gives the itemized specifications of these vessels.

Modu Q4000	Seawell	Well Enhancer
		
• Slimbore drilling • Slimbore completion • Decommisioning well intervention • Subsea completion • Well intervention operations	• Wireline and coiled tubing operations • Well clean-up • Well stimulation • Full IMR and construction services	• Well stimulation • Subsea Xmas tree recovery / replacement • Live and suspended well abandonment • Full IMR and construction services • Well intervention operations

Figure 10 - Helix Well Ops's LWI vessels and the extra operations that they can perform [14]

1.3.3 Category B

This category is currently new in the industry. Statoil is developing this rig in cooperation with Aker Solutions. The category B rig will bring new sort of service with its design and equipment for the industrialization of drilling and intervention services [10, 12].

The aim is to perform heavy intervention such as coiled tubing, with high pressure small bore risers. Through tubing drilling will also be feasible with this type of rig.

A number of different types of well interventions using wireline and coiled tubing operations will be possible with the planned design of Category B. In addition to wireline and coiled tubing operations, the rig is also designed to perform sidetrack drilling from production tubing (through tubing drilling – TTD) in a manner that allows simultaneous production from both the new sidetrack and existing production tubing. The well services are conducted through existing subsea Christmas trees.

The rig will be a smaller semi-submersible rig hull type with full dynamic positioning (DP) or mooring assisted station keeping options. It will be capable to handle live well returns. The unit will be simpler to operate with less power requirement when compared to conventional rigs.

Figure 11 - Illustration of future coming Cat B [12]

The topside system will be designed for through tubing operation with 2 7/8 and 3 ½ inch drill pipes. By integrating the coiled tubing in the rig, hence avoiding use of riding belts and minimizing heavy lifts, health, safety and environment (HSE) conditions will be improved.

1.3.4 Category C

This category covers the conventional rigs with low-pressure risers. These rigs are also equipped with workover equipment to perform interventions on the wells with high-pressure risers [10]. Conventional rigs can carry out all heavy well interventions, yet the high cost and unavailability of these rigs is the greatest obstacle for use as well intervention facilities.

2. SUBSEA WELLS

Subsea wells hold a very significant place in deep and ultra deep waters. Installing subsea wells and trees is the most applicable method when traditional surface facilities, such as steel-piled jacket, might be either technically unfeasible or uneconomical due to water depth [15]. Hence, it is essential to describe the subsea well, its components and how to access it for intervention purposes. This chapter gives a comparison of subsea and surface wells, and then presents brief figures about subsea wellhead and subsea tree, which are key points in accessing subsea wells.

2.1 Subsea Well vs. Surface Well

A *subsea well*, also called a *wet tree* is a well with wellhead installed on the seabed and attached to a host facility at the surface; on the other hand, a *surface well* or *dry tree*, is accessible at the surface facility.

Figure 12a

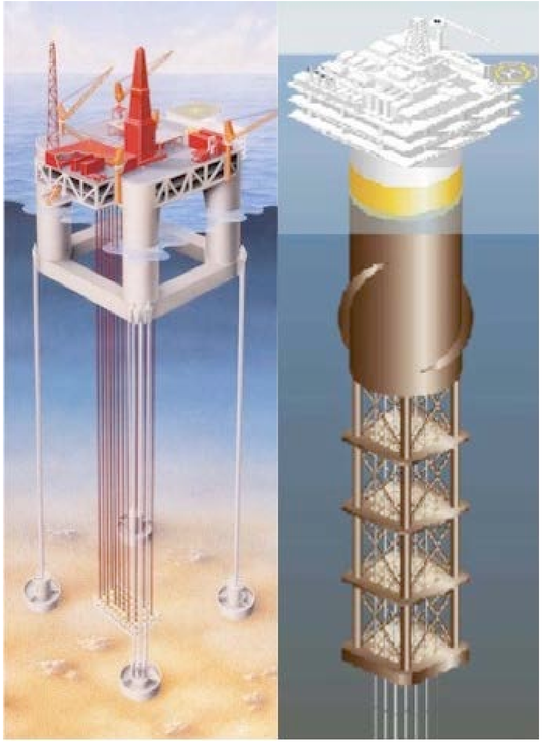


Figure 12b

Figure 12 - Demonstration of surface wells (12a) vs subsea wells (12b) [16]

Surface wells are located on or close to a platform, whereas subsea wells can be anywhere depending on the field development method [17].

Surface wells are advantageous in regards with proximity of people for well control at surface and direct vertical access to wells for future intervention activities. Yet, these advantages become disadvantages, since well control at the surface is a safety concern and requirement of complex riser design and heavy lifting for riser installations. On the other hand, subsea wells are accessible at the seabed, isolated from the people and safer in terms of well control, but exposed to the ambient seabed conditions [16, 17].

For subsea wells, marine risers and subsea trees are run through a central moon pool, which may also be preferred for installing other equipment such as manifolds and BOPs. Subsea wells are also suitable for extensive reservoir structures. Moreover, different types of vessels can be utilized for intervention purposes with simplified riser-vessel interfaces, providing a cost effective solutions compared to surface wells.

For surface wells, the size of the central well bay on the platforms is decided according to well count and spacing, since topside equipment has to be organized around the well bay. A large production manifold is required on deck, and a skiddable rig is required for individual well interventions [17].

As a summary, the surface well installations are still not considered as feasible for deep water and ultra deep-water fields although they are commonly used in shallow and medium water depths. Worldwide, more than 70% of the wells in deep-water fields are subsea wells [17].

2.2 Subsea Wellhead and Xmas Trees

This section explains briefly subsea wellhead and Xmas tree. They are one of the fundamental equipment in a subsea production system and represents the access point to the well for intervention operations.

2.2.1 Subsea Wellhead

The subsea wellhead supports and seals casing strings and also supports the BOP stack during drilling and the subsea tree after completion. The major function of the subsea wellhead system is to act as a mechanical and pressure-containing fastening point on the seabed for the drilling and completion systems and for the casing strings in the well. The wellhead system is composed of wellhead housing, conductor housing, casing hangers, annulus seals, and guide base. It integrates internal profiles for support of the casing strings and isolation of the annulus. Additionally, the system combines facilities for guidance, mechanical support, with the connection of the systems used to drill and complete the well. As design of a wellhead is considered, it should be designed and installed with minimum sensitivity to water depth and sea conditions [17]. Figure 13 shows a wellhead system by Cameron specifically designed for 3000 m water depth.

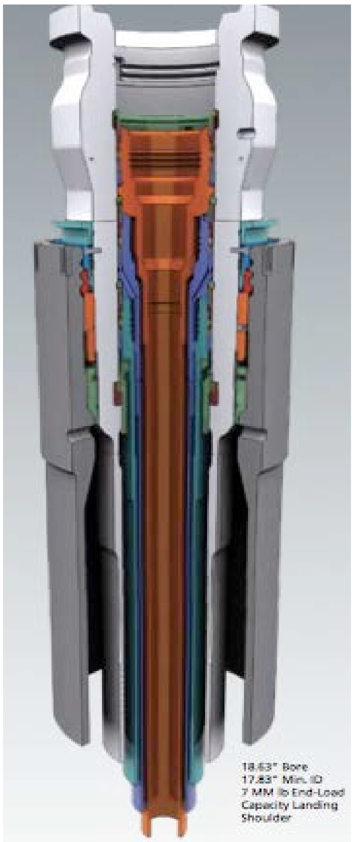


Figure 13 - Cross section of a subsea wellhead designed by Cameron for deep waters [18].

2.2.2 Subsea Xmas Tree

Quote from [17]: A subsea Xmas tree is basically a stack of valves installed on a subsea wellhead to provide a controllable interface between the well and production facilities. It is composed of a variety of valves, which are used for testing, servicing, regulating, or choking the stream of produced oil, gas, and liquids coming up from the well below. Different types of subsea Xmas trees may be used for either production or water/gas injection. Configurations of subsea Xmas trees may differ based on the requirements of the projects and field developments. Functions of a subsea Xmas tree can be listed as the following:

- Enable flow of the produced fluid from the well or the injection of water or gas from surface facility into the formation (called injection tree), including protection fluids, such as inhibitors for corrosion or hydrate prevention.
- Stop the flow of fluid produced or injected by means of valves in a safe way.
- Control the fluid flow through a choke (not always mandatory).
- Monitor well parameters at the level of the tree, such as well pressure, annulus pressure, temperature, sand detection, etc.

There are two types of Xmas tree according to the configuration of valves, vertical Xmas tree and Horizontal Xmas tree. Figure 14 shows the differences between two configurations.

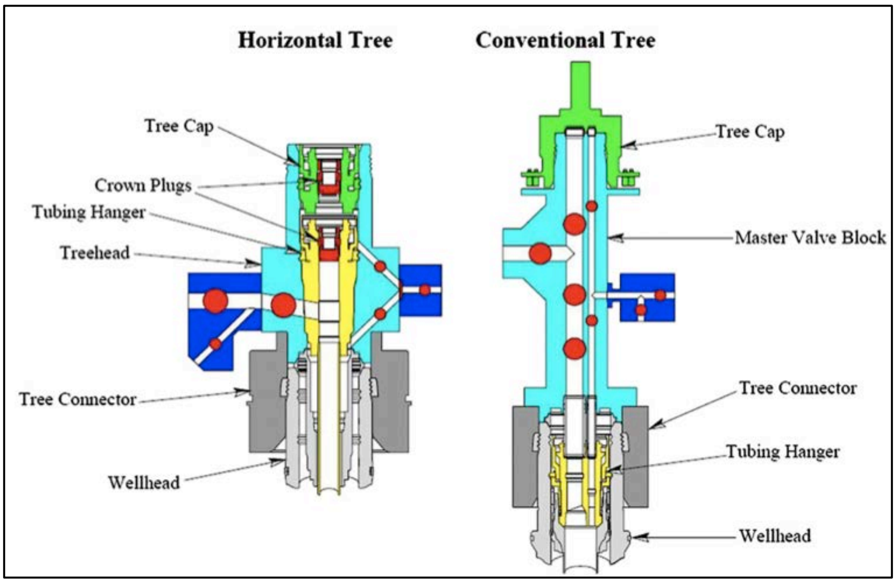


Figure 14 - Difference between horizontal Xmas tree configuration and vertical Xmas tree configuration [17].

Vertical Xmas Tree

The master valves are located above the tubing hanger and swab valves together with master valves are stacked vertically. The production and annulus bore lays vertically on the body of the tree. The well completion is finished before installing the vertical Xmas tree. Since the tubing hanger rests on the wellhead, Xmas tree can be recovered without having to recover the downhole completion. This type is generally applied in subsea fields due to their flexibility of installation and operation.

Horizontal Xmas Tree

In contrast to vertical Xmas tree, the valves of horizontal Xmas tree are located on the lateral sides of the horizontal Xmas tree, allowing for easy well intervention and tubing recovery, thus this type of tree is very feasible for the wells that need many interventions. The tubing hanger is installed in the tree body instead of the wellhead. Consequently, the tree is installed onto the wellhead before completion of the well.

3. SUBSEA WELL ACCESS METHODS IN DEEP WATERS

Subsea well intervention in deep water requires a vessel or a rig and a subsea system to access the wellbore. The floating vessel not only supports the surface equipment for Wireline, CT or HWO, but also should have the capability to handle the subsea system. These are the requirements that determine if the floating vessels can be other than a rig. It is therefore important to understand the conventional subsea intervention approach of utilizing a subsea riser and the alternative riserless method [5]. This chapter will explain interventions with rigid riser system and riserless light well interventions.

3.1 Riser Based Well Intervention

Connecting to a subsea wellhead via a rigid workover riser package that has direct connection to the surface intervention equipment is the most frequently applied method in deep and ultra deep waters. A workover riser provides an extension of the wellbore to the surface enabling well access at the full pressure rating and diameter of the downhole completions [5].

Conventionally, any intervention operation performed via a drilling rig requires the use of a large marine riser, normally with a diameter of 21 inches, connected to a traditional BOP and installed on top of the subsea tree. A pressure-containing workover/intervention riser is deployed inside the marine riser (Figure 15).

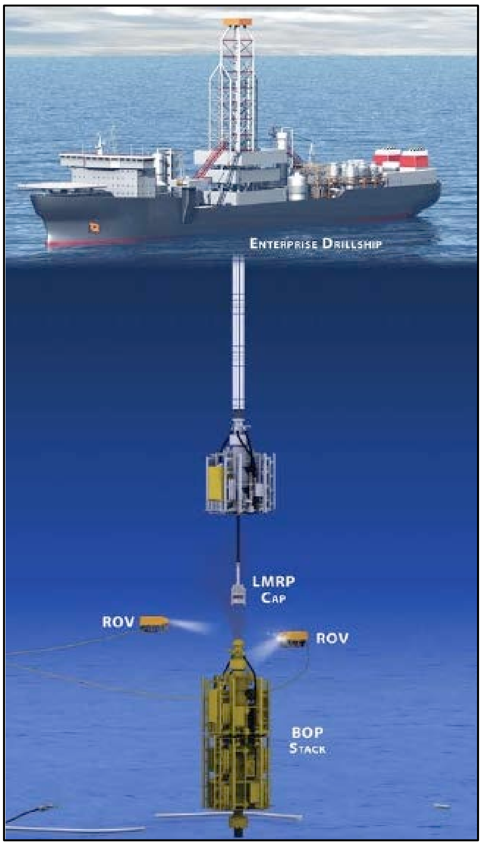


Figure 15 - Subsea well with a BOP and access by utilizing a drillship and marine risers [19].

However, utilization of monohull vessels and the developed technology provides a more efficient solution based on a high-pressure riser operated without the marine riser and seabed BOP. The high-pressure riser is attached to a lower riser package (LRP) that is combinations of a well control package and emergency disconnect package. This is connected to a small BOP located just below the surface installation i.e. not at the seabed or on the vessel. This type of design is not only installed much faster than the traditional equipment but also capable of handling all subsea wireline, coiled tubing, well cleaning, well testing and pumping services and is applicable up to 3000 m water depth [20].

