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PREFACE

The main theme of this thesis work is to evaluate the possibility of achieving a safe and cost efficient P&A operation by the use of small intervention facilities (vessels). The synergy of the oil industry is toward IOR of subsea wells by reducing operational costs without affecting HSE related issues. The technology available today is scrutinized to see if the viable technical solutions will provide a successful P&A operation of subsea wells as performed normally by drilling rigs. Regulatory bodies have set stringent requirements for eternal abandonment of subsea oil wells, such that the sealing arrangement should be constructed to avoid oil seepage into ground water reserves and pollution of the environment.

ACKNOWLEDGEMENT

In particular, thanks to Mr. Harald Strand (Pre-rig Well Construction) of IOSS for providing the necessary information regarding P&A operations. Thanks also to Mr. Robert Friedberg (General Manager of IOSS) and Mr. Stein A. Tonning (PSA Discipline Leader/ Drilling and Well Technology)for giving their valuable time and acceptance to be interviewed.

My special gratitude and thanks to my supervisor Prof. Arnfinn Nergaard of the University of Stavanger for his contribution on subsea technical knowledge and expertise, establishing contacts and for taking valuable time in advising throughout my work.

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ABSTRACT

The main objective of this thesis is to evaluate challenges in satisfying rules and regulations set by regulatory bodies, constrains related to the well status as well as the limitation of technology available to perform plugging and abandonment activities. IOSS and NCA have joined resources in development of state of the art technology especially for full commercialization in P&A operations. It is required to provide suitable technical solutions to show to the authority that P&A for shut in well category 2&3 can normally be performed safely and successfully by fit for purpose intervention facilities as accomplished by drilling rigs. This will be a favorable solution for oil operating companies taking into consideration their determination toward IOR philosophy for subsea wells.

Safety authorities require a good quality of P&A operation that provides an eternal sealing arrangement to isolate reservoir fluids migration up to the sea surface. Therefore primary strategy was to establish a clear understanding of the state of a shut in well to be abandoned and the means to establish barriers to control well pressure prior to commencement of the P&A campaign as required by the authorities. A thorough study of guidelines related to selection and location of WBE is dealt with, especially the technology available for deployment of tools downhole when setting plugs. This forms the design bases for top side equipment capability needed for handling heavy lifts of subsea WCP packages, SLIS or riser system and BHA while performing P&A activities.

Based on evaluation of the state of the art of technology available today and exploration of the scope of work required to be accomplished on P&A operation for shut in well category 1 to 3, it is recommended that permanent abandonment by use of small intervention facilities be done since is as well economically a viable solution.

The major constrain in this work was the limitation in acquiring technical information for P&A operation since most of the information and experience available is not well shared in the industry and lack of supporting literature. It was necessary to gather technical information from experienced personnel who directly have been involved or performed P&A operations. This was a challenge and led into set back in the thesis work since most of the crew dealing with WOI operations was located offshore.

RESEARCH METHODOLOGY

Subsea development still is a developing arena; therefore there is insufficient supporting literature for P&A activities compared to offshore oil fields developed with platform based concept and onshore oil fields. This necessitated an approach of interviewing experienced people and seek of professional advice, therefore, some parts of this thesis is based on interview material.

In total there were 4 interviews conducted in Stavanger in the period of January to May 2009, each of length of minimum 1 hour. Three vis-à-vis interviews were with persons from Petroleum Safety Authority (PSA/Ptil), Island Offshore ASA, Nose Cutting and Abandonment (NCA) and one telephone interview was with Aker Solutions ASA. The issues discussed are enclosed in attachment 1, however, there were some modifications of them made while the interview was taking place in order to attain more thorough information. An example of 1 full interview answers is presented in attachment 2. The arguments attained from interviews gave a valuable contribution to the whole thesis and are not referred to particularly.

Important input was made also from the first supervisor Prof. Arnfinn Nergaard and the second supervisor related to the industry, Mr. Harald Strand.

Review of available literature was made: the sources were scientific papers, e.g. publications by SPE International, books, laws, regulations, lectures' notes in subjects Subsea Control, Marine Operations, Well Completion and Well Intervention, as well as material available on the internet.

During the process of the thesis work it was necessary to come up with diagrams which present simpler the processes involved in establishing the primary condition of well status and evaluating possible P&A procedures.

TABLE OF CONTENT

NOMENCLATURE

AoC – Acknowlogement of Compliance
AWS – Aker Well Solution
BHA – Bottom Hole Assembly
BOP-Blow-out Preventor
CT – Coile Tubing
CTF – Coile tubing frame
DNV- Det Norsk Veritas
DP class – Dynamic Positioning clas
DP Control-Dew Point Control
EDP – Emergency Disconnection Package
EQD – Emergency Quick Disconnection
ESD- Emergency Shut Down
GOM – Gulf of Mexico
GSF – Gimbal Support Frame
HC - Hydrocarbon
HMI – Human Machine Interface
HPU – Hydrauli Power Unit
HSE-Health Safety and Environment
HSLV – Higher Set Lubricator Valve
HXT –Horizontal ChristmasTree
IMCT – Internal Multi-string Cutting Tool
IMO-International Maritime Organization
IOM – Island Offshore Management
IOR-Improved Oil Recovery
IOSS – Island Offshore Sub Sea AS
ISO-International Standard Organization
IWOCS – Intervention Workover and Control System
LLP – Lower Lubricator Package
LMRP – Lower Marine Riser Package
LPIV – Lubricator Pre
LS –Lubricator Section
MGS – Mud Gas Separator
MHS – Module Handling System
MHT – Module Handling Tower
MPSV – Multi purpose Sevirce Vessel
NCA – Norse Cutting and Abandonment
NCS-Norwegian Continental Shelf
NMD – Norwegian Petroleum Directorate
NORSOK – Norske Sokkel Standard
OBM – Oil Based Mud
PCH – Pressire Control Head
PSA – Petroleum Safety Authority
RLWI – Riseless Well Intervention
ROT – Remote Operated Tool
ROV – Remote Operated Vehicle

SCSSV – Subsurface Controlled Subsea Safety Valve
SFT - Surface Flow Tree
SILS-Safety Integrity levels
TFL - Methods
TH – Tubing Hanger
THRT – Tubing Hanger Running Tool
TRT - Tree Running Toll
TTRD – Through Tubing Rotary Drilling
UKCS – UK Continental Shelf
UKOOA –UK Oil Operators Association
ULP – Upper Lubricator Package
ULP – Upper Lubricator Packahe
UPIV – Upper Pressure In
VXT – Vertical Christmas Tree
WBE – Well Barrier Element
WCP – Well Control Package
WH -Wellhead
WOI – Workover and Intervention
WOICS – Workover and Intervention Control System
XT-Christmas Tree

INTRODUCTION

The decommissioning phase of offshore subsea oil field involves Plugging and Abandonment (P&A) program, where casing strings are and conductors are cut and recovery of the wellhead system is achieved. Regulatory bodies requires that the cutting of casing strings should be attempted 5 m below seabed (mud line) and zonal isolation be placed at various depth to permanently seal off and mitigate influx of reservoir fluids to migrated in the wellbore to the surface. This may have catastrophic consequences to the environment by polluting the water aquifer as well as affect sea inhabitants.

Normally, operating company designs a P&A program based on the reservoir and wellbore data available and applies for consent to perform abandonment to the regulatory. Rules and regulations governs the wellbore abandonment where the primary responsibility is relies on the geographical location of the well. Further more considerations involving risks to future sealing capability failure should be made due to predicted build up of reservoir pressure (re-pressurization) and temperature (downhole changes) with time after abandonment.

The system for well categorization have been discussed since it is necessary to assess the primary conditions of the shut in well to be permanent abandoned. The issue of SCP has been addressed by examining the source and means of controlling bleed off and treatment of non reservoir or reservoir fluids trapped in annuli spaces.

It was necessary to account for state of the art of technology available today and evaluate cost and benefit related issues providing a safe and successful P&A program by utilizing a small intervention facilities contra drilling rig. This involved rules and regulation pertaining construction and use of small vessels for petroleum activities. The term small vessel is normally used in the oil industry frequently contradicting the fact that vessels are constructed with regard to flag state rules and regulations contra facilities governed by safety bodies regulating petroleum activities like NMD and PSA respectively. The term WI/RLWI VESSELs will be met in this project work implying small facilities built fit for purpose for light and medium well intervention activities.

1.0 ESTABLISH NORMAL STATUS OF SHUT IN WELLS

Well abandonment is a complex task that requires careful planning, risk evaluation and analysis with respect to safety issues and consent for abandonment program must be sought through to the legal authorities. The operators should adhere to the requirements and guidelines pertaining to the integrity of the well during plugging for permanent abandonment. The well status parameters are important to provide a framework for establishing satisfactory procedures for permanent abandonment where the objective is to permanently seal off and isolate the well forever. The principle parameters to achieve a successful sealing arrangement will depend mostly on data gathered from the completion of the well until the end of its producing life. In case of unsuccessful P&A, there are concerns to the environment liability and more critical is the cost risk for slick cleaning up and return for re-abandoning a leaky well. ***(11)***

1.1 CATEGORIZATION SYSTEM

In the North Sea, the UK sector, a categorisation system is developed to describe the status of suspended subsea shut in wells, particularly to exploration and appraisal wells. The system is described in paragraph 9 in the UKOOA (United Kingdom Offshore Operators Association) in which it is subjectively requiring a full review of the well with respect to risk assessment by taking into consideration the well status, proposed programme and ability to conform to legislation and operator's policy. The categorization system is as emphasised in Table 1. ***(3)***

Table 1. Commonly used categorization system.

Category	**Definition**
1	The well has been sufficiently suspended that final abandonment only requires removal of the wellhead.
2.1	The well has one annulus uncemented. Placement of an additional permanent barrier is required to complete the abandonment of the well. This may be done by placing a barrier into the annulus or placing a separate barrier. This type of a well may be abandoned with a drilling rig or a light well intervention vessel.
2.2	The well has two annuli uncemented. Placement of an additional permanent barrier is required to complete the abandonment of the well. This may be done by placing a barrier into the annuli or placing a separate barrier. This type of a well may be abandoned with a drilling rig or a light well intervention vessel.
3	The suspended condition of the well is not suitable for full abandonment without significant intervention. Typically with current technology, the abandonment programme will

	require a drilling rig to safely effect the operation.
4	Wells are placed in this category for several reasons: • The downhole status is not known, therefore can not be categorised • The well is in a condition where it is not possible to safely abandon with current technology

The wells categorization as seen on Table 1 is based on the level of intervention required in order to achieve final abandonment. Whereby, the simplest wells requiring only wellhead removal are designated Category 1. Wells which require shallow plugs set in the casing and adjacent annuli are in Category 2. Wells requiring deeper intervention e.g. to set supplementary reservoir plugs are designated Category 3 and all wells where the scope of work is complex and unclear due to uncertainties regarding suspension status are usually designated Category 4.

Further more the categorization can be defined with respect to the well accessibility, as follows:

Table 2. Suspended wells categorization as defined by accessibility.

Category	**Definition**
1	Accessible
2	Not accessible because:
2a	On a template with other wells that are developed or planned for development
2b	Less than 50m from other subsea infrastructure
2c	Within 500m safety zone of an installation or subsea development
2d	The well has an identifiable problem where the risk associated with abandonment requires additional study
2e	Is deeply buried under seabed

In the Norwegian sector, NCS , there is no special category of shut in wells, where the PSA/Ptil mostly refers to the Oil and Gas UK categorization system as described in table 1.

Normally, it is required that the guidelines are incorporated into the planning of all new wells by ensuring that they can be classed as Category 1 wells after suspension of production (plugged and SCP control undertaken by the rig). This is from the perspective of minimising future abandonment costs. It has been observed that a large percentage of the currently suspended wells population does not meet this Cat 1 criterion. Wells of Category 2 &3 pose a challenge to be P&A by small mobile facilities due to the necessary perforating and cementing requirements that need to satisfy regulatory bodies (i.e. UK Oil & Gas guidelines, PSA, MMS and others). The synergy that negate the need to mobilize a rig undertake these challenges and constrains which is the main focus and theme of this work.

1.2 WELL STATUS PARAMETERS

In the oil and gas industry a well may be shut in and permanently abandonment as it may become inactive due to diminished economic return (at end reservoir life) or when wells drilled for exploration and appraisal (E&A wells) are found not economically viable to produce. It is important to bear in mind that each well is unique and should be considered on an individual basis when considered for P&A permanently.

The key parameter to the long term integrity of abandonment principally depends on the soundness of the initial well design and effectiveness of the primary casing cementations. Successful cementation behind casings during well completion will provide a beneficial barrier during the life of the well though not regarded as primary barriers.

The UKOOA paragraph 4 and NORSOK Standard D-010 chapter 9.6 provide guidelines to what is required and considered to be the basic data/ information necessary to be gathered to establish the basis for well barrier design and abandonment programme:

a) Well configuration (original, intermediate and present) including depths and specification of permeable formations, casing strings, primary cement behind casing status, well bores, side-tracks, etc.
b) Stratigraphic sequence of each wellbore showing reservoir(s) and information about their current and future production potential, where reservoir fluids and pressures (initial, current and in an eternal perspective) are included.
c) Logs, data and information from primary cementing operations in the well.
d) Estimated formation fracture gradient.
e) Specific well conditions such as scale build up, casing wear, collapsed casing, fill, or similar issues.

It is recommended that uncertainties be taken into consideration during design of abandonment well barriers with respect to the following factors:

- Downhole placement techniques.
- Minimum volumes required to mix homogenous slurry.
- Surface volume control.
- Pump efficiency/ -parameters.
- Contamination of fluids.
- Shrinkage of cement or plugging material.

1.3 LOAD CASES AND RISK ASSESSMENT

During reservoir production, downhole condition changes such as pressure, thermal and total stress. These parameters will change drastically until the end of the reservoir production and the equilibrium at downhole condition will be reached several years after abandonment of the well. Thus necessitate taking into high consideration the estimation of pressure, thermal and stress changes that may develop in the reservoir after abandonment to prevent reduction of the plug sealing capacity due to plug failure as well as cement -rock de-bonding.

The concern of reservoir re-pressurization after abandonment is very likely due to an active aquifer located beneath the reservoir. The reservoir re-pressurization prognosis is presumed to be achieved in over 130 years of abandonment and the thermal recovery approximately takes 400 years**.** ***(9)***

In NORSOK Standard D-010 chapter 9.6.2, the load cases including functional and environmental loads are described as most unfavourable. Thereby for permanent abandonment the specific gravity of the well fluid accounted for design is required to be equal to the sea water gradient. Similarly the risk assessment relating to the time effect on well barriers is considered with respect to reservoir pressure development and deterioration of material due to sour fluids as well as sagging of weight materials in the well fluids.

1.4 LEAK POSSIBILITIES

In risk assessment it is important to estimate the possibility of a reservoir fluid leakage to the environment, to any location above the mud-line, which had to be done for each well configuration depending on its attributes. Identification of potential leak paths for each well should be inspected schematically with special emphasis for a leakage occurrence, in case one or more well barrier components should have failed by loosing the ability to contain the fluid within the well.

The leakage possibility depends on intrinsic attributes specifically related to the wellbore/reservoir fluid type (oil/gas), fluid severity (sour/non-sour) and wellbore/reservoir energy (flowing/non-flowing). The consequence of a leak may be a threat to personnel and environment and that is reflected by extrinsic attributes (surroundings of the wellbore) related to environmental location and sort of installation within the area. ***(12)***

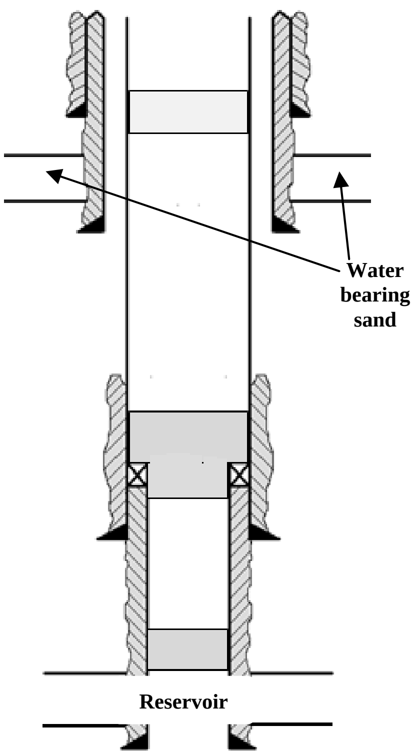

Figure1. Typical category 2.1 suspension (UKOOA).

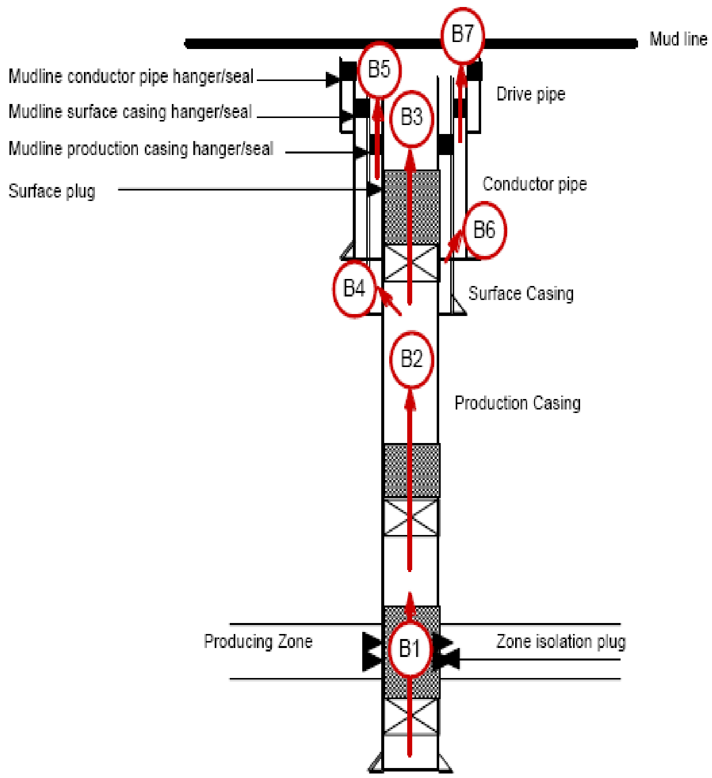

Figure2. Schematic well barrier leak paths PA well.

2.0 HANDLING POSSIBLY ENCOUNTERED TRAPPED HYDROCARBONS AND NON-RESERVOIR PRESSURE IN ANNULI SPACES.

The occurrence of sustained casing pressure (SCP) is divided into two categories, where the first is pressure occurring only on production casing as a result of mechanical problems with the tubing string or other operationally induced pressure, and the other category is related to SCP occurring on all outer casing strings including structural and drive pipes.

Primarily cementing between the casing strings provide support and prevent fluid movement through the annulus or into exposed permeable formations. During completion of the well, it is required that the cement slurry should effectively and efficiently displace drill cuttings and mud from the annulus and then solidify. The cement sheath formed should be able to withstand any future stress cycles that may be encountered during the whole life cycle of the well. Adequate design will influence a successful cementing job, that will include proper cement weight, composition, pre-job hole conditioning, and placement techniques. ***(18)***

2.1 SOURCE OF TRAPPED GAS AND HYDROCARBON LIQUIDS IN ANNULI SPACES

It has been recognized by the petroleum industry that three possible factors most likely may contribute to a loss in annular pressure seal. The possible causes of SCP are as follows:

i. Improper mud displacement previous to primary cementing
ii. Gas influx as the cement transitions to a solid
iii. Cement sheath stress cracking during the life of a well

These three factors in addition to early and late onset mechanisms of primary cementing job contribute in a great extent SCP development between casing strings. There could be a problem in achieving a successful primary cement job during completion or during the wellbore's productive life damages may arise due to excessive stress on the cement sheath leading to SCP and hence necessitate a costly remedial workover program.

The slow pressure buildup in annuli may be caused by a long term gas leakage mechanism due to fracture development as a result of cement shrinkage when the radial stress is less than the static porous pressure. The gas will gradually flow by diffusion due to increase in contact area between gas bearing formations and cement sheath as the fracture height continues to grow. Gas diffusion becomes continuous with decreased pressures at or near the surface due to gas leak off. ***(18)***

2.1.1 IMPROPER MUD DISPLACEMENT

Displacement efficiency is defined as the percentage of the annular volume filled with cement after pumping the cement slurry (Economides et al., 1998). Mud channeling must be avoided by all means during primary cementing job by proper mud displacement in the annulus. It is required to prevent mud channels or pockets that may cause pressure communication between zones or to the surface. It is necessary to take into consideration maintaining formation integrity when maximizing displacement efficiency. The mud displacement efficiency is influenced by the following factors as mostly agreed by (Mclean et al., 1967, Martin et al., 1978, Beirute and Flumerfelt, 1977, and Haut and Crook, 1979):

- Drilling mud conditioning
- Pipe movement and centralization
- Fluid velocity
- Spacer and flush designs (including density differences)

These factors all contribute to proper mud displacement and ultimately to the success or failure of a primary cement job. ***(18)***

2.1.2 Gas Migration through Unset Cement

API Cement slurries require different types of chemical additives to enhance or provide desired characteristics for a specific job. The cement additives available are grouped according to:

- Density control
- Setting time control
- Lost circulation
- Filtration control
- Viscosity control, and
- Special additives for unusual problems (Burgoyne et al., 1986).

The problem of annular gas migration through unset cement is well known and a great deal of work has been done to identify causes and to provide solutions for mitigation of gas influx.
During cement setting, gas can migrate through unset cement as it transits from fluid phase through the gel phase and hardens. Gas migration occurs when the overbalance pressure is lost due to the combined effects of static gel strength development and fluid loss (Carter and Slagle, 1972, Garcia and Clark, 1976 Levine et al., 1979 and Cooke et al., 1983). Gelation inhibits pressure transfer down through the setting column to make up for water volume reduction through permeable formations or from hydration. This is a point where gas can enter the setting cement and percolate to the surface leaving a permanent cement channel.

2.1.3 Cement Sheath Failure

The primary cement sheath must set and develop sufficient compressive strength as soon as it is once placed, seal annular flow and support the casing previous to continuation of drilling activities. Pressure tests during well completion work for integrity, excessive casing pressure and temperature changes during the life of the well may contribute to cement sheath failure and further lead to annular pressure built up. Radial stress cracks may develop due to casing expansion caused by internal casing pressure after the cement has obtained high compressive strength. ***(18)***

2.2 Safe methods for handling trapped gas and hydrocarbons under pressure in annuli spaces.

PSA requires safe entry of live well and well control action procedures should be available to deal with the incidents that may lead to liability. In NORSOK Standard D-10, paragraph 9.5.1 a table is provided to describe the scenarios requiring well control action procedures based on the planned activity. Paragraph 9.7 requires HSE risk assessment relating to cutting of tubular goods, detection and releasing of trapped pressure and recovery of materials with unknown status. Therefore a risk analysis shall be performed and risk reducing measures should be applied to reduce the risk as low as reasonable practicable. Refer to table 3 with regard to incidents requiring well control package.

Table3. Incident scenarios requiring well control actions.

Item	Description	Comments
1.	Cutting of casing.	Trapped gas pressure in casing annulus.
2.	(SSW) Pulling casing hanger seal assembly.	Trapped gas pressure in casing annulus.
3.	Re-entry of suspended or temporary abandoned wells.	Account for trapped pressure under plugs due to possible failure of suspension plugs.

Bleed off options available for SCP are conventional bleed off system normal developed and applied in drilling rigs and the alternative bleed off system developed for containment and handling of SCP for small mobile facilities (WI-VESSEL). The following subchapters give detailed information and description of bleed off systems explanation as well as bleeding process of non-reservoir/reservoir contained casing pressure.