A tensioning system supports the top of the riser system, in addition, a derrick and associated handling system is employed for deploying and retrieving the riser system. Intervention operations are performed from designated areas on deck and items attached to the workover riser surface tree, such as the coiled tubing injector can be supported with an additional motion compensation system. Passive heave compensation systems with a considerable load carrying capacity that increases with water depth are required with the riser system [5]. Figure 16 gives the overview of the riser system described above.

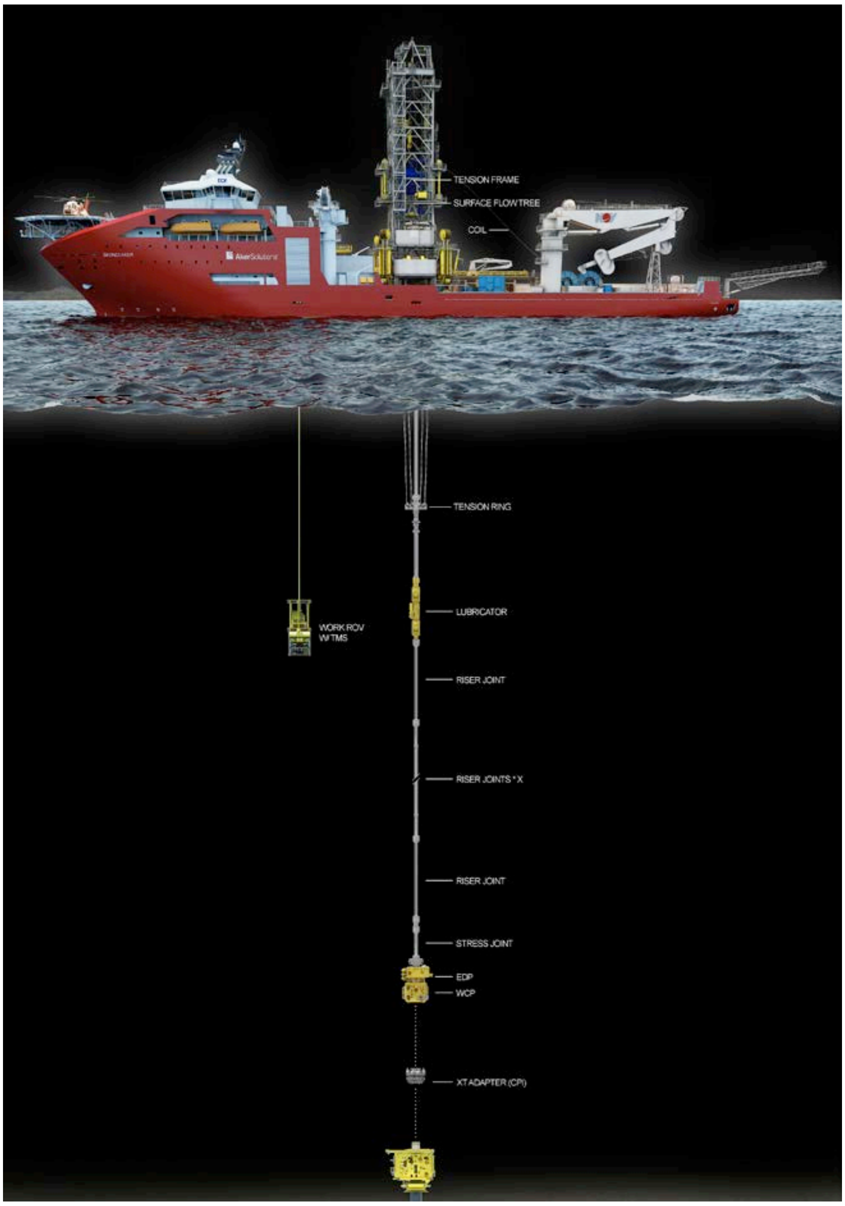


Figure 16 - LWI vessel connected to a subsea well and the lay out of the whole riser system (obtained from Aker Oilfield Services)

The system can be split into 6 parts, starting from top of the Xmas tree up to wireline or coiled tubing equipment at the surface facility:

- Lower riser package
- High pressure riser
- Lubricator valve
- Tension riser joint and tension ring
- Landing riser joint
- Surface flow tree and tension frame (in the tower)

Lower Riser Package

Well Control Package (WCP) attached to Emergency Disconnect Package (EDP) is called Lower Riser Package. This part is designed to isolate well from personnel and riser. It provides pressure control barriers such that it provides the ability to close the well against fluid and gas pressures, and can be used on any design of subsea Xmas tree.

EDP allows for safe disconnection from the well during the operation, when necessary. It is integrated with the vessel's safety system and can be operated from the control cabin on the deck. When the EDP is disconnected from the LRP, it isolates the riser from the environment. A production retainer valve and the annulus master valve shut in the riser. A crossover valve allows circulation of the riser after disconnection.

The retainer valve that is located in LRP acts as the main barrier.

High Pressure Riser

The high pressure riser is a standard riser assembly, handled by standard riser handling equipment as found on modern drilling rigs with catwalk machines, feeders and drawworks all operated remotely from the operating control cabin.

Lubricator Valve (LV)

The lubricator valve's function is to seal and hold pressure in both directions. This valve is the other main barrier together with the retainer valve.

Tension Riser Joint and Tension Ring

The tension ring is connected to the tensioners holding the weight of the risers by fiber ropes. By attaching the tension ring to the tension joint, the tensioners compensate the movement and keep the joint in tension at all times, preventing buckling and twisting forces as the vessel moves with the waves.

Landing Riser Joint

This section is hung at in the work floor, below tension frame and surface flow tree. The rigid riser ends at the flex joint/gimbal and is open to the environment.

Tension Frame and Surface Flow Tree

Tension frame is designed to hold both wireline frame and coiled tubing injector head. It has a small crane to assist tool deployment into the well. It carries a part of the riser load and moves with its own tensioner system.

Surface Flow Tree (SFT) with swivel supports the riser system and provides a means of surface well control when performing live well intervention operations. Two wing valves connect to the choke and kill manifolds to control the flow of the wellbore fluids. SFT provides at least two surface pressure barriers. It allows tools to be introduced and run into the well through the swab valve.

3.2 Riser Based Well Intervention in Operation

This section gives the sequence of the operation steps while deploying the subsea stack with purpose of performing wireline or coiled tubing operations on a subsea well. The description is based on that the operation is taking place on a monohull LWI vessel.

As a first step, LRP is placed in the moonpool area after being pressure tested on its parking location. First high-pressure riser is connected to the top of EDP and the stack is lowered through moonpool into the sea by the help of a guiding frame, which is called cursor frame. Risers are run until the LV point. The number of the risers depends on the water depth and they are pressure tested with water in intervals. After attaching the lubricator valve on top of the lowered riser system, tension joint is connected and lowered together with tension ring. At this point, tension ring is attached to the tensioner system by fiber ropes in order to free the movement of riser system from wave movements. Above the tension joint, a tension frame that holds the wireline tower and coiled tubing injector head is connected to another tensioning system. Then, SFT is connected to the bottom of the tension frame. The top of the landing joint is attached to SFT and bottom of the joint is connected to the rest of the riser system. When all the risers are in place, the weight of the stack is distributed between the tensioner systems, freeing the heave compensated winch that is used to deploy all the risers. Then the vessel is positioned over the well and LRP is landed on Xmas tree. After connecting LRP to the Xmas tree by means of Remotely Operated Vehicle (ROV), an over pull test is applied to check if the riser system is connected. During the riser deployment process, annulus line, nitrogen injection line and methanol injection line umbilical are attached to the riser by clamps, if required in the operation. The umbilical are connected by ROVs.

3.3 Riserless Well Intervention

In this method, the subsea wells are intervened basically by lowering the intervention equipment into the sea by a wireline that is paid out from a dynamically positioned monohull vessel.

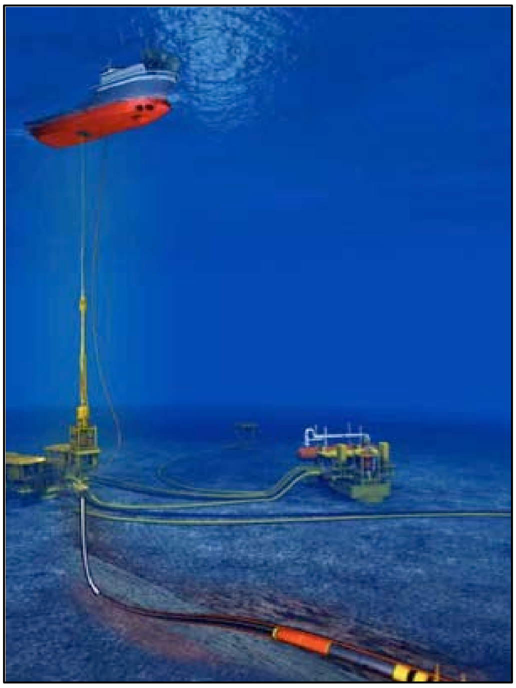


Figure 17 - RLWI vessel accessing a subsea well

The first applications started in Norwegian Continental Shelf by Statoil in 2003 with the purpose of reducing high costs of a drill rig performing the same operations. Statoil led the technology in corporation with other service companies. Since then the technology has been developing rapidly [10]. RLWI operations are applied from shallow to medium water depths, commonly up to 600 m. However a few operations in the Gulf of Mexico have been performed up to 900m and logging demonstration for open-hole at approximately 3000m has been performed with a similar solution. Yet the existing concept is not the definitive technical solution. This concept still has room to be improved with regards to efficiency, weather sensitivity and – last but not least – deep-water compatibility. According to [21], it is envisaged 3000m (10,000ft) water depth is well within reach.

The system is compatible with both horizontal x-mas tree and conventional x-mas trees. All wireline activities are applicable by this method. Although there have been trials for coiled tubing, it has not been successful yet. The regular well operations may involve bringing new wells on stream, preparing old wells for sidetrack or re-completion, logging production contributions from various well zones, plugging water production, perforating new production zones or finding and repairing leaks [10]. As more experience was gained, more developments occurred with more complex downhole tasks. The following is the list of the operations performed so far [21]:

- Data gathering (production logging tool, or PLT)
- Perforating/re-perforation
- Zone isolation (plug/straddle)
- Inspection/repair/installation of insert downhole safety valve (DHSV)
- Milling of short-scale bridges
- Camera runs: visual or X-ray
- Well kill operation
- Pumping operations/scale treatments
- Selective tracer injection or sampling
- Change-out of gas lift valves
- Sleeve operations – downhole instrumentation and control systems (DIACS) valves
- Change-out of subsea trees
- Plug and abandon (P&A) operations of subsea wells.

In general, the wireline Blow Out Preventer (BOP) is placed on top of the x-mas tree. The BOP is operated by a multi-bore umbilical. All valves and sensors in the Xmas tree and BOP are controlled by the operator on the vessel. In addition the Tubing Retrievable Surface Controlled Subsurface Safety valve (TRSCVSS) is controlled and monitored by the same system. All operations, including wireline, are run in open sea through the moonpool of the dynamically positioned vessel.

The stack is a combination of many modules, which can be independently installed and retrieved from the seabed. Figure 18 shows the stack configuration that belongs to FMC Kongsberg. The modules shown in the figure are explained below and the technical description is taken from [22].

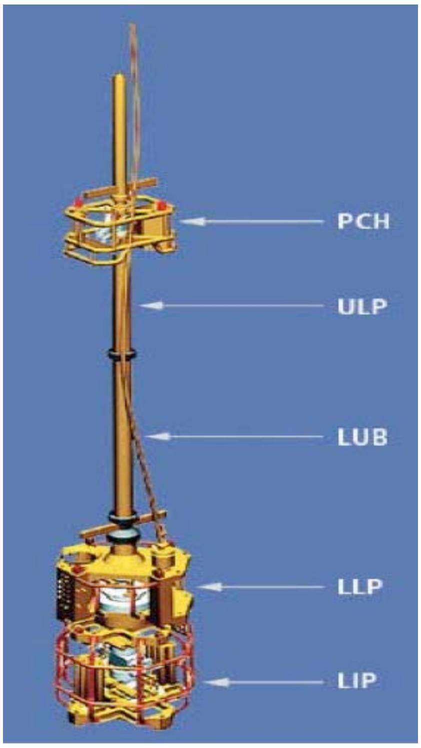


Figure 18 - Configuration of RLWI subsea package [22]

Lower Intervention Package (LIP)

The LIP is placed on top of the XT with the purpose of forming a well safety barrier during intervention. It represents the main barrier element and safety head of the system. LIP is designed to be compatible with both vertical and horizontal Xmas trees. A shear/seal ram with the capacity to cut wireline tools and coiled tubing is included in the LIP. There is a connector, which is located at the bottom of the LIP and this connector locks the assembly to a XT hub. The connector is designed with an interface that is applicable with horizontal and vertical Xmas trees. A subsea tool trap is placed at the end of the assembly in order to prevent accidental dropping of the tool string into the well. Lubricator section starts from the top of the tool trap.

Lower Lubricator Package (LLP)

LLP is located above LIP and below the Lubricator Tubulars in the RLWI stack-up. The LLP acts as the running tool for the LIP and the connection between the control umbilical, well kill hose and control module is. It contains the main control system of the stack, with the controlled module that is located inside. The energy and signals are supplied to the control module form the umbilical. Additionally, LLP consists of a well kill hub and a subsea grease injection system for the wireline.

Lubricator Tubular (LUB)

During pressurization of the system before opening the well and depressurization after closing the well, the wireline tool string, while lowering into or retrieving out of the well, is stored in this place. The storage capacity is up to 22 m long tool string.

The lower part of the lubricator section bends and act as a weak link in the system, in case of excessive forces are applied to the stack in an emergency situation. This will guarantee that excessive bending forces are not transferred from the well intervention system to the permanent installation system.