2.2.1 CONVENTIONAL/ NORMAL SCP BLEED OFF SYSTEM APPLIED ON DRILLING RIGS.

2.2.1.1 SCP DETECTION

The first noticeable indication of SCP is a kick entering the wellbore after perforation of the casing string, which leads to the return of casing completion fluid with an initial peak pressure to the surface. The flow rate is readily noticeable at the surface under normal P&A conditions of a shut in well. Eventually pressure decrease in the annulus is readily noticeable due to the loss of hydrostatic pressure in the annulus as the gas volume enters the wellbore (wellbore pressure increases). Over time, hydrostatic effects tend to dominate the whole system, and BHP increases significantly.

The alternatives considered for stopping non-reservoir/reservoir fluid flow from the well is by closing a subsea blowout preventer (BOP) as in conventional well-control operations after the peak pressure is detected. When the BOP in figure 3 is closed, BHP starts to increase and the SCP from annulus flow decreases. It is important to know the allowed kick margin (total kick volume) not to exceed the riser burst strength for safety. The risk of exceeding the fracture pressure at the casing shoe is a relevant issue in any well-control situation, especially important for the narrow margins between pore and fracture pressure.

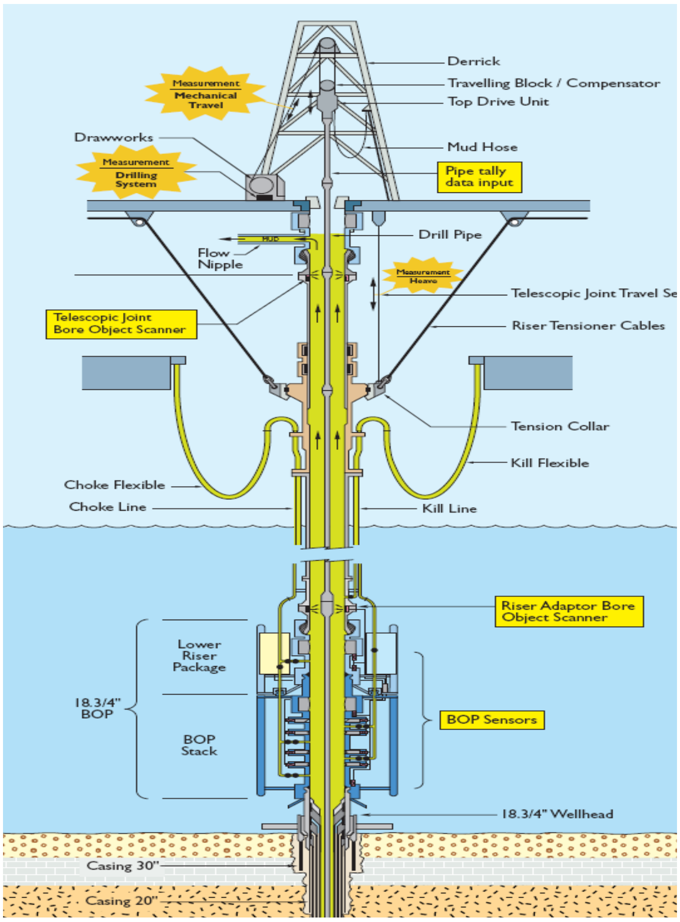

Figure 3. Drilling rig system

2.2.1.2 CSP CIRCULATION

2.2.1.2.1 The diverter system.

SCP can be controlled by a diverter which is hydraulically opened by high pressure migrating up the riser system. The diverter serves as dual purpose well control unit: It acts as a diverter while the upper hole is being drilled with a riser system in place as well as a annular blowout preventer after the conductor pipe has been cemented. During P&A operation the unit divertes SCP flow from the well by rerouting below drill floor through vent lines far from the rig. With the integral valve design, the piston movement hydraulically/pneumatically closes the upward flow path and opens the vent line for well fluid. For simplicity its single control eliminates the need for external valves, actuators and interconnecting control circuits. Below is the description of the FSP diverter features where simplicity enhances safety (see figure 4):

- A vent line that is always open and clear. There are no valves to obstruct the vent line.
- Elimination of stagnant vent line space. As a result, there is no caking of solids or formation of ice that could obstruct or shut off the flow.
- An annular packing unit that closes on an open hole without use of an insert cartridge that can be overlooked or installed improperly. The packing unit also closes around drill pipe, kelly, casing and most tools.
- Stripping capability. The FSP annular packing unit permits stripping of pipe into the hole while diverting well fluids.
- A replaceable wear plate that eliminates metal-to-metal contact between the packing unit inserts and the BOP head.
- A bolted-in inner sleeve that eliminates the need for weld repair and is field-replaceable. ***(19)***

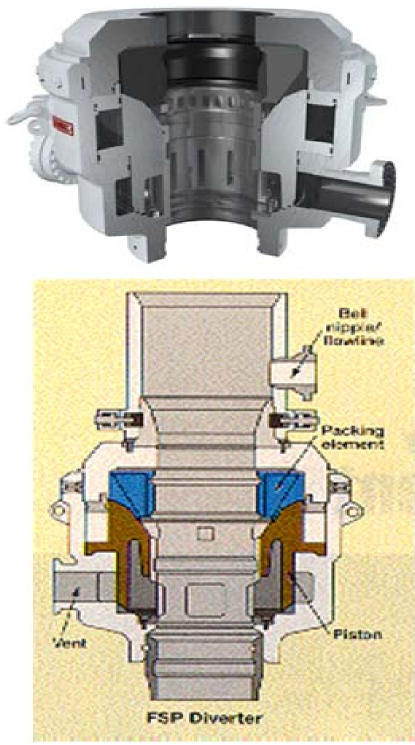

Figure 4. Hydril diverter system (The FSP™ 28-2000 (Flow Safe

After the SCP has been detected and the volume flow can not be controlled by a diverter system, the BOP subsea may be closed by shutting in the well and bleed off SCP be controlled in the similar manner as a well kick through choke and kill lines. The circulation of the completion fluid from the annuli with non-reservoir/ reservoir gas under high pressure will be lead through the choke lines from the BOP to the choke manifold and the pressure controlled through choke valves. The completion fluid/mud gas mixture will flow downstream to a mud/gas separator or de-gasser and gas bleed off and flared through a flaring system. Next page is the system description of the choke and kill line used on the conventional mobile drilling facility used to control a well kick.

2.2.1.2.2 The kill and choke circuits

i) The kill line

The system working pressure, pump liner size, maximum pump rate and pressure are clearly rated to the BOP pressure requirement. In any situation where the expected worst case kick conditions could not be handled, a high pressure kill line will be used. This arrangement is always on floating vessels and allows the well to be killed either by pumping under BOP's through a non return valve or down the drill string through a circulating head.

ii) The choke circuit

All the equipments down stream of the chokes are rated at low pressure in contrast to upstream of the chokes which must have a working pressure rate at least equal to that of BOP stack.

iii) Choke lines

Choke lines are connected to the drilling spool in the BOP stack as seen in figure 5 by means of two valves in series where one of the valves **is** remote controlled so that the choke line can be opened rapidly in an emergency. It is required that two high pressure lines are fitted on floating vessels which can each act as a choke or kill line.

The choke lines should be free of sharp bends and the use of small diameter choke lines is avoided since would consequently lead into high fluid velocities, significant erosion of the pipework and excessive pressure loss especially during the expansion of slugs of gas. Therefore it is very important that the diameter of the choke line should be as large as possible (3" or more).

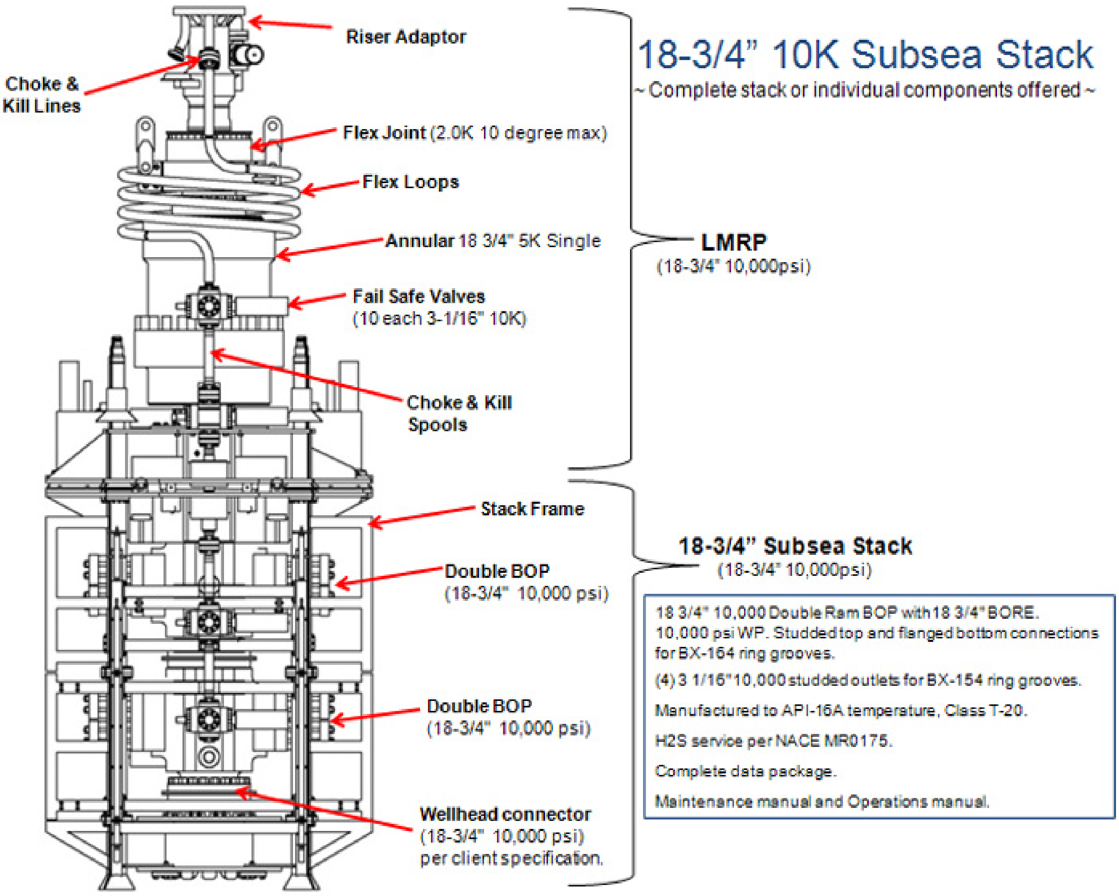

Figure 5. BOP choke and kill lines *(21)*

iv) Choke manifold

The choke manifold is a series of lines, automatic valves, gauges, and chokes on the located on deck next to the drilling rig. It is connected to the BOP stack outlet by a choke line and direct flow from the well to the reserve pit, burning pit, mud tank. It can be used to relieve pressure buildup in a well after the BOP stack has been closed and to circulate heavier drilling mud. The choke manifold must be easily accessible.
At least two adjustable chokes are fitted in the manifold to avoid the possibility that the choke system may be plugged and interrupt the controlled circulation after a kick. It is recommended that three adjustable chokes be fitted for manifolds with a working pressure greater than 5000 psi (two manually controlled and one remotely controlled). Outlets with lower working pressure are provided downstream the chokes manifold to the de-gasser, flare, slush pit and mud tanks.
A pressure gauge normally covering a pressure range up to the BOP working pressure and recorder are permanently installed on the manifold upstream of the chokes, to give a continuous reading of the surface pressure in the drill pipe/casing annulus. It is advisable to add a carefully calibrated low-pressure gauge (50-100 bar depending on P_{in}) in order to avoid breaking down the formation when the well is closed in after a kick. A pressure gauge showing the drill pipe pressure should be located so that it can be read when standing at the choke manifold. These two pressures (drill pipe and annulus) should also be displayed at the remote control station ***(2)***.

2.2.1.2.3 The low pressure circuit

i) De-gasser.

The most commonly used type of de-gasser is the vertical separator with interior baffles. There is often a second de-gasser, downstream of this separator, which works in a closed circuit on the first active mud tank. The gas removed from the mud must be discharged outside the security zone or classified area ***(2)***.

ii) Flare system

Two flare lines are normally installed with horizontal flare booms and they are located as far as possible from the classified areas.

iii) Mud tanks.

The volume of the mud tanks must be sufficient to cope with the requirements of kick control (weighting the mud, squeezing, etc.). If possible the capacity of the tanks should be at least equal to the volume of the well when reservoir or other danger zones are penetrated.

iv) Mud mixing equipment.

A bulk mud mixing device should be installed capable of mixing 6 t/hr of weighting material ***(2)***.

2.2.2 Alternative technology applied on WI VESSEL handling SCP.

A controlled pressure relief system (CPRS) for handling SCP has been developed by IOSS for P&A operations, where the bleeding off SCP is controlled by means of a choke manifold system on deck of a mobile facility. The requirements for the system include safe separation of gas from liquid and the relief/venting of the gas at a safe exit point as illustrated in figure 6. The CPRS shall as well have a minimum capability of handling 1.5 times the trapped volume of non-reservoir/reservoir pressure in subsea well control package (SSLIS) from the well *(Typical volumes of 850-900litres = Total capacity requirements +/- 900*1.5=1350litres).* ***(15)***

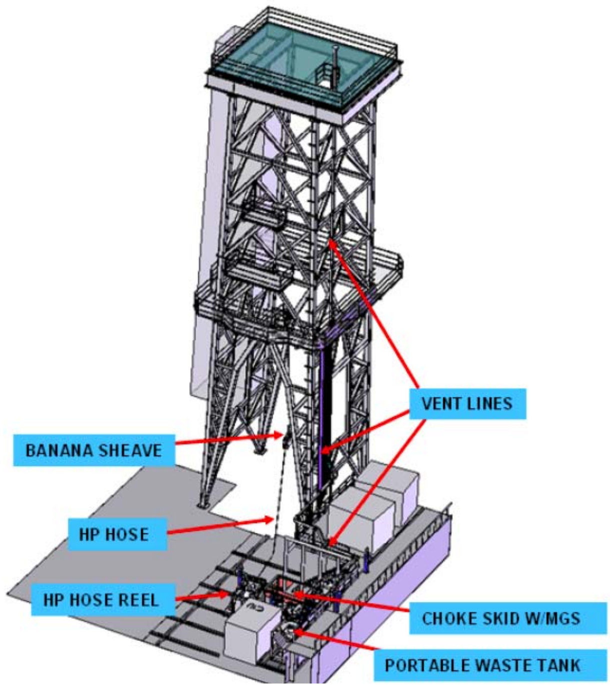

Figure 6. MHT and vent lines for SCP

2.2.2.1 Description of the overall bleed off system

The design of the CPRS comprises of the following equipments:

i) Choke manifold

- A *simplified* manifold system available to route returns from the umbilical to the choke and ventilation system. A minimum 690 bar working pressure is a requirement for lines and hoses between the umbilical and the choke manifold system, connections and valves on the high pressure side of the choke manifold.
- A minimum 2 valves should be mounted in series in front of each choke.
- The choke manifold shall as a minimum include 2 (two) chokes, a manual and automatic remote operated (auto choke).
- In the case of manually operated chokes, the circulating pressure and the choke manifold pressure shall be displayed on or close to the manifold. All pressure indication gauges should be through hydraulic pressure de-boosters with remote output.

The routing of the system vent-lines from the choke manifold is fitted up the top of the derrick structure, as seen on the picture above. The routine of the vent-lines from K&C lines is similar to that commonly used on drill rigs ***(15)***.

ii) Control system

The auto operation is controlled via a touch screen LCP or from central control room via a data link. All measured process data are available on the LCP and data link. Manual operation is done directly on the manual choke and local instruments for pressure and temperature inside the manifold and flow in the vent line are located close to the manual choke.

iii) Separation system (Mud Gas Separator)

The mud gas separator (MGS) is a system provided to separate gas from liquid where it is located adjacent to the choke manifold. The system is designed and equipped with standard internal baffle system for flow separation of mud-gas mixture. The separated gas outlet is routed through the vent tower over sufficient height. The fluid outlet from MGS is via a pump sump that utilizes a liquid seal to prevent gas entering a transfer pump which loads the separated fluid into a portable tank. The pressure differential in the pump sump between the gas and fluid is used to control the outlet valve keeping liquid seal in the MGS constant ***(15***.

iv) Waste handling

The waste is handled by a positive displacement pump (lobe pump) which is controlled by the level in the pump sump transferring the fluid to the portable tank. The pump sump is suitably built such that it acts as a buffer for high flow of fluid during bleeding off gas and fluid. The vent lines from the portable tank and pump sump are connected separately on the choke manifold system by quick connections and flexible hoses.

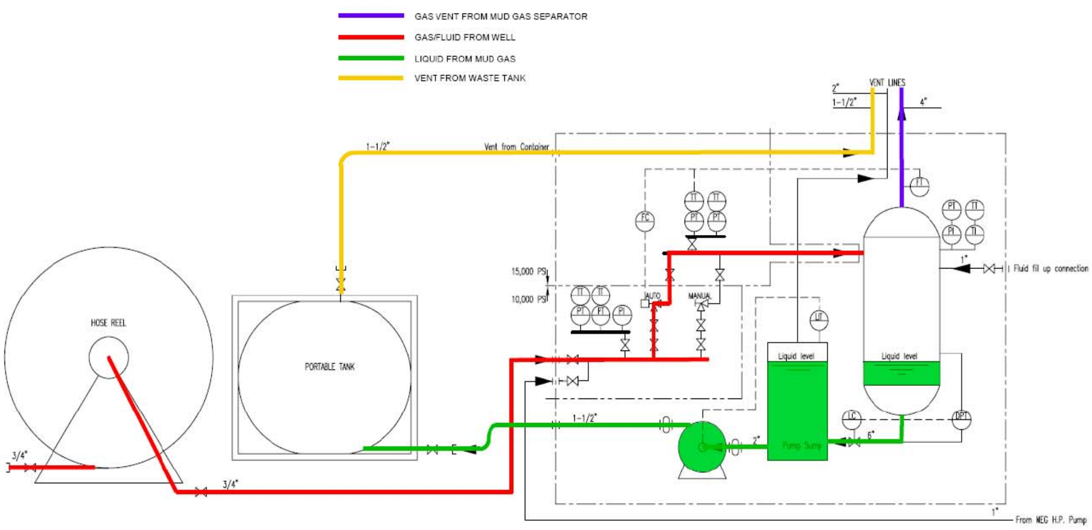

Figure 7. Presentation of the main flows through the MGS system P&ID.

v) Hose reel

The hose reel station on the diagram, connects the choke system to the wellhead with a high pressure hose and the station is hydraulically operated by the facility HPU. The hose is provided with an isolation valve enabling storage of the hose fully pressurised and a quick connection for ROV operation. The hose reel directs the gas and fluid to the MGS through the choke system ***(15)***.

3.0 ESTABLISH OVERALL PROCEDURE FOR ENTIRE OPERATION SEEN FROM THE WELL ASPECT.

Government bodies, like PSA in Norway, provide guidelines and regulate wellbore P&A with primary responsibility depending on the location of the well. Regulatory guidelines govern the P&A operational procedures where former producing horizons are plugged and casing is cut off below the mudline, requirement of at least two, and mostly often three, zone isolating plugs. Lastly, thorough procedures and verification for testing set plugs are outlined according to guidelines ***(4, chapter 4.7.2 and chapter 9)***

3.1 PLANNING AND REGULATORY CONSENT FOR P&A PROGRAMME FOR SUBSEA WELLS.

In the federal Outer Continental Shelf (OCS) in the Gulf of Mexico (GOM), the Minerals Management Service (MMS) is the lead agency that provides regulations, guidelines and general applications to all wells and specifies the minimum requirements to P&A. The operator is required to submit form MMS-124, 'Application for Permit to Modify (APM)', and receive approval for the operation. Form MMS-124 contains information on the reason the well is being plugged, a work requirements description, an assessment of the expected environmental impacts of the operation, and the procedures and mitigation measures necessary to minimise such impacts (Federal Register, 2002). It requires that before operations **commences**, the MMS District Supervisor should be notified at least 48 **hr** prior to the operation.

In the NCS, the Petroleum Act Re Section 22 on Decommissioning plan states that: *The Norwegian Pollution Control Authority shall be notified of decommissioning of petroleum activities, cf. the pollution Act Section 20. If the decommissioning plan in accordance with the Petroleum Act is not sufficient in relation to requirements given in or pursuant to the pollution Act, the Pollution Control Authority may demand further information and investigations to be performed to map the risk of pollution in connection with and after decommissioning of petroleum activities, cf. the pollution Act Sections 49 and 51. In addition, the Pollution Control Authority may stipulate what measures are necessary to counteract pollution, cf. the pollution Act Section 20 second paragraph.*

Guidelines Interpretations on Section 22 Decommissioning plan states that:
The plan that the licensee is required to prepare according to the Petroleum Act Section 5-1 shall be submitted to the Ministry of Petroleum and Energy and the Ministry of Labour and Social Inclusion with a copy to the Norwegian Petroleum Directorate and the Petroleum Safety Authority. In addition to documentation as mentioned in Regulations 27 June 1997 No.653 to Act relating to petroleum activities Section 44, the plan shall contain a description of the following:

- *a) risk during and following a possible removal,*
- *b) methods intended to be used in the event of a possible removal, including refloating of the structure,*
- *c) analyses planned to be carried out,*
- *d) operations planned to be carried out in the event of a possible removal,*
- *e) consequences of a possible removal in respect of adjacent fields and facilities,*
- *f) other matters of importance to a prudent conduct,*
- *g) measures, if any, designed to secure the area against possible future pollution from abandoned wells and/or polluted deposits of cuttings.*

The P&A plan of the well should entail the procedure based on the reservoir and wellbore condition including a review of the existing wellbore design along with records of past intervention work, well performance and geologic conditions, age of the well that influences hardware deterioration. Further the operator shall investigate all items related to health and safety issues by taking into consideration regulatory requirements. The operator will design a P&A programme for a specific well and will apply for regulatory approval. The P&A operation of a well shall as well include the contract type, site location, job specification, water depth and the occurrence of exogenous events, such as weather and problem wells. Factors such as wellbore complexity, job preparation and contractor experience are unobservable and may influence the time and cost of the operation. The operator must include in a comprehensive plan contingency responses to difficulties that may be encountered during the operation ***(22)***.

3.2 PLUG SETTING

A plan for plug setting and conditions at the time of the activity will determine the success of the operation. As previously discussed, it is necessary to consider each well differently since each well is unique due to the basic data available. The number of barriers for isolation of distinct permeable zones and from surface or seabed should be as described in the UKOOA guideline requirements in paragraph 3. The guidelines provide required standards for abandonment as discussed in detail in paragraph 5 taking into consideration §5.1 acceptable permanent barriers material and §5.2 location from surface. NORSOK Standard D-010 paragraph 9 requires that there should be at least one well barrier between surface and a potential source of inflow, and two well barriers unless it is a reservoir (contains HC and/ or has a flow potential) as seen on attachment 3 (NORSOK Standard §9).

Preferably it would be of great advantage to discuss the plugging procedures with respect to well categorization. The objective and limitation of this thesis will basically focus in P&A of subsea shut in wells Categories 1 to 3.