Upper Lubricator Package (ULP)

Another well barrier element during the intervention operation is the ULP assembly, which is the connection between the PCH and the lubricator. The shear valve block has the capacity to cut all standard, braided wires.

Pressure Control Head (PCH)

The PCH is attached on top of the lubricator and serves as a pressure barrier by sealing the well bore during wireline operations, allowing intervention access to wells under pressure. It represents the primary seal when the wireline is run into the well. The seal around moving wireline is performed by pumping viscous grease between the limited free space in the wireline and the narrow tubes in the PCH. A grease injection system, which is located in the LLP, supplies the grease pressure that must always be higher then the wellhead pressure.

A tool catcher is located at the bottom of the PCH with the function of catching and holding the tool if the tool string is unintentionally pulled into the PCH and the wireline is broken.

Umbilical system

The main umbilical is connected to the LLP with a remote operated multi-bore connector in order to allow an emergency disconnect. The umbilical system is deployed to the seabed together with the LLP/LIP assembly.

Control system

The subsea control system is similar to the one used in intervention with workover riser. It consists of a Workover Control Module, subsea camera, subsea transducers and sensors, subsea jumpers and Xmas tree control valves. The control system is designed to activate fail-safe close (FSC) procedure of valves in the main bore to prevent blowout in case of emergency.

3.4 RLWI System in Operation

This section of the chapter is adapted from [22].

The stack for the RLWI is deployed from the moonpool of the monohull vessel by the assistance of ROV. First, LIP and LLP is deployed with an active heave compensated winch together with guiding wires. The guiding system also supports all assemblies when they are passing through the splash zone.

The sea current may be a crucial force on the wireline tool string while subsea stack is being deployed. Thus, the tool string is continuously monitored in order to avoid twisting of the wireline with the guide or the guideline wires. The tool string is guided by ROVs and guiding cones while entering through top of the lubricator assembly.

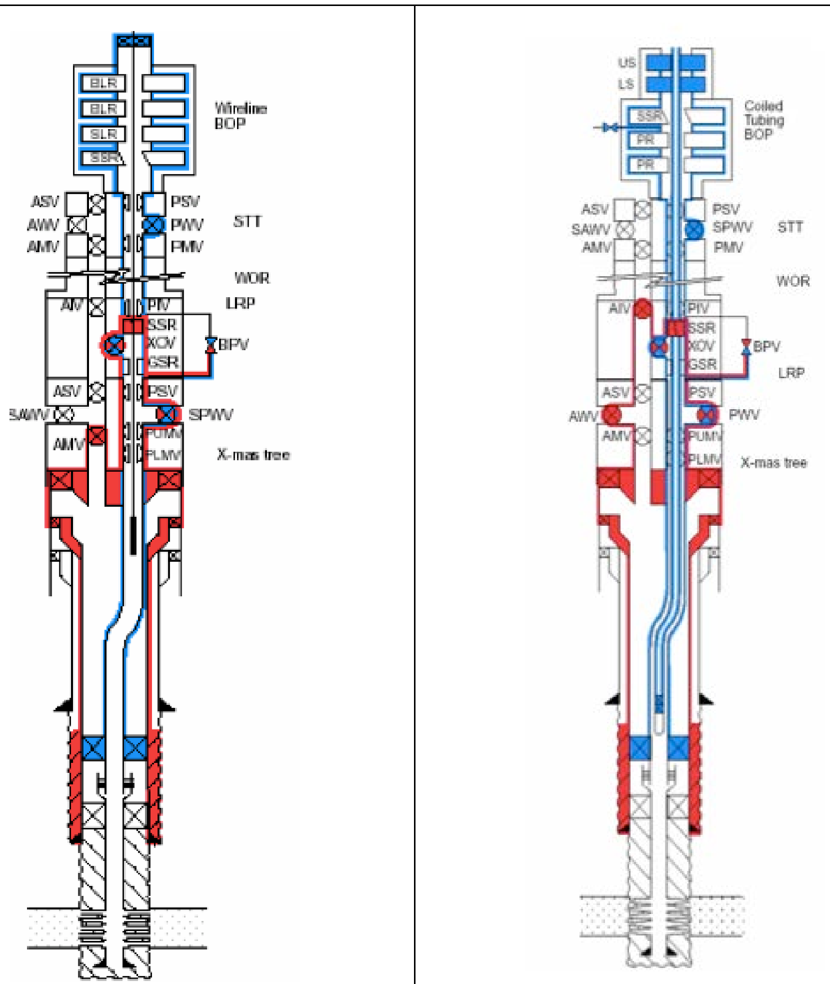
PCH is locked by means of a connector. Afterwards, the seawater in the stack is replaced by an inhibitor to prevent hydrate formation, if the risk exists. This part will be covered in chapter 6 with more details. Next, the stack is pressure tested before opening the well and running the tool string into the well.

4. WELL INTEGRITY AND BARRIERS IN WELL INTERVENTION OPERATIONS

The well barrier is described in NORSOK D-010 [23] as an envelope of one or several dependent well barrier elements (WBE) preventing fluids or gases from flowing unintentionally from the formation, into another formation or to surface. A primary well barrier is the first object that prevents flow from a source. A secondary well barrier is the second object that prevents flow from a source. The secondary barrier is a backup in case the primary barrier fails. A common well barrier is a barrier element that is shared between primary and secondary barrier. The required WBEs with acceptance criteria shall be ready in order to define the well barriers before the operation starts.

NORSOK D-010 also expresses well integrity as the application of technical, operational and organizational solutions to reduce the risk of uncontrolled release of formation fluids throughout the entire life cycle of the well and of course safety aspects.

This study mainly focuses on light well intervention operations performed on a subsea well that are accessed via high-pressure risers. Section 10.8.3 (Figure 19a) and 11.8.3 (Figure 19b) of NORSOK D-010 presents the well barrier elements of wireline and CT, respectively, run through risers, LRP and Xmas tree.



(a) Well barrier schematics of running wireline through vertical subsea production tree with LRP

(b) Well barrier schematics of running CT through vertical subsea production tree with LRP

Figure 19 - Well barrier element schematics for wireline and coiled tubing operations in riser-based systems [23]

The primary barrier elements in a wireline operation include:

- Subsea production tree - Body and production wing valve.
- Lower riser package - Body and production wing valve, connectors, body and x-over valve and by-pass valve.
- High pressure riser
- Surface test tree
- Wireline safety head
- Wireline BOP body, it acts as back up element to the wireline stuffing box/grease head.

The secondary barrier elements in a wireline operation include:

- Wellhead
- Subsea production tree - Annulus master valve, pressure wing valve and the body of subsea production tree
- Lower riser package - Connectors, body, cross over valve, shear-seal ram and back pressure valve.

Lower riser package body, cross over valve, back pressure valve and pressure wing valve on the subsea production tree are common barrier elements.

The primary barrier elements in a coiled tubing operation include:

- Subsea production tree
- Lower riser package - Body, connectors, body and x-over valve and by-pass valve.
- High pressure riser
- Surface test tree
- Coiled tubing BOP – Body with kill valve
- Coiled tubing
- Coiled tubing check valves

The secondary barrier elements in a coiled tubing operation include:

- Wellhead
- Subsea production tree
- Lower riser package – LRP body, cross over valve and back pressure valve.

Lower riser package body, cross over valve, back pressure valve together with the subsea production tree form common barrier elements.

RLWI system, on the other hand is different than riser based system, since there is no riser involved and BOP stack is in direct contact with wireline equipment. Figure 20 shows the barrier schematics with the wireline inside the wellbore. The Xmas tree is barrier tested prior to performing the intervention. The primary barrier throughout the intervention is the BOP stack. Barriers in the BOP are tested before deploying the tool string into the subsea lubricator [10].

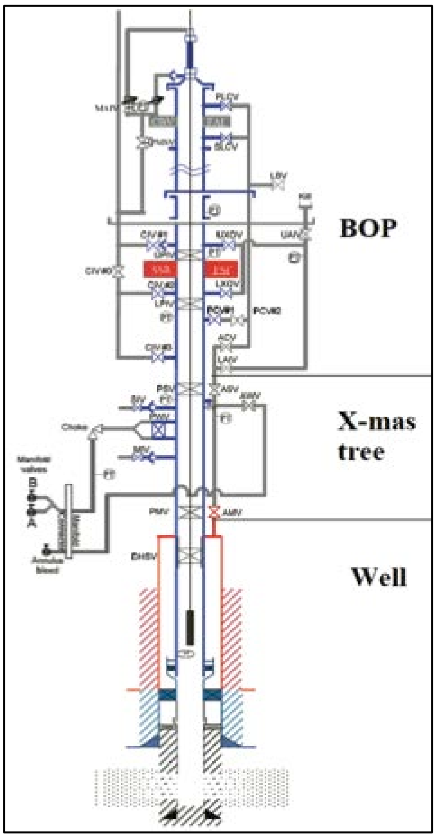


Figure 20 - Barrier schematics with the wireline inside the hole [10].

5. CHALLENGES IN DEEP WATER SUBSEA WELL INTERVENTION

The first challenge in deep water well intervention operations is cost. The most conventional method is to use deep water drilling rigs. Nevertheless, cost of the rigs in addition to availability play a major role on timing of subsea intervention operations. High risk and complexities of subsea wells bring extra cost [24]. Moreover, as the water depth increases, time and cost for tripping to surface and replacing tools increases for surface based systems [25].

The geologic complexity also plays a critical role in deep-water development since complex geologic structures require challenging drilling and completions. In order to achieve the aimed recovery factors and maximize production rates, intervention needs to be integrated to the reservoir development plan. As an example, water injection is the primary method for a deep-water reservoir, which lacks of natural drive energy. However, high level of intervention planning is required due to the problems related to water flooding such as injection conformance, producer water shut-off, scale management and reservoir souring. Well costs are often higher than the facility cost, and well spacing is usually higher than ideal in deep-water development, especially in over-pressured reservoirs [26].

There are some challenges regarding riserless intervention in deep waters. RLWI has proven itself over many years in relatively deep waters up to 900 meters, but currently offers only the possibility to run wireline operations. Use of coiled tubing with riserless deployment in water has been made without success [27]. On the other hand, today's monohull vessel intervention with riser system offers 3000 meters and those vessels are capable of performing both wireline and coiled tubing operations.

The first challenge is maintaining an effective and reliable seal against the wellbore pressure [28]. Sealing may be achieved with elastomer sealing elements (a method similar to the ones used on land applications), if slick line is to be deployed through the lubricator in shallower water depths, up to 240 meters or less. This method was used predominantly for wells, which were in water depths under 240 m, for which slickline provided the sufficient wireline capability.

More complex technology is required when real time/complex wireline tools with e-line are needed in water depths more than 240 m. The method for creating a seal around e-line is not new, such that grease heads have been modified to make them subsea compatible, and this method works well. The major issue is the delivery of grease to the grease head at the top of the lubricator in deeper water. In addition to this, it should be possible to control the pressure of the grease in order to adjust the sealing force to meet varying well conditions. A considerable amount of energy is required for pumping grease any distance in these deep-water applications, from surface to a subsea well, and is not responsive to adjustments made from the surface.

Another challenge introduced in [29] is the length of the cable and forces applied on the cable. The wireline is exposed to the currents in the open water between the ship and the subsea lubricator system, during RLWI operation. As water deepens, the cable length for the tool string gets longer; hence the forces acting upon the wireline may become overloading by acting with an upward force on the tool string inside the well. Depending on the magnitude of the sea current, this force may be able to pull the tool string out of the well.

One more challenge for deep-water RLWI is that how many lines (umbilical and cables) are in the water at any one time [21]. Deploying more lines in close range to each other in the water column brings the issue of tangling two or more lines. In shallow waters, RLWI operations, it is common to have seven to nine lines in the water. The risk of tangling gets higher as the water depth increases. In deeper waters, the number of lines may be reduced if the some of the lines can perform double duties with lighter components and ROV assist. For example, the composite cable can do both the PCH lift line duties and the wireline duties for raising and lowering the wireline tool in and out of the well. Ideally, there should be only three lines at one time in the water for simplicity i.e. installation workover control system (IWOCS) umbilical, the ROV umbilical and the wireline. Fewer lines in the water may also improve the performance of the vessel by means of less heave compensation equipment, further adding to the simplicity and robustness of deep-water RLWI.

Another major challenge in deep water is the hydrate formation. It is an issue for both riserless and riser based well intervention methods, however hydrate formation risk is increased by introduction of water into systems in RLWI [28]. Prevention and recovery from hydrates is a requirement of any deep-water intervention operation [25]. There are various ways to constrain this. The most applied way is to inject sufficient hydrate inhibitor in order to protect valves and tool systems with a dedicated inhibitor injection line. Flushing circuits and valves within the subsea system is essential to be able to flush wellbore fluids (from hydrocarbons) and to treat with inhibitor after tool change-outs, prior to reopening the well. Then again, it should be noted that hydrate inhibitors also cut the grease used in the grease head and unless increased supply of grease can delivered, there is high risk of grease loss in grease seal is high in RLWI [28]. Since hydrate formation, selection and injection of the hydrate inhibitor is a great concern regarding the deep-water intervention operations, it needs to be explained in details in a separate chapter.

6. SELECTION AND INJECTION OF HYDRATE PREVENTION FLUIDS

Hydrates are vital in deep water developments because ambient temperatures are low enough to be in the hydrate formation region at operating pressures. This chapter first explains what hydrate is, how it is formed and the consequences of the formation, then how it can be prevented in deep water interventions by injecting hydrate preventing fluids.

6.1 Hydrates and Hydrate Formation

The crystalline compounds formed by the physical combination of water molecules with certain small molecules in hydrocarbon fluids such as methane, ethane, propane, nitrogen, carbon dioxide, and hydrogen sulfide are called natural gas hydrates.