Each case of well P&A category is handled separately taking into consideration the status of the well. Three thorough flow diagrams have been developed to establish complex issues to be accounted for before conducting P&A process. The guidelines and flexibility in the application of regulations set by regulatory authorities defers in the Gulf of Mexico (GOM), North Sea UK side and Norway. The guidelines provided in the NORSOK Standard D-010r3 are generally used for P&A in the NCS. PSA is responsible for supervision of the decommissioning activities and recommend the application of the UK Oil and Gas guidelines (UKOOA) for P&A as well as ensure that the well permanent seal integrity is assessed to prevent pollution after abandonment. In NORSOK Standard D-010r3, the minimum requirements for permanent barriers are not specified in contrast to the UKOOA guidelines where the locations and height of cement plugs (barriers) are specified (paragraph 5 Required Standards for Abandonment section 5.1-3). The guidelines in NORSOK D-010, paragraph 9 recommend that the minimum position of the well barrier be designed for integrity such that the secondary barrier shall be placed at a depth where the estimated formation fracture pressure exceeds the contained pressure below the well barrier. In the GOM, well plugging procedures usually require a minimum of three cement plugs, though the exact number of plugs varies with the downhole conditions of the wellbore and the number of production zones. It is as well required that the cement quality must meet the approval of the MMS District Supervisor. Most cement plugs are 100 - 200ft (30 - 60m) in length to provide a seal against the vertical migration of fluid or gas.

It is required that all portions of the well that are not plugged with cement should be filled with fluid to control the possible influx of formation fluids into the wellbore in the intervals between plugs. It is necessary that the fluid should have the proper density to exert hydrostatic pressure exceeding formation pressure in the intervals between plugs during abandonment. The use of reconditioned drilling mud or completion fluid is allowed and most cases the fluid can be mixed on-site ***(22)***.

3.3 Factors to be considered when planning a safety efficient P&A program for subsea Wells.

Prior to establishing a P&A program, it is necessary to outline factors to be prevailed over for a successful permanent abandonment of the well especially considering that the process will be performed by a small mobile intervention facility. The conventional P&A operations by the use of drilling rigs are well known and technically proven to be very successful despite of the underlying high costs of rig charges. The new approach of conducting P&A operation by a small facility with the main focus in cost reduction (cost efficient) without jeopardizing the environment and safety, will require a very thorough planning and careful consideration of all aspects of constrains that may have an impact in HSE issues.

Principally, the well status determines the scope of work to be done and the technicalities required to permanently achieve a successful abandonment of the well. The small internal diameter of well control package applicable for light & medium well intervention governs deployment methods and size of toolstring (length and diameter).The technology available to a new approach in well P&A necessitate treatment of each well category individually. Flow diagrams have been developed as seen in figure 8 highlighting the complexity of P&A operation for each category and stepwise technical approaches of achieving well bore isolation.

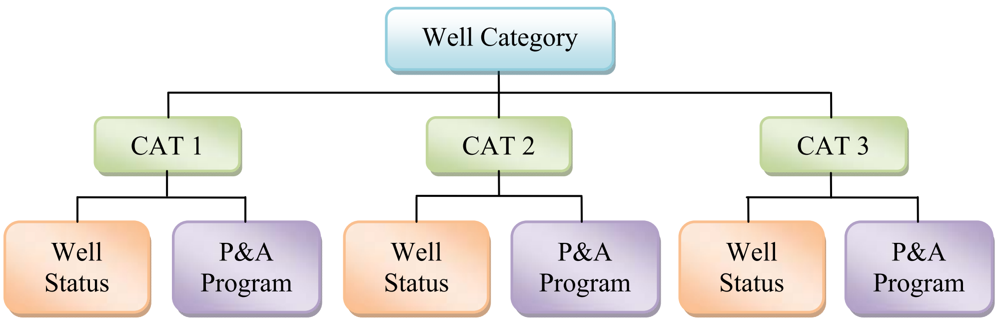

Figure 8. Hierarchy approach of highlighting shut in well state and P&A procedures.

3.3.1 P&A program for shut in well Category 1: Rig Chase (WH Pick; 30”+20”)

Regulatory bodies require operators to prepare wells not economicaly viable to produce at end of producing life to a level of Category 1, where the preliminary abandonment procedures have been completed by the drilling rig (recovered production tubing, plugs set, perforated casings and bleed off SCP/ reservoir fluids under pressure that may be found between casing strings/annuli spaces).

The P&A program will only require WH recovery where today it is done by a MPSV, severance of casing strings performed by utilizing water jet cutting (IMCT) and lifting of the WH by a WH Pick up tool (Norse Cutting & Abandonment- NCA). According to the interview with Mr. Per Lund of NCA conducted on 6th March 2009 at 1300hrs, the procedure of wellhead cutting (Rig Chase Method), seen in figure 9, is performed without the use of risers since the well has been secured by plugs and any traces of SCP in the casings annuli spaces have been bled off by a drilling rig. Rig Chase Method means releasing (chasing) the rig to move to a new location while DP MSV conducts the WH removal campaign saving *60% of abandonment costs* and *three to six hours of rig spread time* useful for drilling activities. The rig chase method has superior cutting speed ranging from 1-2hrs and the 6 -10 hrs deployment roundtrip deck-subsea-deck.

Other reasons of securing a shut in well in category 1 state:

- Temporary abandoned well with the possibility of re-entry and later the decision is made by the operator to permanently isolate and abandon the well.
- Slim well with no possibility of deploying cutting tools for severing the casing strings. Obviously slim wells have small dimensions on downhole equipments requiring the use of wire line deployed tool.

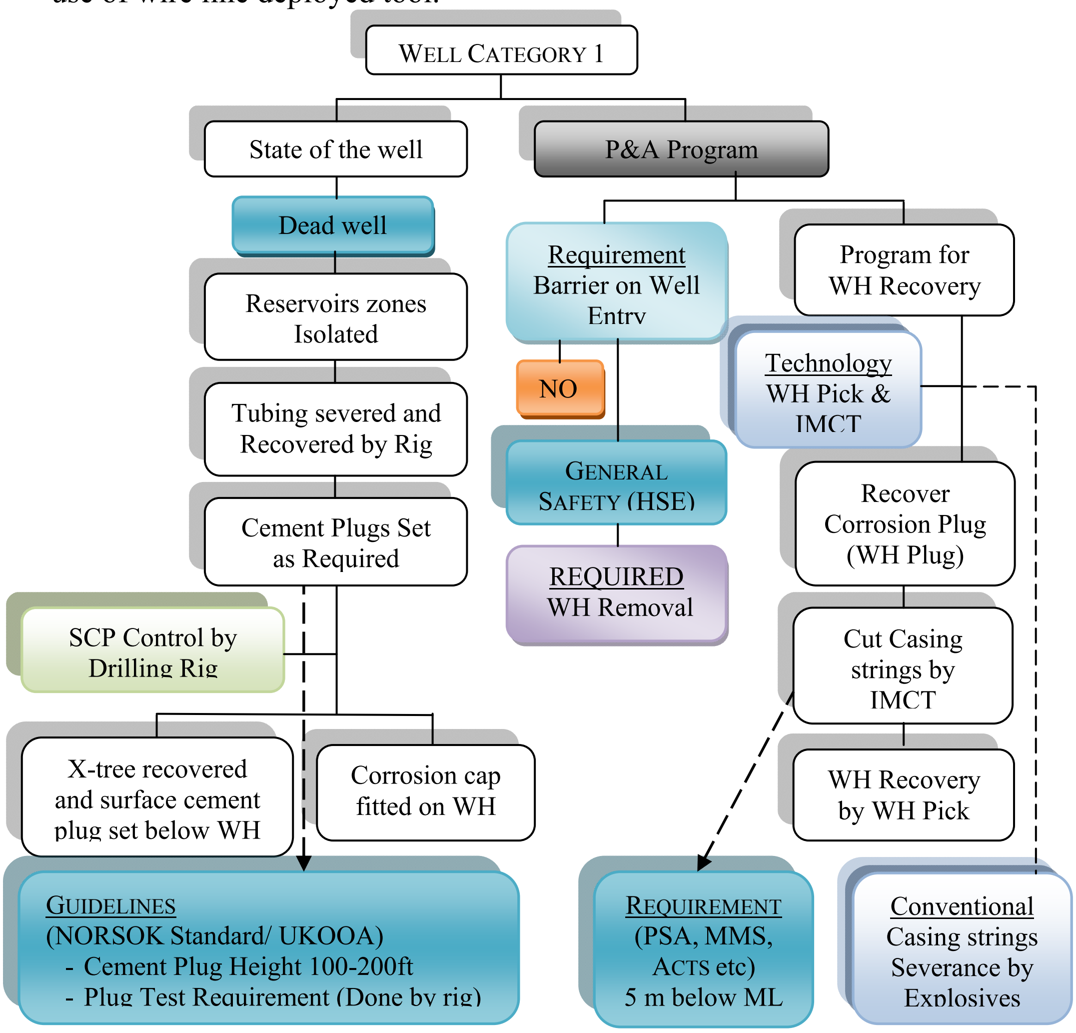

Figure 9. Category 1 well status and WH recovery procedures.

3.3.1.1 THE RIG CHASE METHOD IS CONDUCTED AS FOLLOWS (NCA):

1. Rig up on deck the Subsea Wellhead Picker (WHP) equipped with an Internal Multi-string Cutting Tool (IMCT).
2. Deploy the WHP with heave compensated crane over the side of a vessel or run through moon pool of the vessel by a module-handling tower.
3. The IMCT is stabbed (ROV assisted) into the inner casing and lowered to cutting depth typically 15ft (5M) below mudline as required PSA/Ptil. Thereafter the WHP connector is lowered and latched onto the Wellhead.
4. Conduct a pull test to verify integrity.
5. Perform multi-string cutting by severing all the layers by abrasive water jet cutting in one attempt.
6. Recover wellhead and conductor once cutting is completed.

3.3.1.2 SYSTEM DESCRIPTION AND OPERATION

The IMCT is equipped with packers, air supply, and return lines, where once the packers are set and engaged, then pressured air displaces water below the cut line. The atmosphere created is coupled with the abrasive slurry system which contributes to severing of the multi-string. The heave compensation system will determine the operation window such that it can be carried out with a significant wave height, Hs ≤ 3m. *(Offshore magazine - World Trends and Technology for Offshore Oil and Gas Operations/* ***(10)*.**

Most WH recovery activities by the use of DP MSV are conducted in the North Sea, UK offshore side, with long offshore history and old fields. This method of WH recovery is not fully commercialised in the NCS since most of the subsea fields are still producing ***(10)***.

Figure 10. Severed casing-strings and WH pick up.

3.3.2 P&A PROGRAM FOR SHUT IN WELL CATEGORY 2

The status of the well may have one or two uncemented annuli where the well has been killed and reservoir isolation plugs set. The state of the well at this stage requires placement of additional permanent barrier (shallow plugs be set in casing and adjacent annuli) for complete abandonment. Thus the well necessitates a safety efficient re-entry and deployment of plugs by wireline conveyed tool string through a SILS and WCP. The SILS is deployed from the intervention vessel through moon-pool by a (MHT) lowering the well control package by guiding through guide-wires and relocates into XT.

3.3.2.1 Category 2 Well Status, Regulations and Technology Limitation

The evaluation approach of the state condition of the well after shut in is as illustrated in figure 11 accounting for all major constrains and by disregarding other problems related to material degrading and well bore geometry. Regulations and guidelines provide necessary information on how the operation should be handled, therefore it is best to look into and be careful to ascertain the technical complexity of the task and associated risks. Further it is of great importance to look especially at the technology available with regard to WI/RLWI VESSELs to achieve a safe and successful P&A end product.

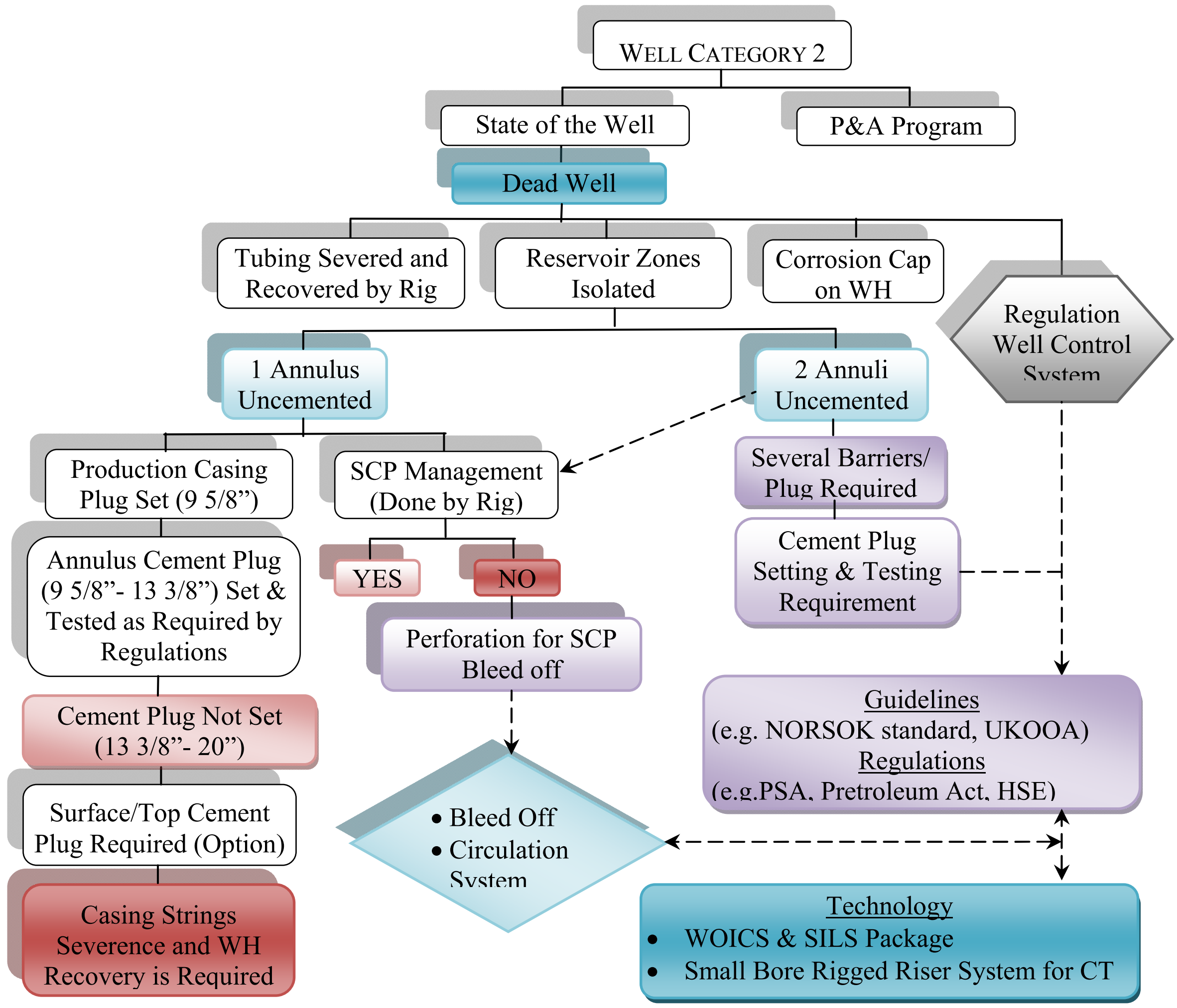

Figure 11 hierarchy approach of highlighting initial condition for shut in well category 2.

3.3.2.2 General procedure for P&A of shut in well category 2.

The scope of work for P&A is emphasized by examining the elements brought about from the technical evaluation of primary state condition of the well as illustrated in the figure above. Normally, oil operating companies provide the decommissioning plan of a field consisting of P&A program of each individual well.

RLWI / WI VESSELs perform intervention operation by deploying tools and equipments by wireline and CT respectively through subsea well control packages with limited bore diameter (small). That gives a design basis for the type and size of plugs that will be set downhole, perforation interval, and the means of taking returns (circulation) during cleaning and cement plug setting operations. The status of the well evaluated in figure 12 will provide enough information to ascertain the number of plugs to be deployed and location/ interval for plug setting with respect to rules, regulation and guidelines. Regulatory bodies as well strictly require establishment of barriers prior to entry of the well susceptible of containing non reservoir/ reservoir fluids under pressure between the casing strings. Under P&A well category 2 it is necessary to be certainly sure of the control of SCP on whether it has been done by a drilling rig.

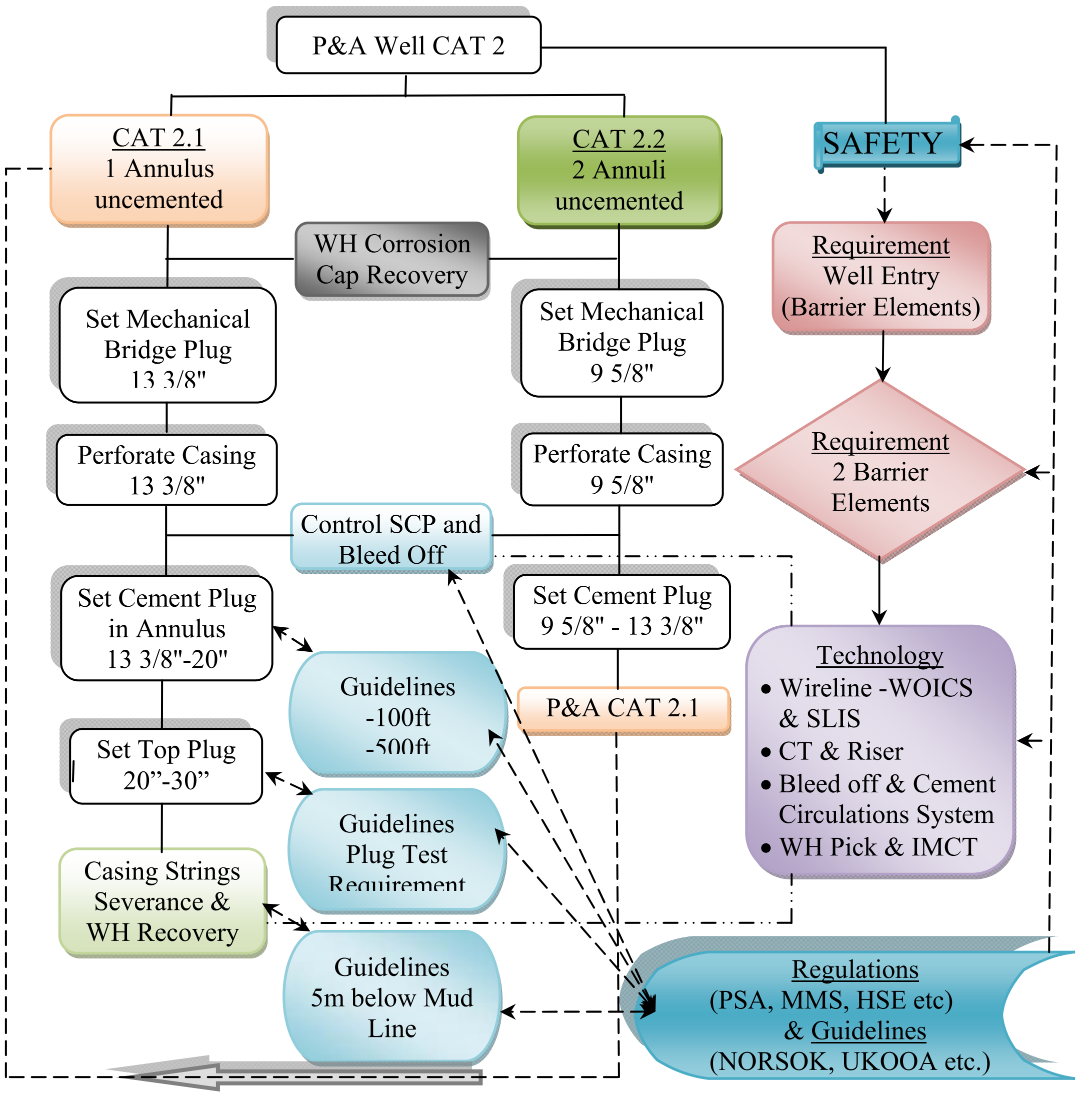

Figure 12. P&A program for P&A well category 2.

3.3.2.3 Casing Perforation and Setting of cement plug

Wireline is used to set a mechanical bridge plug and deployment of a cross over tool assembly comprising of double packers system, circulation valves and a set of explosive charges. Casing perforation is necessary to establish:

i) Access to the annulus for checking and bleed off any SCP and flush **of** reservoir fluid that may be found in annuli.
ii) Circulation path for setting cement plug by pumping and circulating cement and displacement of completion fluid present in the annuli.

The volume of circulated return can be calculated prior to the operation to account for storage consideration made with respect to the capability of separation system. It is important to consider the means to handle HC since it is not allowed to discharge any effluent **at** sea. In a small vessel one should think of the tank volume available for storage of the return.

The formula is given as: $V_r = (A_{c2} - A_{c1}) \times H_{cp} + V_{ff}$

Where, V_r = volume of return

A_{c2} = casing string

A_{c1} = tubing/casing

H_{cp} = height of cement plug

V_{ff} = flash fluid (brine, mud etc.)

Deployment procedure for BHA and cement setting.

1. Pull corrosion cap on WH. Re-enter the well.
2. Set bridge plugs by wireline below WH as required
3. Deploy BHA for casing perforation and circulation
4. Perforate casing and check for SCP and hydrocarbons.
5. Pump and circulate cement to set intermediate plug above bridge plug as required.
6. Leave cement plug to set in the annulus.
7. POOH BHA
8. Test cement plug as required.
9. Severe casing strings by IMCT
10. Recover WH and severed casing strings by WH pick.

Circulation of fluids and cement slurry is made possible through two umbilical lines (hoses) connected to the crossover tool in the figure below. Latching operation of the tool on the WH is carried out by ROV in open water. Part of the tool assembly may remain with the set cement plug forming a permanent barrier. The design basis of the umbilicals system for the BHA will be dimensioned to handle a kick expected from SCP. The advantage with this system is that it can be used for deeper waters compared to CT riser system limited depth of 600m to seabed. After the barrier element have been established, casing-strings cutting may be performed and recovery of the WH.

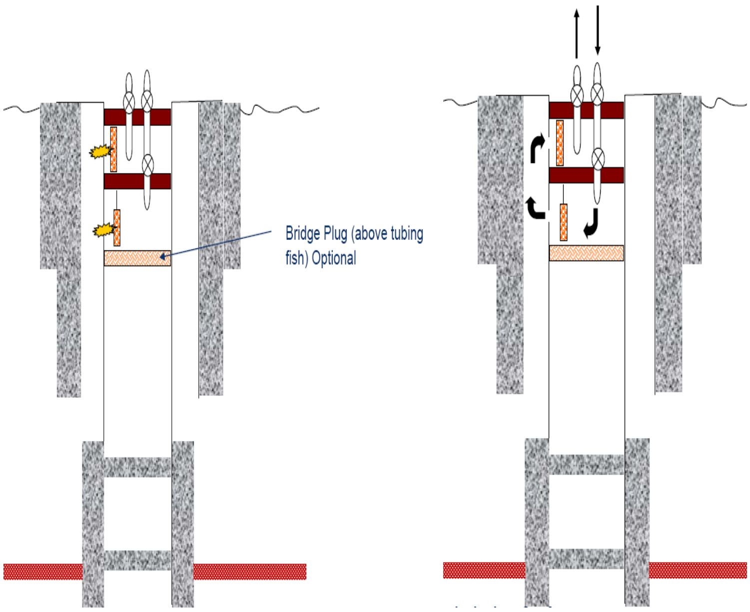

Figure 13. Deployment of BHA for P&A

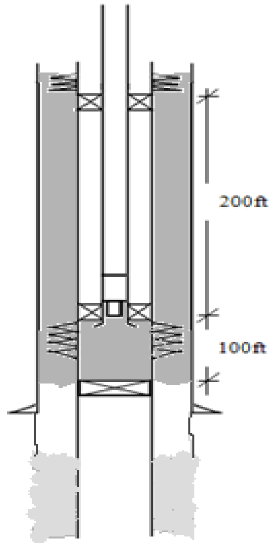

Figure 14. Alternative solution for BHA

3.3.2.4 ALTERNATIVE SOLUTION OF CT DEPLOYED BHA

This type of make up tool should be assembled with various sizes of packers depending on the space between casing strings during P&A operation and it should allow a small part of the BHA to remain in place above the set cement plug sheath. The make up length of the tool would vary from 100ft up to 500ft depending on the acceptable height of cement plug required. The tool string design should be simple such that the make up connections will comprise of fewer component parts. Circulation of cement in CT is possible since the return would make its way up through the riser system. Base on the discussion above, I have come 14. The bottom packer may be left in place as part of a permanent plug. This alternative would require first a set of perforation guns be deployed by wireline in one run, oriented and set on appropriate intervals and perforation conducted to establish access to the space between the casing strings. The gun may be dropped down and left in the wellbore.