When the light hydrocarbon meets water at high pressure and low temperature, hydrates starts growing. Although hydrates may appear anywhere and at any time in an offshore system when there is natural gas, water, and suitable temperature and pressure, the problem appear most commonly during drilling and production processes [17].

Although it depends on the region, generally, water temperature at the seabed becomes approximately constant at approximately 4^{o}C when water depth is deeper than 1000 m. Due to this low ambient temperature, hydrates may possibly occur during the shutdown/start-up production in the well and Xmas tree, even though they may not form during normal operation at steady-state conditions in which the flow rate and temperature of hydrocarbon fluid are higher.

The major consequence of the hydrates is plugging the flow lines, valves, and other subsea devices. The presence of water in the hydrocarbon systems may lead to the formation of hydrates when temperature and pressure are in the hydrate formation region. Hydrates keep growing as long as water and small molecule hydrocarbons are present, developing into flow blockages. The blockages eventually time consuming to clear in subsea equipment or flow lines and cause safety problems. When vessel intervention costs and delayed production is considered, lost or delayed revenue and costs associated with hydrate blockages can be significant. Thus, hydrate prevention and remediation are important design factors for deep-water development operations.

There are several methods to prevent hydrate formation including controlling temperature, controlling pressure, removing water, and by shifting thermodynamic equilibrium with chemical inhibitors such as methanol or mono ethylene glycol (MEG), low-dosage hydrate inhibitors (LDHI). Injection of hydrate preventing inhibitors is the most commonly applied method in deep water well intervention, therefore only this method will be discussed in the course of this study.

6.2 Prevention of Hydrate Formation by Inhibitors

There are two types of inhibitors that are used in prevention of hydrate formation; thermodynamic inhibitors and LDHI.

6.2.1 Thermodynamic Inhibitors

Methanol or glycol is most commonly used thermodynamic inhibitors although ethanol, other glycols, and salts can be effectively used.

The pros and cons of thermodynamic inhibitors are listed in [30]. Pros:

- They reduce hydrate formation temperatures.
- Software models are available that predict the effect of an inhibitor on the hydrate formation curve.
- With sufficient quantities, they prevent hydrates under most conditions.
- Some (such as methanol) inhibit both liquid and vapor phases, which is advantageous during transient operations such as production starts up.

- They work for any hydrocarbon system.

Cons:

- Large quantities may be needed.
- Large storage volumes and pumping requirements are often required which can lead to significant capital costs. There may be incompatibilities between the inhibitor and other production chemicals such as paraffin or corrosion inhibitors.
- There may be incompatibilities related to corrosion between the inhibitor and materials of construction such as umbilical.
- The inhibitor may cause salts to precipitate from the produced water.

Both methanol and MEG are organic compounds that are commonly used as an anti freeze. How these inhibitors prevent hydrates forming is very similar to using them as anti freeze. These inhibitors avert the hydrate formation simply by shifting the hydrate stability curve to lower temperatures for a given pressure.

The selection of inhibitor is mostly decided based on economics, downstream process specifications, environmental issues, and/or operator preferences. Deciding on the hydrate inhibitor is an important decision to be made and this decision might involve various criteria [17]:

- Capital costs of topside process equipment, especially for regeneration;
- Capital costs of subsea equipment;
- Topside weight/area limitations;
- Environmental limits on overboard discharge;
- Contamination of the hydrocarbon fluid and impacts on downstream transport/processing;
- Safety considerations;
- System operability;
- Local availability of inhibitor.

6.2.2 Methanol vs. MEG

Both methanol and MEG are very effective inhibitors in deep-water well interventions. Hydrate suppression performance and cost are the most two important factors that make methanol and MEG more commonly used compared to the other thermodynamic inhibitors.

In terms of performance, methanol delivers a higher temperature depression than MEG does. Concentration of inhibitor with 5% of methanol yields 2 ^{o}C of depression while same concentration with 5% of MEG yields 1 ^{o}C [31].

Methanol is much cheaper than MEG, at first glance. A rough estimation of cost for methanol is 300 $ per ton, whereas the cost of MEG is 900 $ per ton. However, methanol loss to gas or condensate phase is much greater. MEG losses are negligible when compared to methanol losses [31]. Roughly, the total methanol loss, with typical 30 % methanol weight in the water phase, is app. 500 kg per 10^6 m^3 gas and 50 kg per 1000 kg condensate. MEG lost to the gas is only is 0.3 kg per 10^6 m^3 gas, independent of the weight % of MEG in the water phase. In situations with excessive water production, treating with methanol becomes uneconomical or infeasible. Moreover, methanol losses also increase noticeably as the temperature increases.

Viscosity of MEG is significantly higher than viscosity of methanol, especially at low temperatures, which is the case for the most deep-water regions. In this case, a MEG injection system needs a larger diameter injection line and/or more pumping horsepower.

The last but not the least concern is safe use of methanol [31]. It has flash point at 11 ^{o}C and is highly flammable. Furthermore, methanol burns with an invisible flame, making fire detection a more difficult problem. On the contrary, MEG is non-flammable, with a flash point at 111 ^{o}C. This clearly indicates that methanol presents a greater safety risk with respect to handling and storage (especially on offshore installations with limited area).

6.2.3 LDHI

These types of inhibitors are divided into two groups: anti agglomerants (AA) and kinetic hydrate inhibitors (KHI). They can prevent hydrate blockages at significantly lower concentrations (e.g. less than 1 weight percent) than thermodynamic inhibitors [30]. LDHIs prevent hydrates by interfering with the formation of hydrate crystals or the agglomeration of the crystal into blockages instead of changing the hydrate formation region.

AAs constrain hydrate plugging rather than hydrate formation by permitting hydrate crystals to form but keep the particles small and well dispersed in the oil phase. They can provide relatively high sub cooling, sufficient for deep-water applications. There have been successful field trials in deep-water GoM production systems. The type of oil, the salinity of the water, may affect the effectiveness of AAs.

KHIs work by inhibiting hydrate formation in the water phase only and therefore are water soluble or dispersible. They appear to work independently of the water cut. Still, they can currently only be applied for relatively low sub cooling and this is not appropriate for deep-water. For deep-water oil developments, AAs are more applicable because of the higher sub cooling.

Although there is no use of these inhibitors in deep water well intervention operations, they are used in the GoM and on the UK sector in other hydrate prevention situations. There are serious limitations in low temperatures. AAs generally require a certain amount of condensate (continuous oil phase) in order to be effective. KHIs can only give a limited suppression of the hydrate formation point, and they are not proven to be fully effective at higher pressures, hence not suitable for deep-water at all.

6.3 Hydrate Remediation

Methanol and MEG are not only used for hydrate prevention but also used for removal of hydrate blockages. The challenge in application of methanol or MEG lies in getting the inhibitor in contact with the blockage [17]. Injecting can be effective if the injection point is located relatively close to the blockage. However, this may not always help with dissociating a hydrate blockage, though it may prevent other hydrate blockages from occurring during remediation and restart. The most applicable intervention method would be accessing with coiled tubing, and then methanol can be pumped down the coiled tubing to the blockage.

There are two main factors making hydrate plugs exceedingly difficult to remove:

- Large amount of energy requirement for dissociating the hydrate, and heat transfer through the hydrate phase is slow.
- Hydrates also contain large volume of concentrated natural gas such that 1 ft^3 of hydrate can contain up to 182 ft^3 of gas. This might cause significant consequences for safety in depressurizing hydrate plugs.

Other hydrate remediation techniques are similar to hydrate prevention techniques, which include:

- Depressurization from two sides or one side, by reducing pressure below the hydrate formation pressure at ambient temperature, will cause the hydrate to become thermodynamically unstable.
- Active heating is used to increase the temperature to above the hydrate dissociation temperature and provide significant heat flow to relatively quickly dissociate a blockage.
- Mechanical methods such as drilling, pigging, and scraping have been attempted, but are generally not recommended. Methods include inserting a thruster or pig from a surface vessel with coiled tubing through a workover riser at launchers, and melting by jetting with MEG.
- Replace the pipeline segment.

6.4 Methanol or MEG Injection in Well Intervention Operations

The most practical approach is to dedicate a line to ensure adequate inhibitor injection to protect subsea BOP (if existent), valves and tool systems during the intervention operation. Flushing circuits and valves within the subsea system are required in order to provide flushing wellbore fluids (from hydrocarbons) and treating seawater with inhibitors t prior to reopening the well after tool change outs. The injection applications differ in riser based and riserless intervention systems.

6.4.1 Riser Systems

This section aims to describe how the inhibitors are handled prior to injection in a riser-based system such as described in chapter 3. Generally, methanol is selected for riser based systems, yet the configuration of the injection system should not be different for MEG.

The common practice is that the methanol is transported and delivered onboard in stainless steel containers and stored in the tanks that are also made of stainless steel. The whole methanol injection system is composed of storage tanks, injection tanks, and injection skid with injection pumps. Prior to the injection process, methanol is transferred from storage tanks to dedicated tank for injection by means of transfer pumps. Methanol injection line exiting from the injection skid is attached to the SFT by a hose or umbilical. Methanol is injected by opening the relevant valves to the aimed injection points by using the methanol injection pump that is located on the methanol injection skid.

The system should be pressure tested before the injection starts.

6.4.2 Riserless Systems

The MEG injection system developed as part of the RLWI technology is used to protect the RLWI stack. In the first applications of RLWI, the biggest concern was hydrate formation on the braided cable entering or exiting the top of the PCH, which contained wireline stuffing box, tool catcher, grease head and chemical injection cavities and a connector to lock and seal on the lubricator [21]. In order o compensate the expected problem; grease and MEG injection rates and cavities between seal units in the PCH at the top of the lubricator assembly were overestimated. Current applications prove that hydrate formation can still be avoided even though the injection rates are reduced by 80–85.

The configuration of MEG injection system for hydrate remediation and chemical treatment is as same as the grease injection configuration [21]. A second electric control system that is mounted on the same base, adjacent to the grease injection, controls the MEG injection system. Unlike inhibitor injection system in riser systems, MEG storage tanks are mounted circumferentially around the lubricator tube (Figure 21). MEG is then pumped from the storage tanks up to the PCH or down to the LIP and LLP for chemical injection treatment. MEG is stored in large volumes because it is also used for flushing the lubricator besides hydrate remediation and chemical treatment.

This type of RLWI equipment is designed in a way that no hydrocarbons will be returned to the surface vessel. The lubricator stays with LIP and LLP on the seafloor, both while the wireline tool is inserted in the lubricator and later recovered from the lubricator. On top of this, the bore of the lubricator switches from ocean environment to hydrocarbon wellbore, and then back to ocean environment again. In order to do so, the lubricator has to be flushed and equalize the pressure during the transition. Hence, MEG is injected to treat seawater as the lubricator opens up to the wellbore. Before removing the PCH, opening the lubricator back to ocean environment and recovering the tool, hydrocarbons are displaced out of the lubricator (and wireline tool) and back into the well.

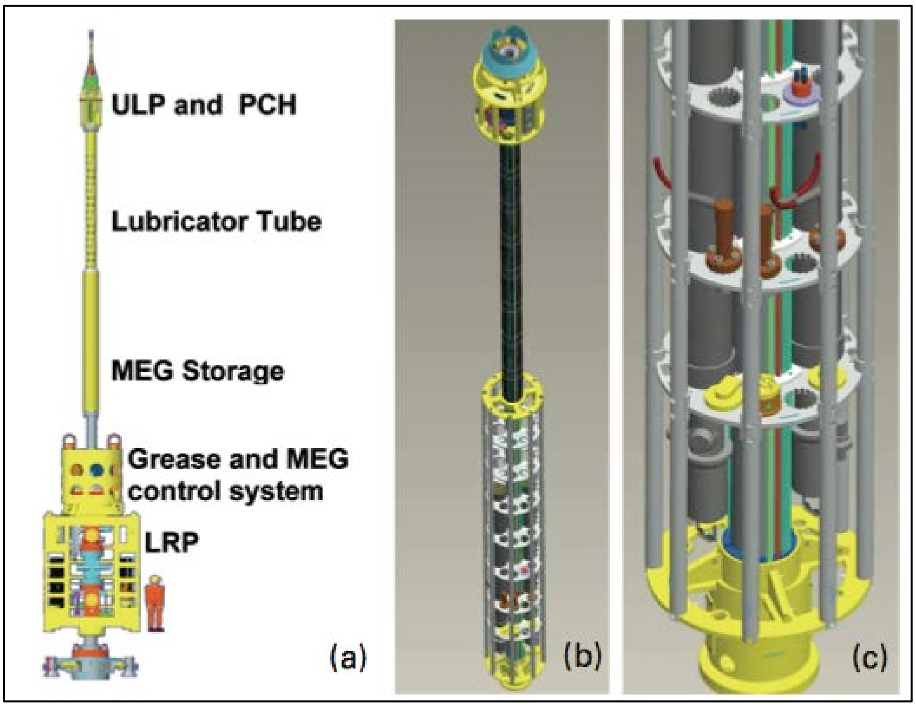


Figure 21 - Deep-water MEG injection system [21]

The volume of MEG stored on the lubricator is determined according to the number of tool entries and exits. In case of more MEG requirement, lubricator may be recovered for recharging MEG while leaving LIP and LLP closed and locked on the Xmas tree.

6.6 Risks of Methanol and MEG

General risks involved at using thermodynamic inhibitors can be listed as [30]:

- Underdose, particularly due to not knowing water production rates;
- Inhibitor not going where intended (operator error or equipment failure);
- Environmental concerns, particularly with methanol discharge limits;
- Ensuring remote location supply;
- Ensuring chemical/material compatibility;
- Safety considerations in handling methanol topside.

Besides those risks, both methanol and MEG are toxic liquids such that there shall be no skin contact and no inhalation of the vapor. Personal precautions include keeping people away from any leakage and breathing the vapor. Additionally, they should not be released into environment; any leakage should be prevented if it is safe to do. Material Safety Data Sheets (MSDS) of methanol and MEG are attached in APPENDIX .