3.3.2.5 DESIGN OF AN INTERFACE ADAPTER BETWEEN WCP AND WH.

Entry of a shut in well category 2 will require establishment of a well control barrier, since after corrosion cap is set on WH, pressure in the well might have build up over time depending on the primary cement job and if any SCP leak off path were discovered during temporary abandonment and not properly sealed (CSP controlled by drill rig). The WCP for wireline and CT (light & medium) designed fit for purpose for intervention activities on subsea well have small diameter adapter suitable for connection into XT stack. Therefore there is a need to design an adapter/interface connection for connect/nipple down the WCP to the WH; otherwise there would be a need to re-run and nipple down the XT on the WH as a connection between the WH and WCP. Taking as an example the neck for an H-4 WH (18¾”) is approximately 22-23”OD and the WCP is designed with an adapter of 13 5/8”, definitely an interface adapter will be required provide connection of the two systems.

3.3.3 ESTABLISHMENT OF INITIAL CONDITION FOR SHUT IN WELL CATEGORY 3.

P&A program requires a clear understanding of all possible situations that may be encountered in the well, such that an evaluation of all appropriate technical solutions could be put forward for achieving a successful end product. So far the regulatory authorities require safe P&A operation for shut in well Cat 3 be conducted by drilling rigs (conventional). The oil industry needs IOR of subsea well by effectively reducing costs that includes the use of technical solutions available on fit for purpose intervention vessels without violating safety issues and cause damage to the environment. Obviously it is necessary to convince the authorities that the technology available today on small intervention facilities will successfully provide the same end result in P&A operations as done by a drilling rig. To overcome constrains or challenges posed by this operation on shut in well category 3, a careful examination of what necessary would affect HSE issues has be conducted without disregarding the regulations and guidelines laid down by regulatory bodies and by local and international standards respectively. The shut in well category 3 is described in Table 1 chapter 1 and further a detailed evaluation of the state of the well is carried out as illustrated in figure 15. The emphasis on the flow diagram describes the technology dependence to meet the requirements set by regulatory bodies and standard with focus on a safe and cost efficient P&A operation of shut in well category 3.

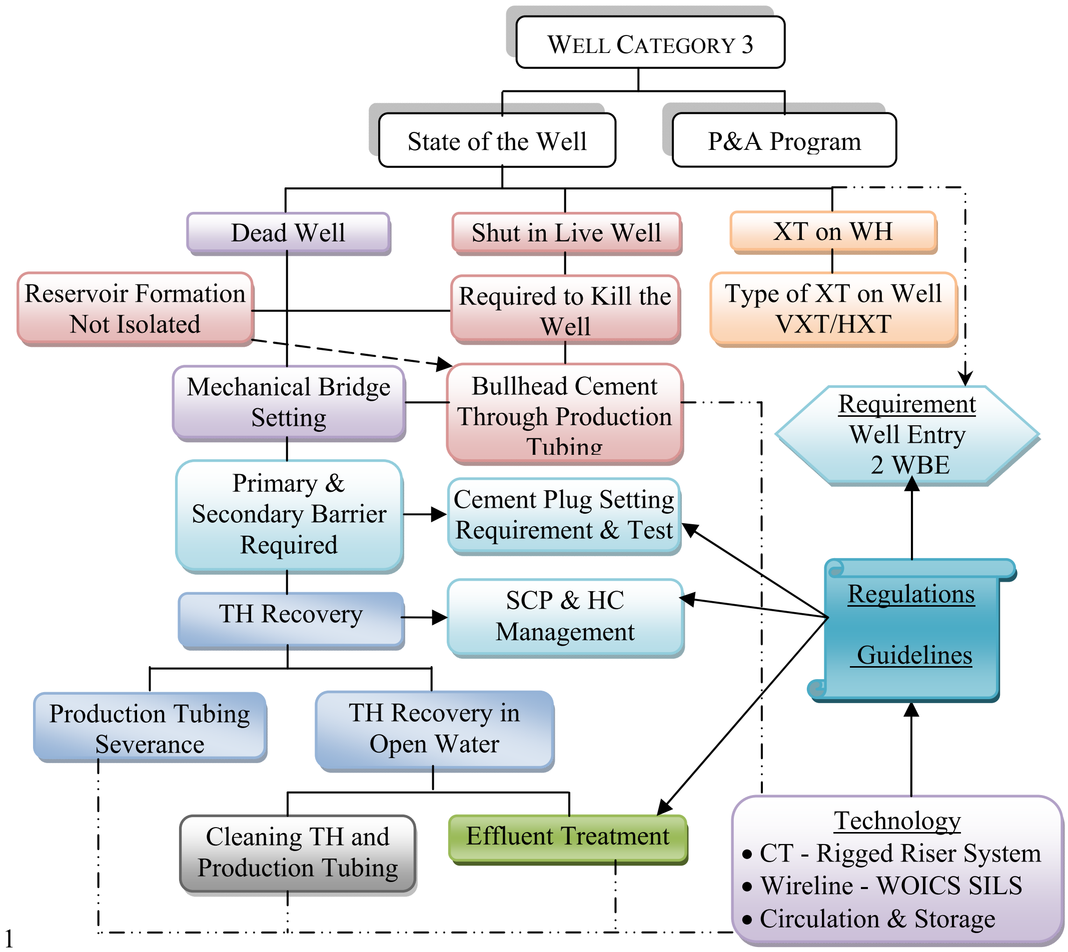

Figure 15. Hierarchy approach highlighting initial condition for shut in well category 3.

3.3.3.1 P&A PROGRAM FOR SHUT IN WELL CAT 3.

The P&A program is based on shut in well pre-condition, technology available for conducting the operation safely and successfully as well as satisfaction of rules, regulations and guidelines. As seen from well intervention perspective, most of the operations are conducted through XT bore, and the WCP dimension (length and internal diameter) further gives limitation to the dimension for necessary BHA to be deployed in the well.

3.3.3.2 KILL THE WELL AND ESTABLISHMENT OF WBES.

Primary for a live shut in well category 3, a kill pill will be required and squeezed into the reservoir formation to block flow of the reservoir fluids into the wellbore.

Kill weight calculations:

Kill weight to RT (brine): $$w_{kill} = \frac{[(p_{\max fb})[bar] + s_f[bar]]}{[d_f * 0.0981][m, TVD - RT]} + \frac{0.647(t_2 - t_1)[bar]}{1000}[sg]$$

The kill hose margin: $$w_{kill,m} = \frac{w_{kill}[sg] * d_{RT-WH}[m] - SW_{sg} * d_{RT-WH}}{d_f[m, TVD - RT] - d_{RT-WH}[m]}[sg]$$

Therefore; Kill weight = <u>Kill weight to RT (brine) +The kill hose margin</u>

Where; w_{kill} = kill weight to top of reservoir formation

$p_{\max fb}$ = maximum formation pressure at top of perforation $[bar]$

s_f - safety factor for overbalance $[bar]$

d_f = depth to top of existing perforation $[m, TVD - RT]$

0.0981 =specific gravity $[sg]$

$0.647(t_2 - t_1)/1000$ = correction factor for thermal expansion of brine $[bar]$

$w_{kill,m}$ = kill weight for hose margin $[sg]$

d_{RT-WH} = height RT to WH $[m]$

SW_{sg} = sea water specific gravity $[sg]$

d_{SW-WH} = SW depth to WH $[m]$ ***(15)***

Thereby the kill pile would be followed by bullheading and squeeze cement into the formation to prevent any leakage or influx of HC into the wellbore thus creating a primary well barrier. Setting of a mechanical plug is an alternative solution (option) instead of bullheading and squeezing cement into formation in a dead well. Technical solutions for bullheading cement slurry and mechanical plug setting are as follows:

- Wireline operation of P&A.
  - Cement slurry bullheading is achieved by pumping through production tubing via umbilical kill lines or production hub without taking the return.
  - Mechanical plug set by wireline.
- CT operation

- Cement slurry bullheading is achieved by pumping through CT and **possible** return may find way up through a small bore riser system.
- Mechanical plug set by CT.

Secondary well barrier for P&A will be set as illustrated in figure 16 where the live well is plugged and cemented until is brought to category 1. At this stage it is safe to enter the well through open water and the campaign for WH recovery is performed.

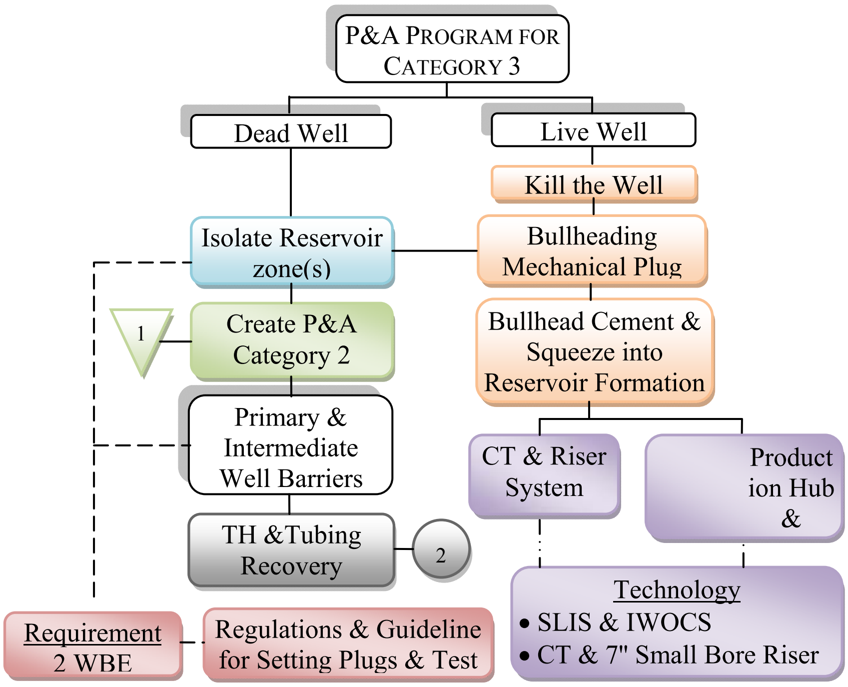

Figure 16. P&A for shut in well category 3

3.3.3.3 RECOVERY OF TH AND XT

Normally TH and the production tubing are recovered through the riser system when PA is carried out by a drill rig. Drilling BOPs and riser systems for WO and recompletion work are designed with full bore to accommodate and run the TH. The recovery of TH by a small intervention facility poses a challenge since it has to be lifted up in open water and consideration should be made as well to account for the sitting location of TH. The type of XT on the well came into focus since it provides necessary information on the scope of the job to be done prior to recovery of the TH as seen in figure 17. The TH is located on the WH under XT in a completed well with a VXT in contrary to HXT completed well where the TH sits in the XT. The later allows the TH to be removed from the WH without recovering first the XT.
Thus simplifying perforation and setting of top cement plug.