Methanol may be extremely dangerous compared to MEG because it is highly flammable. Burning with invisible flames makes the fire detection extremely difficult. In case of fire, it can be extinguished by water spray, dry powder and foam. In this type of situation, it is extremely crucial that the fire fighters wear a self-contained breathing apparatus in addition to protective suit.

As an example, fire and gas system of the methanol injection system described in section 6.4.1 can be presented here. The methanol storage tanks are covered by fixed firewater system, which is connected to main firewater system. In addition to the fire water system, the storage tanks are also connected to two dedicated flame detectors. One flame detector will provide fire alarm with start of fire pumps, while both flame detectors together will also initiate automatic emergency shut down (ESD). At least two portable gas-measuring units are available on board for detection leakages. They can measure

Oxygen level and hydrocarbon level. Similarly, methanol injection skid is covered by a fixed fire water system, in addition to two flame detectors functioning in the same procedure as the other two flame detectors.

7. EXAMPLES OF SUBSEA WELL INTERVENTION APPLICATIONS IN SHALLOW AND DEEP WATERS

In this chapter, some subsea well intervention operation cases are presented to explain how the operations are achieved and how the obstacles are coped with concerning water depth and/or technology.

7.1 Wireline Operation On a Subsea Well With a Jack Up Drilling Rig

This first case is selected in order to demonstrate the difficulty of accessing a subsea well with conventional methods and finding an available floating unit to perform the job.

The wireline was done on the Seahorse-1 subsea oil well, which is located in 45 meters of water and completed with a vertical tree. Exxon Mobil’s subsidiary Esso Australia Pty Ltd. performed the operation [32].

The objective of performing a wireline operation was to isolate the lower producing zone from the upper producing zone through tubing so that the upper zone could be produced more effectively. The production rate of the well was 150 BOPD (barrels oil per day) at 95% water cut from the two-stacked commingled zones before the intervention. Core data showed that the lower zone had over five times the permeability of the upper zone and the flow tests showed that the gas-oil ratio (GOR) of the upper zone was 20 times higher than the lower zone. Based on the producing GOR, the upper zone was contributing less than 10% of the total flow from the well, it was concluded that the more permeable lower zone dominated the commingled flow leaving unproduced reserves in the upper zone.

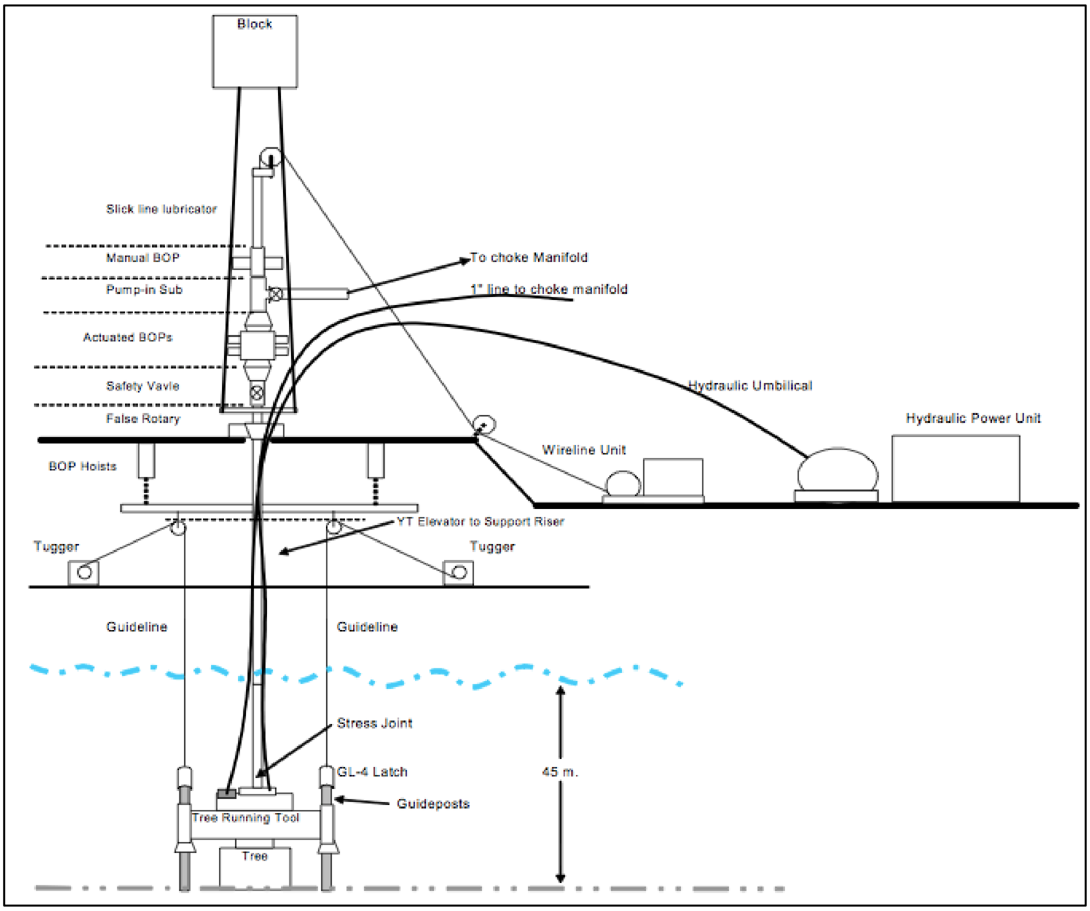


Figure 22 - Schematic of the rig up that was used in the wireline operation [32]

A wireline drift was run to the bottom of the well to find clear access to all production zones after establishing a conduit from the rig to the subsea well through a workover riser (Figure 22). First trial of closing the lower sliding sleeve was not successful. After this attempt, a through-tubing plug was set to isolate the lower zone. After isolating the lower zone, a production logging tool string was run into the well in order to determine the production rate and composition. During this flow test, the upper zone produced dry oil, consequently confirming the outcome for this well intervention. The workover riser was then removed and the well successfully brought to production back to Barracouta platform with 4000 BOPD. The operation was completed in 16 days with no recordable incidents. Some non-productive time (1.9%) was incurred due to strong winds and high sea states that occurred prior to moving the rig off location at the end of the job.

There were several challenges such as the condition of the 16 year-old subsea equipment that had not been used since installation. A number of modifications had to be made to the rig to facilitate the subsea operations and the modifications were identified 4 months prior to the operation. A frame was designed and built for the launch and recovery system. The hatch that is used to lower equipment (typically BOP sections) into the cellar deck was partially obstructed by pipe work that was modified to allow the tree running tool (TRT) to pass easily through the hatch. In addition, there was no sufficient time to install spider beams that enable the TRT to be positioned over well center while the guidelines and riser are attached. Hence, an adaptor frame was designed to suspend the TRT below. There was no tensioning system to keep the workover risers in a vertical position, thus a tensioning frame was designed and built to maintain riser tension by suspending the frame (and riser) from the rig blocks. Besides the technical disadvantages, positioning the rig around subsea equipment was another challenge. The seabed surrounding the wellhead is a nearly flat, hard sandy base that resulted in minimal penetration (~ 4 feet) by the jack-up legs. In the vicinity of the wellhead, the seabed was covered with equipment and pipelines that could be damaged by, or cause damage to, the jack-up rig's spud cans.

7.2 Riserless Light Well Intervention Application in Åsgard Field in North Sea

This case demonstrates the application of scale milling technology applied by a RLWI vessel (Island Frontier). The operation was performed at Smørbukk, one of the discoveries of Åsgard development, a high temperature gas condensate field, producing from five independent reservoir layers [33].

The scope of the intervention was to remove a 23 m calcium carbonate scale bridge (Figure 23) to provide access for installation of a high-pressure high temperature (HPHT) bridge plug and permit subsequent additional perforation work. An electric wireline conveyed tractor with a rotational assembly was chosen to perform the job.

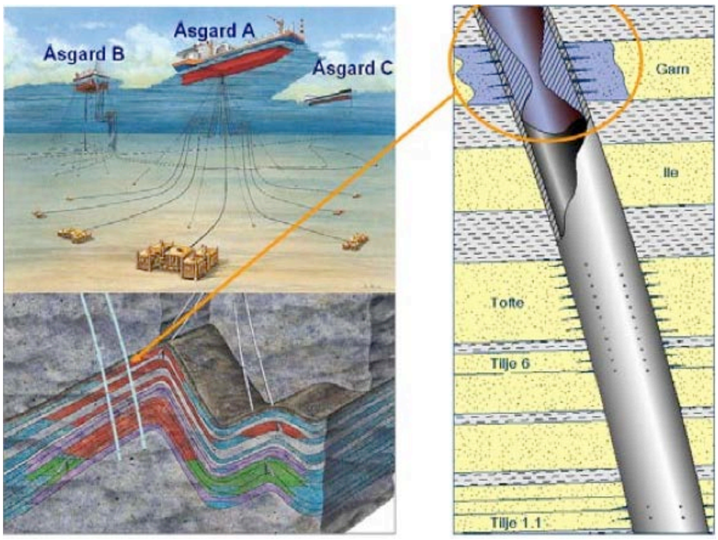


Figure 23 - Overview of Asgard Field with illustration of scale deposit [33]

Three milling runs were performed to mill through the scale bridge and each wireline run were performed by deploying the wireline bottom hole assembly (BHA) and the PCH in open sea. The BHA is lowered into the lubricator and the PCH is locked onto the ULP. Although the same milling assembly was used for all three runs, a new wireline tractor was required on each run.

900 m long umbilical was connected to the workover control system container that was placed onboard the vessel. The subsea grease system and the control function of the stack were operated through this umbilical. Throughout the lubrication of the wireline BHA, all hydrocarbons were flushed into the wellbore. The only connection to the vessel was through the main umbilical and the wireline cable.

MEG was continuously injected into the well during the milling operation, at varying rates from 14 liters per minute (lpm) to 30 lpm to remove scale debris around the milling bit and reamer. The scale was located in the near vertical section (2-3°) of the well, therefore the rate of MEG injection was considered to be sufficient. When the progress started to drop, the injection rate was reduced to 14 lpm. During milling, pick-up weights were taken every meter. The rotation counter, confirming if the milling assembly was rotating or not, was included in the wireline tractor assembly for all of the three runs.

The operation took the same amount of operation days as a semisubmersible rig would take. However, the overall cost was 50% of the estimated cost of a CT operation from an intervention vessel, mainly due to the low day rate of a RLWI vessel. In addition there is a significant value in the accelerated oil production realized compared to what would have been achieved if it was necessary to wait for a suitable semi submersible rig with coiled tubing to be available. The production results from the well showed the production rate increased from 468 Sm^3/d to 1204 Sm^3/d.

This case proves that RLWI combined with scale milling technology is a method that can be used on subsea wells instead of using a semi submersible rig with coiled tubing.

7.3 Retrieving Coiled Tubing Stuck Due To Hydrate Formation in Ultra Deep Water

This case is an example of problems that occur because of hydrate formation.

A well testing operation was performed on a gas well, which was drilled from a semi-submersible drilling rig in 1725 m water depth, in Mexico [34]. The well test was performed from the semi submersible rig, however, a dynamic positioning environmental process boat was also contracted to receive all fluids during the test.

In order to perform the test, firstly, a drillstem test string (DST) with a $7^{5/8}$ in. packer and TCP gun was run into the wellbore. Secondly, coiled tubing injector head was rigged up (Figure 24). Glycol was started to be injected with a rate of 16 liter/hour through the injection nipple located below the sub surface test tree at 1717 m. The coiled tubing was tripped into the well to perform jet lifting with nitrogen and natural gas flow through the choke manifold. No response was seen from the jet lifting application, and then diesel was pumped through the coiled tubing. The tubing was stuck and a massive hydrate plug was confirmed when the coiled tubing was being pulled out of the hole. Tension was applied in order to release the tubing, but it was unsuccessful. After this unsuccessful attempt, it was decided to kill the well. Brine and glycol mixture was injected through the coiled tubing after well kill, with the purpose of disassociating the hydrate plug. It partially worked, but not good enough to remove the plug. Coiled tubing was perforated at a few points to confirm the top of the plug by providing reverse circulation after the perforation. More glycol was injected through the perforations, but it was unsuccessful attempts again. Then, nitrogen was circulated through the hole to eliminate the hydrostatic pressure above the hydrate plug in order to disassociate the plug. Injecting nitrogen by reverse circulation to clean up and eliminate hydrostatic pressure, and burning the gas released from the hydrate was applied several times. After 11 days, the coiled tubing experienced a partial movement. Then coiled tubing was perforated at a few more points, as a gas trap was discovered below the hydrate plug. The gas was bull headed in to the formation. After pressure was applied in the annulus, coiled tubing was freed from the hydrate plug. Then the remaining of the hydrate was removed by reinstalling the coiled tubing with a bit and mud motor.

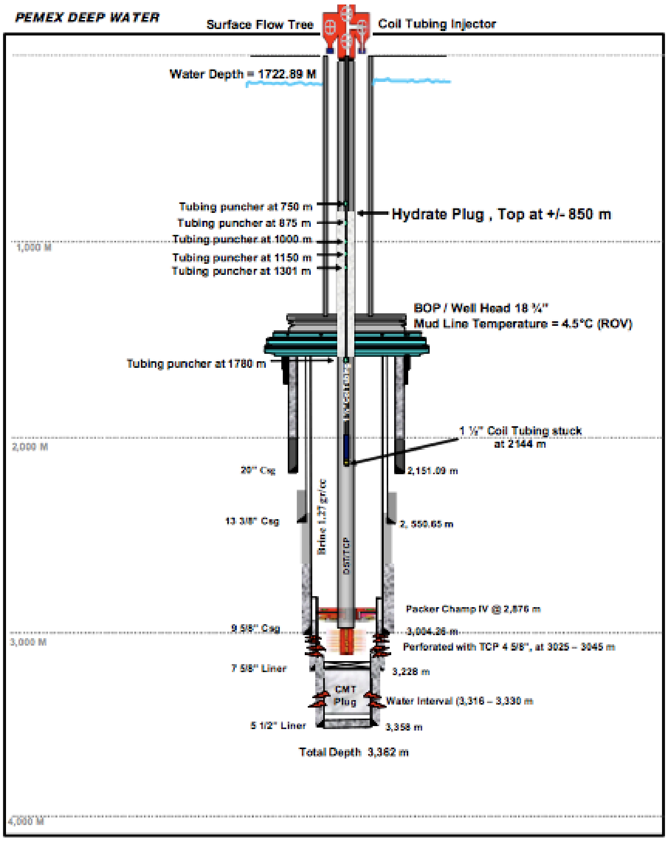


Figure 24 - Coiled tubing configuration [34]

This case makes it clear that hydrate formation is a great risk in deep waters and it may cause great problems that are highly cost. Deep-water operations require thorough planning in addition to comprehension of hydrate formation.

8. DISCUSSIONS AND CONCLUSION

Deep-water subsea well intervention is visibly a great necessity with a few challenges that should be overcome by the rapid development in deep-water technology. It is very clear that field developments are moving deeper each day, as the oil companies are in need of more resources. Considering the majority of the deep-water fields are developed with subsea wells, intervening subsea wells becomes a need despite the challenges.

The most obvious challenge is the cost of the operation. Traditional method is utilizing semi submersible drilling rig, which have extremely high day rates and are unavailable most of the time. The excessive rig up time of these rigs also adds up to the cost of operation by adding more day rate. Moreover, tripping time is a major concern with these rigs, as the water gets deeper, the number of riser joints tripped increases.

The issue with these rigs brought up a new solution to well intervention industry. Currently, it is very possible to utilize dynamically positioning monohull vessels for working on subsea wells as deep as 3000 m. The cost of an intervention operation can be reduced drastically since day rate of these vessels are half of drilling rigs. They can travel much faster from one well to another, besides the rig up time is significantly shorter than of a drilling rig. These vessels are capable of performing any light well intervention operation by connecting the subsea well via high-pressure risers. Furthermore, design of these vessels enables to receive hydrocarbons on board for well testing purposes.

Cost of light well intervention operations may be even more reduced by applying riserless well access methods. Dynamic positioning vessels for riserless operations are even smaller than LWI vessels since less deck space is required and they offer much less day rates. RLWI is extensively applied in North Sea, and there were a few applications in GoM. Despite the cost effectiveness of this method, it has various limitations compared to riser-based interventions. Wireline operation is the only option at the present; hence it should be enhanced to perform coiled tubing operations. There is also room for improvement regarding the water depth limit and sea condition.

As monohull vessels seem like good solution for reducing the astronomical operation rates, they are still limited to light and medium well interventions. There is still a gap for a relatively cheap and efficient heavy intervention method. Statoil has recently taken the first step in cooperation with Aker Solutions to fill this gap by a new dynamic positioning rig, Cat B. Cat B is planned to have all the advantages of a monohull vessel while it will be able to perform all type of interventions including hydraulic work overs and through tubing drilling.

Second major challenge is preventing hydrate formation. It is extremely crucial to comprehend hydrate formation and methods for prevention in deep-waters, since it can be a total sabotage to the operation. Although there are a few methods for preventing hydrates in all subsea structures, thermodynamic inhibitor, especially methanol and MEG, injection seems to be the only application in deep-water well intervention operations. LDHI usage has been proved to be a very effective in preventing hydrate formation for long term injection, yet there is no application of LDHI in any type well intervention. Methanol is the most used inhibitor due to its high effectiveness and considerably low cost. Both methanol and MEG are toxic fluids more to the point; methanol is far more dangerous compared to MEG. It is extremely flammable as a result of low flash point, creating a high risk of fire. MEG is slightly less effective than methanol, but it would be the best suggestion for intervention applications due to low risk of fire.

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APPENDIX A

This appendix outlines the details of wireline; tools used in wireline operations and coiled tubing equipment.

Wireline Equipment

The equipment lay out for both slickline and braided line was demonstrated on Figure 3. Below are a more details about this equipment shown on the figure. Technical descriptions are adapted from [22].

Stuffing Box

The stuffing box is used to run the wireline through the lubricator, which is exposed to well pressure. The wireline passes through the sheave wheel and runs through packing in the stuffing box body.

The stuffing box joins with a plunger, which seals the flow in case of a packing failure or wire breakage. Stuffing boxes also include a quick union connector that can be connected to the lubricator.

Lubricator

The lubricator is a pressurized cylinder that allows lowering and lifting the wireline service tools from a well without well kill process. The lubricators enables the wellhead valve open and close, hence allowing the wireline tool string running or retrieving from the wellbore prior to and after the wireline operations, respectively.

The lubricators length covers the entire work string. The sections are joined together by quick unions that can be tightened by hand, and are practically impossible to open while under pressure.

Blow Out Preventer (BOP)

The BOP, also referred as well control package, is a ram-equipped stack that involves different valves, which prevent or control blowouts. Minimum two rams are used in series, or a dual ram with the same functions may be used instead. One of the rams closes and seals around the wire, isolating the well pressure from the lubricator section, while the other ram is a shear type ram and cuts the wire in emergency situations.

Wireline Unit

The wireline unit is composed of a drum and a control panel. The drum is driven by an electric or hydraulic motor and holds the wire that is used to run the tools in and out of the well. The control panel enables to operate the wireline unit hydraulically. The length of the wire stored on the reel depends of the wire diameter.

Hydraulic Power Pack

Sufficient pressure and flow rates are supplied by the hydraulic power pack to the wireline unit. It is driven by a diesel or electrical motor.

Measuring device

The measuring device shows the length of paid out wire, and provides the operator with valuable information regarding the tool depth.

In addition to the measuring device, there is also a weight indicator, which is used to monitor the load on the wire. It is a crucial device in pulling operations in order to protect from equipment failure.

Control Cabin

The control cabin is used to control functions of the reel and the BOP and metering parameters such as weight on the reel and paid out wire length are displayed on dials in the cabin.

Tool String

The basic tool string for wireline operations consists of: rope socket, stem (weights), jar and different tools that can be combined with the string. Technical description of the tools listed below is taken from [7, 22].

Rope Socket

It is the fundamental link between the tool string and the wire and uppermost component in a wireline tool string. In case the cable such that in case the cable snaps, it is designed to fish in a easy way.

Figure 25 - Rope socket [7]

Stems

Stems are generally used to add weight to the tool string in order to overcome the pressure of the well. Weight also required for downward impact of jarring operations.

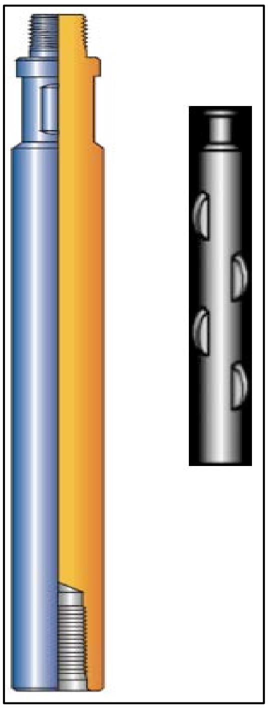

Figure 26 – Stems [7]

Jars

This tool is used to induce a mechanical shock to the tool string either upwards or downwards direction by extending and closing rapidly. The shock induced by the jar allows certain components such as plugs to lock into place and then unlock for retrieving. There are different types of jars used for different purposes. Spang /mechanical jars are manually operated by the wireline operator who either lifts or lowers wire rapidly, requiring a great deal of expertise. Power jars utilize springs or built-in hydraulics to give an upward jarring motion where greater force is required. Hydraulic jars deliver a stroke upwards.

Service Tools

Running tools

Plugs are set into nipples that are in the tubing by utilizing running tools. First, the plugs are fitted onto the running tool using shear pins made of brass or steel. Then, when the target nipple is reached the plug can be set by shearing these pins using jars.

Pulling tools

Pulling tools are utilized for fishing other wireline components that are dropped down in the hole. All wireline tools have 'fishing necks' on the topside of the tool, and these fishing necks enable and easy grab for the pulling tools. The pulling tools may also be used for retrieving installed components such as plugs.

Gauge cutter

This tool has a sharp metal ring in accurately determined size at the bottom end. The metal ring cut through contamination such as scale that has built up in the wellbore. Other uses of gauge cutters or gauge rings include determining the I.D. of the tubing, locating seating nipples or tight spots in the tubing. Gauge rings are generally run prior to running plugs and other tools to ensure that they will fit in the tubing.

Lead impression block

A lead impression block is run to determine the nature of an obstruction that is found downhole. The obstraction leave an impression on the malleable lead base of the lead impression block when they meet. It is also referred as wireline camera because of its function to mark any object downhole.

Bailer

This tool is designed to collect samples of downhole solids for the purposes of cleaning out or just determining the nature of solids such as scale. Dump bailers is used to transport acid and other chemicals down to specified locations in the well.

Go devil wire cutter

This tool can be used to cut the wireline when the wireline tool string becomes fouled. The tool is most applicable in conditions where the rope socket of the stuck string is clear of sand and debris.

Wireline finder

A wireline finder collects and balls up broken wire or cable down hole prior to running the wireline grab for retrieval.

Finder grab

A finder grab is used in the same way as the standard wireline grab in which is to retrieve broken wireline from the well bore. However, by using a skirt with the grab, the chances of passing the top of the broken wireline are reduced.

Well tractor

A well tractor has wheels on the sides and the wheels enable tools to be run and retrieved. The wireline operations may become very limited in deviated wells due to use of the gravity principal. As a rule of thumb a maximum deviation angle of 70 deg. have been considered to be the limit for the wireline method and wireline tractors are utilized in this area [22].

Figure 27 - Well tractor attached to various tools [7]

Different types of tools can be attached to the tractor to perform different types of operations [7].

- Manipulate sliding sleeves
- Handle gas lift valves
- Removing scale
- Brushing/cleaning profiles etc
- Collecting debris & sand
- Milling
- Logging 8. Perforations
- Setting/retrieving plugs etc.

Coiled Tubing Equipment

Coiled tubing equipment was presented in Figure 4. The equipment shown in the figure is explained as the following [22]:

Injector Head

Injector head is the driving force that pushes the tubing in and out of the well while supporting the weight of the tubing in the well. Hydraulic motors drive two opposed endless rotating chains of interlock drive blocks, press against the tubing by hydraulic cylinders and give a frictional grip. A hydro-pneumatic accumulator bank is used as backup for the hydraulic cylinders acting on the drive blocks. There is a load cell measuring the axial force in the tubing and the load is displayed in the control cabin.

Gooseneck

The gooseneck is a component mounted on top of the injector head to guide the coiled tubing from the tubing reel into the injector head.

Coiled Tubing Reel

The coiled tubing reel is composed of framework, reel, hydraulic motor, winding system, depth meter, swivel and a flushing system and the tubing is coiled onto the reel.

The function of the framework is to protect the reel and its components during transportation and operation. The hydraulic motor supplies the power to keep the tubing under constant tension while the tubing is coiled onto the reel. On the other hand, a torque brake keeps the tubing under constant tension and rotating momentum when the tubing is paid out. The winding system is made of a lead screw and a tubing guide arm. The tubing guide positions the tubing onto the reel and is synchronized to the rotation of the reel by a chain drive from the axle. The depth meter measures the length of tubing paid out. The swivel enables fluid to be pumped through the tubing while the reel is in motion and under any pressure. The flushing system prevents corroding of outside of the tubing by spraying oil based corrosion inhibitor when the tubing is winded onto the reel.

Well Control Equipment

The well control equipment is designed for the protection of people, equipment and the environment in an emergency situation. It can be subdivided into: BOP stack, shear/seal BOP and stripper.

The BOP stack has four ram valves. Blind ram seals against open bore, shear ram cuts the tubing, slip ram holds tubing and tubing ram seals around tubing. The ram valves can be operated both hydraulically and manually. Valves integrated in the body allow circulation and pressure equalization before opening.

The shear BOP is located just above the XT and its function is to seal the wellbore in an emergency situation. It may be both manually and hydraulically operated and it is controlled independently of the BOP stack. Also, an accumulator backup is connected to the circuit in the event of a power failure.

The stripper is located between the injector head and the BOP and enables the coiled tubing be stripped in and out of a live well. It consists of two sealing rubber elements, which are forced against the tubing by a piston. Also, a hydraulic circuit is integrated in the system to allow further pressure increase if necessary.

Power Pack

The power pack provides the hydraulic and pneumatic power to operate the intervention unit. If the temperature or pressure exceeds a preset level the engine is shut down automatically, as a safety precaution. A diesel engine is integrated into the power pack and drives the hydraulic pumps.

The hydraulic system in the power pack includes pumps, motor accumulators and a power supply to operate the well control system in addition to injector head and tubing reel.

Moreover, the power pack unit consists of an air system that supplies power to the brake control, reel unit, unit control system and safety system and a hose reel containing the umbilical for transportation of hydraulic fluids and air to the operating units.

A well tractor can be attached to the tubing as in wireline. It can’t be rotated from surface but it is possible to install a device like e.g. a motor on bottom that provides rotation.

APPENDIX B

Island Frontier, Island Wellserver and island Constructor has been designed as a light well intervention vessel and subsea support construction [11]. Below is the summary of some key properties of these three RLWI vessels.

MOU Island Frontier

Type:	RLWI - DP III
Design:	UT 737L
Yard:	Søviknes Verft AS
Year:	2004
Class	DNV+1A1, Ship-Shaped Well Intervention Unit-I, E0, DK(+), HL(2,8), DynPos AutR, HELD-SH, LFL*
L.O.A.:	106,2m
Width:	21,0m
DW:	4.700T
Deck area:	945m2
Accommodation:	72

MOU Island Wellserver

Type:	RLWI (Riserless Light Well Intervention Unit) - DP III
Design:	UT 767 CD
Yard:	Aker Yards Langsten
Year:	2008
Class:	DNV+1A1, Well Intervention Unit, E0, DK +, HL(2,8), DYNPOS - AUTRO, HELD-SH, LFL,COMFORT V(1) C(1), CLEAN DESIGN,NAUT AW,OPP-F.
L.O.A.:	116,0m
Width:	25,0m
DW:	8500T / 8.7m
Deck area:	1.150m2
Accommodation:	97 cabins (1 Man)

Island Constructor

Type:	RLWI (Riserless light well intervention unit) - DP III
Design:	Ulstein SX 121
Yard:	Ulstein Verft AS
Year:	2008
Class:	DNV + 1A1 with the following class notations: Well Intervention Unit, SF, E0, DYNPOS-AUTRO, NAUT-OSV (LOC), CLEAN DESIGN, OPP-F, CRANE, COMF-V(3), COMF-C(3), LFL, DK(+), HL(+), HELIDK.
L.O.A.:	120,2m
Width:	25,0m
DW:	8700T / 7,9m
Deck area:	1.470m2
Accommodation:	90 persons
Subsea crane:	150T
Moonpool:	8x8m
	Tower with guide wire winches
	Skidding system
	2xWork ROV w/heavy weather LARS

Skandi Aker

Skandi Aker is classed as a Well Intervention Unit in compliance with the IMO-MODU code [13]. It is specially designed and equipped for deep-water subsea well intervention operations. The unit's main features are subsea well clean-up and testing, pumping service, installation / Retrieval of XMT systems, subsea construction and installation, subsea maintenance, ROV operations/surveying, set up for shallow water riserless subsea intervention, wireline and coiled tubing subsea well intervention packages

Figure 28 shows the key specifications of Skandi Aker.

Design

STX OSCV06L

Main Particulars

Length overall:	156.9 m
Length between perpendiculars:	137.7 m
Breadth moulded:	27.0 m
Depth main deck:	12.0 m
Design draft midship:	6.5 m
Max. scantling draft midship:	8.5 m
Displacement:	22 820 m^3 @ 8.5 m draft
Gross tonnage:	16 000
Speed at draft 5.5 m approx.:	18 knots

Accommodation

Accommodation for 140 people plus hospital
2 single cabins - Captain class
2 single cabins - Client class
25 single cabins - Officer class
29 single cabins - Crew class
41 double cabins - Crew class

Classifications

IMO MODU
1A1 Ship-shaped Well Intervention Unit, E0, DYNPOS-AUTRO (IMO III), CRANE, HELDK-SH, CLEAN DESIGN with NAUT-AW, Comf-V(3) C(3), ICE C, SF, DK(+), HL(2.8)

Dynamic Positioning

DnV DYNPOS-AUTRO (IMO DP-Class III)

Maneuvering/Positioning

- Dynamic positioning system IMO DP-Class III
- Reference systems: 2 x Seapath, 2 x DGPS, 2 x HPR HiPaP 500, Fanbeam
- Thruster control system
- 4 x joystick panels on bridge

Power and Propulsion

6 x MAN main engines with a total capacity of 19 200 kW
6 x Siemens generators
1 x MTU engine with Stamford emergency generator
2 x tunnel thrusters - 1 900 kW
2 x retractable azimuth thrusters - 1 500 kW
2 x contra-rotating azimuth thrusters - 3 000 kW
1 x main propeller with high lift rudder - 4 000 kW

Capacities

Fuel oil:	2 300 m^3
Fresh water:	1 890 m^3 (FW production capacity 100 mt/d)
Water ballast:	8 900 m^3
Deck cargo:	above 3 500 mt
Cargo deck area:	2 210 m^2
Free deck area:	1 850 m^2 (excl. derrick and crane)
Deck load:	10 mt/m^2
Free deck width:	24.5 m
Free deck length:	65.0m

Lifesaving Equipment

4 x 70 POB lifeboats with capacity for 140 persons each side
1 x MOB Boat

Offshore / Subsea Cranes

- 400 mt AHC knuckle boom crane rated 3 000 msw:
  - o Harbour: 400 mt @ 15 m
  - o Subsea (1 000 m): 400 mt @ 13 m
  - o Subsea (2 500 m): 225 mt @ 13 m
- 50-100 mt AHC knuckle boom crane rated 2 000 msw

Deck Cranes:

Electro-hydraulic knuckle boom crane:	3 mt @ 15 m
Cargo rail crane:	7 mt @ 16 m (3 mt with gripping yoke)

Anti Heeling System

Two tanks each side
Two reversible propeller pumps, each of 1 800 m^3/h

Roll Damping System

Two off passive roll reduction tanks

Module Handling System

Module handling main deck:	60 mt
Module handling moonpool area:	100 mt

Well Intervention System

Module handling tower:	450 mt / 42 m height
o Lifting height:	34 m
o V-door height:	29 m
o Riser stands:	90 ft
Drawworks:	100 mt single fall / 450 mt 4 all - AHC
Riser tensioner system:	8 cyl. w/65 ft stroke & 725 mt total capacity
Upper tensioner system:	4 cyl. w/65 ft stroke & 120 mt total capacity
Moonpool:	450 mt / 7.2 m x 7.2 m
Riser/pipe handling:	Automatic Handling System
F&G ESD system:	ABB Safety System
Choke & kill manifold:	3 1/16" NB API 10 000 PSI
Drill water capacity:	1 000 m^3
Base oil/diesel capacity:	400 m^3
Brine capacity:	200 m^3
Fluid mixing system:	500 m^3
Riser system:	690 bar LRP and HP Riser
Mixing system:	3x100 m3, 2x50 m3, 2x25 m3 = 450 m3
Flareboom and deluge system:	Up to 20 000 bbls/day @ 50 psi

Pumps

3 x HP Well Serive Pumps:
- o 3 500 l / m @ 5 000 psi
- o Max working pressure 7 500 psi
- o 2 280 HP (1 700 kW) each

1 x HP Chemial Injection Pump:
- o 250 l / m @ 5 000 psi
- o Max working pressure 7 500 psi
- o 430 HP (320 kW)

ROV system

2 x Perry Slingsby Triton XLS 150 Work Class ROV systems
One centre moonpool and two sliding side ports with LARS

Moonpool

7.2 m x 7.2 m moon-pool

Helideck

For Sikorsky S-92

Figure 28 - Key specifications of Skandi Aker [13]

Modu Q4000

This vessel is specifically designed for well intervention and construction in depths of up to 3,048 m of water and constructed in 2002. In 2008, it refitted with a slimbore drilling capability and currently it operates under US flag [14]. The multi purpose vessel provides a stable platform for a wide variety of tasks, including subsea completion, decommissioning and coiled tubing deployment.

Key feature of the Q4000 are a multi purpose tower capable of fulfilling all traditional derrick roles, two cranes with lifting capacities of up to 360 Te and seabed access to 3,048 m, an 11.9 m x 6.4 m moonpool, a 7 **3/8**” intervention riser system, a 3,048 m heavy weather ROV system and an overall deck capacity of 4,000 Te.

Specifications of Q4000 are showed in Figure 29.

Classification
Class A+1 Column Stabilized Drilling Unit Classed by ABS as a MODU AMS, ACCU, DPS3

Accommodates
133 People

Dimensions	
Length	95.2 m (312 ft)
Beam	64 m (210 ft)
Operating draft	15.1 m (50 ft)

Operating Parameters	
Water depth	3,048 m (10,000 ft)

Deck	
Variable Deck Load	4,000 Te

Crainage	
Main crane	360 Te
Secondary crane	160 Te

Moonpool	
Weather deck	11.9 m x 6.4 m (39 ft x 22 ft)

ROV system
150 HP cursor deployed unit, suitable for heavy weather rated to 3,048 m (10,000 ft)

Dynamic Positioning (DP) System
Triple voting Alstom DPS 902 with 901 back up

Drilling Equipment and Well Operations Systems	
Derrick - Huisman multi-purpose tower Hook load 600 Te Free lifting height 44 m (144 ft)	
Rotary topdrive system	Hydralift HPS 650E rated to 7,500 psi
Travelling block	Huisman 6 sheave splittable block
Pipe handling	Hydralift horizontal pipe racking system with 22.7 Te knuckleboom crane
Motion Compensator:	600Te Passive and active Heave systems
Riser tensioners – 8 x 200 kip tensioners	
Well Service pumps - two Schlumberger MD 1000	
Intervention riser system (IRS) 7 ⅜”	
Mud Pumps	2 National HEX pumps 7500 psi 1000 gpm+
Mud Gas Separator	2000 gpm 22mm scf/day 85 psi working pressure
Liquid Mud Capacity	1190 bbls surface, 1800 bbls reserve, 16ppg fluid
Bulk Mud Capacity	4 x 42.5 m^3 (1500 cu ft)
Bulk Cement	2 x 42.5 m^3 (1500 cu ft)

Thrusters	
Installed Power	6 generator sets each 3,520 kW
Azimuthing Thrusters	4 aft and 2 fwd each 2,900 kW x 900 RPM
Fixed Thrusters	2 fwd each 900 kW

Figure 29 - Specifications of Q4000 [14]

Seawell

This vessel is registered and has been operating throughout the North Sea and Atlantic margin as a Light Well Intervention (LWI) vessel since 1987, performing subsea wireline and coiled tubing services [14]. The Seawell has entered more than 650 wells, decommissioned over 150 live and suspended wells and 15 subsea fields so far.

The Seawell is dynamically positioning class 2 (DP2) with key features of built derrick over a 7 m x 5 m moonpool and a travelling block rated to 80 Te capacity in passive mode. The vessel's derrick is equipped with guideline tensioners, a subsea wireline lubricator winch, riser handling capability and associated equipment. There are two main cranes, which provide a combined load capacity of 130 Te. An inbuilt well stimulation plant provides a full chemical treatment capability, including acid wash. The vessel is capable of flowing wells back to the surface for clean-up operations and can also be adapted to perform well stimulation tasks.

See Figure 30 for other specifications of the Seawell

Classification
DNV, Class + 1A1, Supply Vessel, SF, Well Stimulation, ICE-1B, EO, DYN POS, AUTR(ERN) DSV 2, DK+, Crane, Helideck, SBM

Accommodates
122 People

Dimensions	
Overall length	114 m (374 ft)
Breadth molded	22.5 m (74 ft)
Depth molded	11 m (36 ft)
Operating draft	6.4 m – 7.3 m (21 ft – 24 ft)
Displacement	11,935 Te
Gross tonnage	9,158 Te

Deck	
Deck Load	5 Te per m^2
Above main deck	900 m^2 (9,688 ft^2)
Below main deck	250 m^2 (2,691 ft^2)

Workover Derrick	
Lifting capacity	80 Te
Free lifting height	24 m (79 ft)
Active heave compensated	40 Te at 4 m stroke 70 Te at 2 m stroke
Subsea lubricator winch	40 Te

Cranage (main)	
Twin aft crane (twin mode)	130 Te
Individual aft cranes	65 Te
Max wire length	400 m (1312 ft)

Moonpool	
Working moonpool	7 m x 5 m (23 ft x 16 ft)

Well Stimulation
HP pumps 2 Dyer OPI 1,800 AWS Triplex
Mud / Frac liquid tanks 240 m^3 (1,500 BBL)

Diving System	
Depth rating	300 m (984 ft)
Divers in saturation	up to 18
Diving bells	2 x 6 m^3 (212 ft^3)

Thrusters	
Installed Power	6 generator sets each 2,110 kW
Azimuthing Thrusters	3 aft each 1,325 kW and 3 fwd each 2,200 kW

Vessel Speed
14 knots

Dynamic Positioning (DP) System
Kongsberg SPD 21
Kongsberg ADP 311 Back up system
Dynpos AUTR (DP2)

Figure 30 - Specifications of vessel Seawell [14]

Well Enhancer

This well is capable of performing perform a range of well testing procedures in addition to LWI operations [14]. The vessel has a 150 tonne multipurpose tower, capable of deploying wireline, slickline and coiled tubing tools besides kill pumps, an intervention lubricator control system and an active heave compensated main winch.

The Well Enhancer is ideally suited to a wide range of intervention and well management tasks including mechanical safety valve and SPM lock / change out, zonal isolation, perforation, pumping, production logging, well stimulation, subsea Xmas tree recovery / replacement and complete live and suspended well abandonment, including abrasive wellhead severance and recovery.

Key specifications of Well Enhancer are outlined in Figure 31.

Classification
DNV, Class + 1A1, SF EO, DYN POS, AUTRO, DSV-SAT, DK+, HELDK-SH, ERN 99, 99, 98

Accommodates
120 People

Dimensions	
Overall length	132 m (433 ft)
Breadth moulded	22 m (72 ft)
Depth moulded	11 m (36 ft)
Design draft	6.25 m (21 ft)
Displacement	12,000 Te
Gross tonnage	9,200 Te

Deck	
Deck Load	10 Te per m^2 (1 ton per ft^2)
Above main deck	1,100 m^2 (11,840 ft^2)
Below main deck	250 m^2 (2691 ft^2)

Intervention Tower	
Lifting capacity	150 Te
Active heave compensated	150 Te (nominal 100 Te)
Subsea lubricator winch	150 Te (nominal 100 Te)
4 guide line tensioners	
2 pod line tensioners	
Deployment capability of up to 3000m	

Cranage	
Main crane	100 Te
Operating depth	600 m (1969 ft)
2 x Auxiliary cranes	5 Te SWL

Moonpool	
Working moonpool	7.02 m x 7.32 m (23 ft x 24 ft)

Diving System	
Depth rating	300 m (984 ft)
Divers in saturation	up to 18
Diving bells	5.4 m^3 (191 ft^3)

Cement Unit
2 x SPM 600s

Propulsion and Power	
	4 generator sets each 3,000 kW
	2 generator sets each 1,500 kW
Forward propulsion	2 tunnel thrusters
	1 azimuth thruster (Retractable)
Aft propulsion	2 azimuth thrusters each 3,000 kW

Vessel Speed
13 knots

Dynamic Positioning (DP) System
Kongsberg KPOS DP21
Kongsberg KPOS DP11 Back up system
Dynpos Autro (DP3)

Figure 31 - Specifications of Well Enhancer [14]

APPENDIX C

Material Safety Data Sheet

Methanol

Version 1.02 ***Revision Date 14.09.2006***

1. Identification of the substance/preparation and of the company/undertaking

Trade name	***Methanol***
Synonyms	***Methanol, Wood alcohol, Methyl alcohol, Methyl hydroxide, Methylol, Monohydroxymethane, Wood naphtha, Wood spirit***
Use	*industrial use, Solvents, raw material for fuels or fuel additives, raw material for gas scrubbers*
Company	*Sasol Solvents* *A division of Sasol Chemical Industries* *Sturdee Avenue 2* *ZA 2196 Rosebank*
Information (Product safety)	***Telephone:*** *+27169604106* ***Fax:*** *+27169603573*
Emergency telephone number	*South Africa: 0800 11 28 90; International: +49 28 41 49 2408*

2. Composition/information on ingredients

methanol

content: *99.99 %W/W*

CAS-No. *67-56-1*	***Index-No.*** *603-001-00-X*	***EG-Nr.:*** *200-659-6*
Symbol(s) *F, T*	***R-phrase(s)*** *-R11 -R23/24/25 -R39/23/24/25*	

For the full text of the R phrases mentioned in this Section, see Section 16.

3. Hazards identification

Identification of the risks

R11	*Highly flammable.*
R23/24/25	*Toxic by inhalation, in contact with skin and if swallowed.*
R39/23/24/25	*Toxic: danger of very serious irreversible effects through inhalation, in contact with skin and if swallowed.*

4. First aid measures

General advice	*Immediate medical attention is required.*
Inhalation	*Move to fresh air in case of accidental inhalation of vapours. If breathing is irregular or stopped, administer artificial respiration. Call a physician immediately.*
Skin contact	*Wash off immediately with plenty of water for at least 15 minutes. Call a physician immediately.*
Eye contact	*Rinse immediately with plenty of water, also under the eyelids, for at least 15 minutes. Remove contact lenses. Call a physician immediately.*
Ingestion	*If swallowed, seek medical advice immediately and show this container or label. Do not induce vomiting without medical advice. Never give anything by mouth to an unconscious person.*

5. Fire-fighting measures

Suitable extinguishing media	*Water spray, Dry powder, Foam*
Specific hazards during fire fighting	*Flash back possible over considerable distance.*
Special protective equipment for fire-fighters	*Wear self-contained breathing apparatus and protective suit.*
Further information	*Cool containers / tanks with water spray.*

6. Accidental release measures

Personal precautions	*Keep people away from and upwind of spill/leak. Remove all sources of ignition. Do not breathe vapours or spray mist.*
Environmental precautions	*Should not be released into the environment. Prevent further leakage or spillage if safe to do so.*

Methods for cleaning up — Soak up with inert absorbent material and dispose of as hazardous waste.

7. Handling and storage

Handling

Safe handling advice — Provide sufficient air exchange and/or exhaust in work rooms. Wear personal protective equipment.

Advice on protection against fire and explosion — Keep away from heat and sources of ignition. Use explosion-proof equipment.

Storage

Requirements for storage areas and containers — Keep containers tightly closed in a dry, cool and well-ventilated place.

8. Exposure controls / personal protection

Components with workplace control parameters

NATIONAL OCCUPATIONAL EXPOSURE LIMITS

no data available

EUROPEAN OCCUPATIONAL EXPOSURE LIMITS

Components	Type	Control parameters	Update	Basis
METHANOL	TWA TWA	260 mg/m3 200 ppm	05 2003 05 2003	EU Exposure Limit Values EU Exposure Limit Values

Engineering measures

Provide sufficient air exchange and/or exhaust in work rooms.

Personal protective equipment

Respiratory protection — Respirator with combination filter for vapour/particulate (EN 141).

Hand protection — gloves suitable for permanent contact:
Material: butyl-rubber
Break through time: 8 h
Material thickness: 0.5 mm
unsuitable gloves
Material: leather, nitrile rubber/nitrile latex, Polyvinylchloride, natural rubber/natural latex

Eye protection	Safety glasses with side-shields
Skin and body protection	Protective suit, Safety shoes
Hygiene measures	Wash hands before breaks and immediately after handling the product.
Protective measures	Wear suitable protective equipment.

9. Physical and chemical properties

Form	liquid
state of matter	liquid
Colour	colourless
Odour	alcoholic pungent
pH	7; neutral
Melting point/range	-97.8 °C
Boiling point/range	64.7 °C
Flash point	12 °C; closed cup
Autoignition temperature	463.89 °C
Lower explosion limit	6 %(V)
Upper explosion limit	36.5 %(V)
Vapour pressure	97.68 hPa; 20 °C
Density	0.790 g/cm3; 20 °C
Water solubility	miscible
Partition coefficient (n-octanol/water)	log Pow: -0.8
Viscosity, dynamic	0.614 mPa.s
Relative vapour density	1.1

10. Stability and reactivity

Materials to avoid	Oxidizing agents, Reducing agents

11. Toxicological information

Acute oral toxicity	LD50 rat: 5,628 mg/kg;
Acute dermal toxicity	LD50 rabbit: 15,800 mg/kg;

12. Ecological information

Ecotoxicity effects

Toxicity to fish	LC50 Pimephales promelas: 29.4 mg/l; 96 h; literature value

13. Disposal considerations

Product	Dispose of as special waste in compliance with local and national regulations.
Contaminated packaging	Contaminated packaging should be emptied optimally and after being suitably cleaned returned for re-use., Store containers and offer for recycling of material when in accordance with the local regulations.

14. Transport information

ADR	UN-No.: 1230; Class: 3, (6.1); Packaging group: II; FT1; Description of the goods: METHANOL
RID	UN-No.: 1230; Class: 3, (6.1); Packaging group: II; FT1; Description of the goods: METHANOL
ADNR	UN-No.: 1230; Class: 3, (6.1); Packaging group: II; FT1; Description of the goods: METHANOL
IMDG	UN-No.: 1230; Class: 3, (6.1); EmS: F-E, S-D; MFAG: 19; Packaging group: II; Description of the goods: METHANOL
ICAO/IATA	UN-No. : 1230; Class: 3, (6.1); Packaging group: II; Description of the goods: Methanol

15. Regulatory information

Labelling

Regulatory base	67/548/EEC
Symbol(s)	F: Highly flammable T: Toxic
R-phrase(s)	R11: Highly flammable.

	R23/24/25: Toxic by inhalation, in contact with skin and if swallowed. *R39/23/24/25: Toxic: danger of very serious irreversible effects through inhalation, in contact with skin and if swallowed.*
S-phrase(s)	*S 1/2: Keep locked up and out of the reach of children.* *S 7: Keep container tightly closed.* *S16: Keep away from sources of ignition - No smoking.* *S36/37: Wear suitable protective clothing and gloves.* *S45: In case of accident or if you feel unwell, seek medical advice immediately (show the label where possible).*
Hazardous components which must be listed on the label	*methanol*

16. Other information

Full text of R-phrases referred to under sections 2 and 3

R11	*Highly flammable.*
R23/24/25	*Toxic by inhalation, in contact with skin and if swallowed.*
R39/23/24/25	*Toxic: danger of very serious irreversible effects through inhalation, in contact with skin and if swallowed.*

This MSDS summarises at the date of issue our best knowledge of the health, safety and environmental hazard information related to the product, and in particular how to safely handle, use, store and transport the product in the workplace. Since SASOL and its subsidiaries cannot anticipate or control conditions under which the product may be handled, used, stored or transported, each user must, prior to usage, review this MSDS in the context of how the user intends to handle, use, store or transport the product in the workplace and beyond, and communicate such information to all relevant parties.If clarification or further information is needed to ensure that an appropriate assessment can be made, the user should contact this company.

We shall not assume any liability for the accuracy or completeness of the information contained herein or any advice given unless there has been gross negligence on our part. In such event our liability shall be limited only to direct damages suffered. Our responsibility for product as sold is subject to our standard terms and conditions, a copy of which is sent to our customers and is also available upon request. All risk associated with the possession and application of the product passes on delivery.

The MSDS was created by:
The MSDS was approved by:

Reliance Industries Ltd.

Material Safety Data Sheet

Mono Ethylene Glycol

SECTION 1 - CHEMICAL PRODUCT AND COMPANY IDENTIFICATION

MSDS Name: MONO ETHYLENE GLYCOL (MEG)

Synonyms:

- 1-2-Ethanediol,
- 1-2-Dihydroxyethane

Company : Reliance Industries Limitged,
Maker Chamber IV,
222 - Nariman Point,
MUMBAI – 400 021 - INDIA
Tel. # 00-91-22 – 2842384 / 2826070

SECTION 2 - COMPOSITION, INFORMATION ON INGREDIENTS

Hazardous Ingredients	Approx. concentration %	C.A.S. or U.N. Numbers	LD-50 (specify species androute)	LC-50 (specify species and tests)
Fire, Human Toxic, Reactive NFPA Classifiction Health 1 Flammability 1 Reactivity 0	99.9 %	C.A.S .NO. 107 –21-1 U.N. NO. Not classified.	4 g/kg Rat /Oral	>100 ppm/48 hrs/shrimp / LC50 /saltwater

SECTION 3 - HAZARDS IDENTIFICATION / EMERGENCY OVERVIEW

Appearance : Colorless Liquid.

Potential Health Effects:

Eye : Causes eye irritation.
Skin : Causes slight skin irritation.
Ingestion : Causes systemic effects such as renal damage. It may cause effects similar to Alcoholic intoxication.
Inhalation : At elevated temperatures, MEG vapors may Cause respiratory tract irritation.

SECTION 4 - FIRST AID MEASURES

Eyes : Immediately flush eyes with plenty of water for at least 10 minutes. Get medical aid immediately.
Skin : Flush the contaminated skin with water for at least 10 minutes. Use Soap if available. Remove contaminated clothing and shoes. Get medical aid if irritation develops or persists. Wash clothing before reuse.

Ingestion : Do not induce Vomiting. Give Water (0.25 L /0.5 PINT) to drink. Get medical aid immediately.

Inhalation : Remove the affected person to fresh air. If rapid recovery does not occur, obtain medical attention.

Notes to Physician : Treat by observation and supportive measures as indicated by the Patient's condition. The essentials of therapy are

(1) Supportive treatment of respiratory distress and shock.
(2) Correction of metabolic acidosis and hypocalcemia.
(3) Rapid and sustained diuresis when possible with the use of hypertonic mannitol
(4) Immediate peritoneal or hemodialysis
(5) Thiamine and pyridoxine supplements
(6) Intravenous administration of ethanol if the diagnosis is recognized with in six hours after ingestion
(7) Treatment of renal failure with dialysis if needed to keep the patient free from the signs and symptoms of uremia.

SECTION 5 - FIRE FIGHTING MEASURES

General Information : Mono ethylene glycol is not classified as flammable but will burn.

Extinguishing Media : For small fire use dry chemical powder, Carbon dioxide, Alcohol resistant foam, Water fog, sand . For large fire use alcohol resistant foam or water fog.

Autoignition Temperature : 413.0 deg C)

SECTION 6 - ACCIDENTAL RELEASE MEASURES

General Information : Extinguish naked flame. Avoid contact with skin, eye and clothing. Use proper personal protective equipment as indicated in Section 8.

Spills/Leaks : Stop discharge if possible, isolate and Absorb the liquid with sand., earth or sawdust. Shovel up and remove all material to a safe place for subsequent disposal by burning or burying. Flush the contaminated area with plenty of water.

SECTION 7 - HANDLING and STORAGE

Handling : Handle with proper PPEs. Wash thoroughly after handling. Remove contaminated clothing and wash before reuse. avoid contact with eyes, skin, and clothing. Keep container tightly closed. Avoid ingestion and inhalation.

Storage **:** Normally stored at ambient temp under Inert atm. Store in a cool, dry, well-ventilated area

SECTION 8 - EXPOSURE CONTROLS, PERSONAL PROTECTION

Engineering Controls: Open through flame arrester (e.g. Ventilation, Enclosed process)

Personal Protective Equipment:

Eyes	:	Wear appropriate protective eyeglasses or chemical safety goggles
Skin	:	Wear Plastic / Rubber gloves to prevent skin exposure.
Clothing	:	Wear appropriate protective clothing to prevent skin exposure.
Respirators	:	Not Required.

SECTION 9 - PHYSICAL AND CHEMICAL PROPERTIES

Physical State	:	Liquid
Appearance	:	Colorless
Odor	:	Slight Sweet
Solubility	:	Completely Soluble in water.
Bulk Density	:	1.115 (g/ml)
Flash point	:	116^0C

SECTION 10 - STABILITY AND REACTIVITY

Chemical Stability	:	Stable under normal temperatures and pressures.
Conditions to Avoid	:	Incompatible materials like strong oxidants, heat , air and moisture
Incompatibilities with Other Materials	:	No.
Hazardous Decomposition Products	:	Nil

SECTION 11 - TOXICOLOGICAL INFORMATION

CAS#	:	107-21-1
LD50	:	4 g/kg.
LC50	:	> 100 ppm /48 hrs/shrimp/LC-50/saltwater

SECTION 13 - DISPOSAL CONSIDERATIONS

Treatment in effluent treatment plant or incineration after collection in drums or dykes etc.

SECTION 14 - TRANSPORT INFORMATION

Observe all national, state and local environmental regulations.

SECTION 15 - REGULATORY INFORMATION

Observe all national, state and local environmental regulations.

SECTION 16 - ADDITIONAL INFORMATION

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