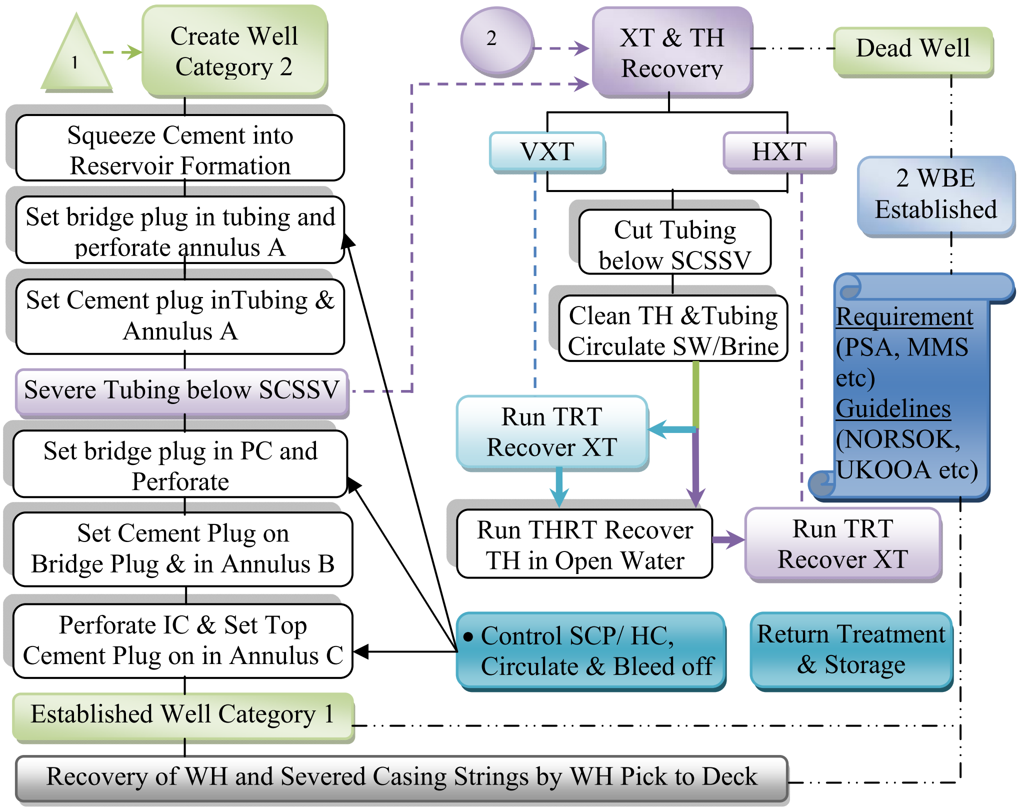

Figure 17. P&A procedures for shut in well category 3

It is expected that annulus A is always filled with non corrosive packer fluid which prevent corrosion on the casing and tubing. Annulus B is filled with completion fluid like OBM, and it is expected that most of heavier compounds (weighting agent) in the mud will settle down after time living a light medium above it.

The following is the procedure for setting mechanical bridge – and cement plugs in the wellbore including illustration of the process involved figure 18 to 20 :

1. Bullhead and squeeze cement into reservoir perforation. For a dead well a mechanical packer could be set over the production zone in the 7”” production tubing and cement plug set over it.
2. Test cement plug according to provided guidelines and requirements (pressure or weight tested).
3. Set bridge plugs in the production tubing across production packer.
4. Perforate tubing above bridge plug to establish access to annulus A (7"-9 5/8") and control SCP.
5. Set cement plug in annulus A. Circulate of the annulus fluid will be through annulus access valve.

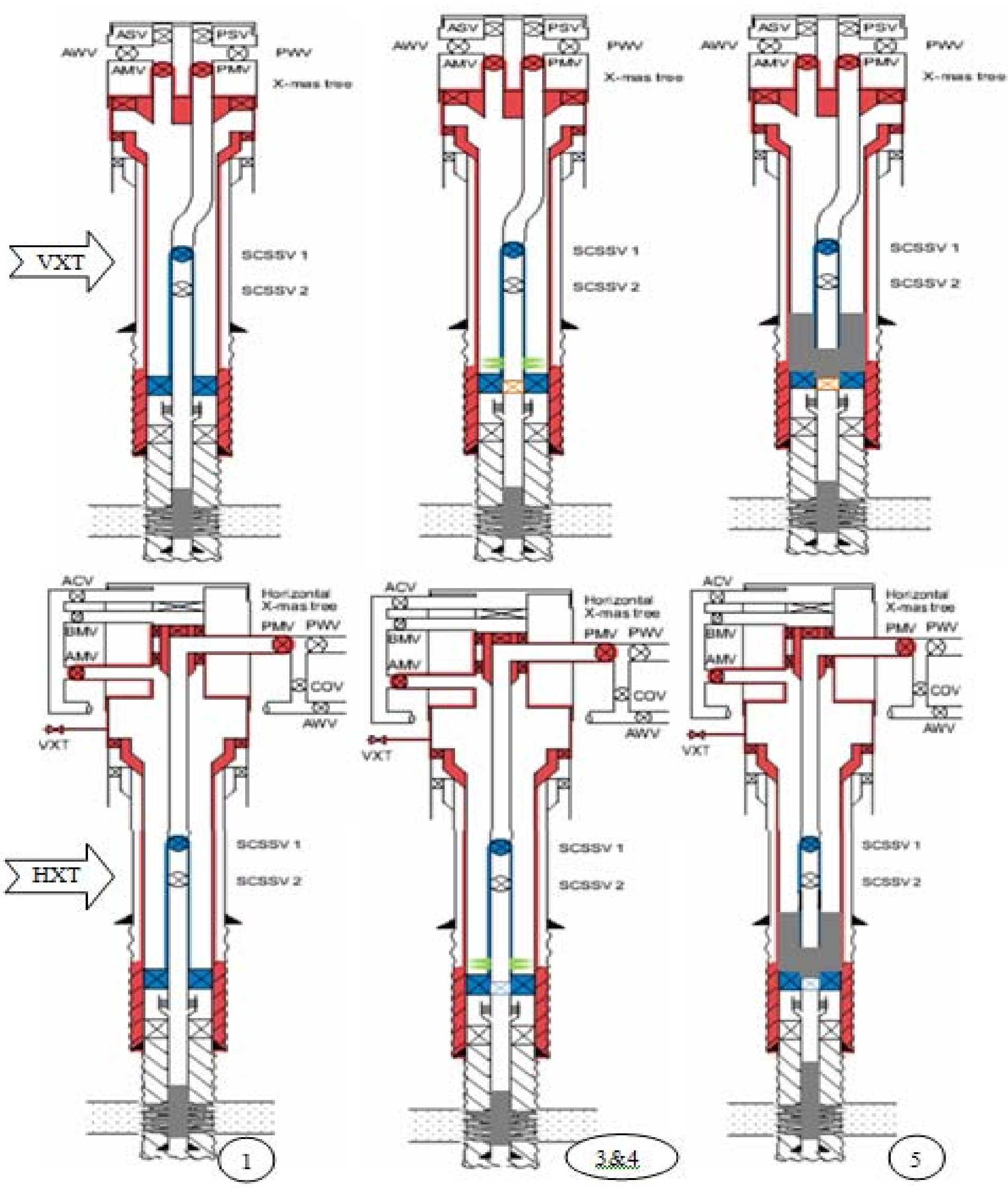

Figure 18. P&A procedure, steps 1 to 5 for Vertical and Horizontal XT.

6. Severe/cut production tubing below SCSSV. This can be done by **tractor** with a cutter tool deployed by e-line.
7. Circulate brine/ sea water to clean the tubing by flushing. Consideration on oil water separator capacity (philosophy of zero discharge to sea) and storage.
8. The TH is recovered through open water. In a well with VXT, the tree will be recovered first and the TH underneath recovered to surface. In the case of HXT, TH will be removed easily since it is accommodated in the tree itself and followed by retrieval of the XT.

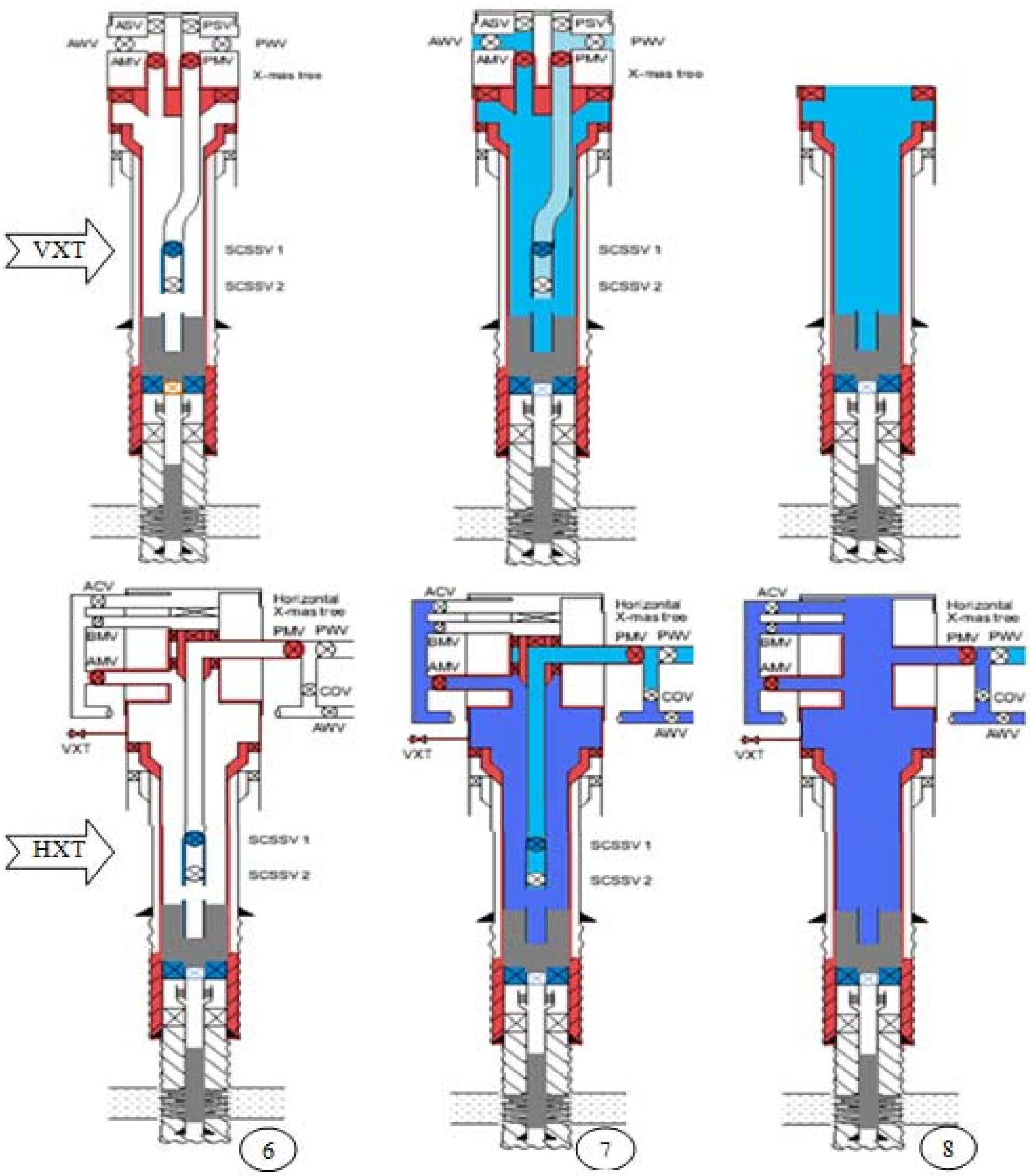

Figure 19. P&A procedure, steps 6 to 8 for Vertical and Horizontal XT.

9. Set bridge plug in 9 5/8", perforate to access annulus B (9 5/8"-13 3/8") and control SCP.
10. Set cement plug and test for integrity.
11. Perforate intermediate 13 3/8” casing and set top cement plug between 13 3/8” - 20” casing
12. Low down IMCT and latch the WH Pick, severe casing strings and recover with the WH.

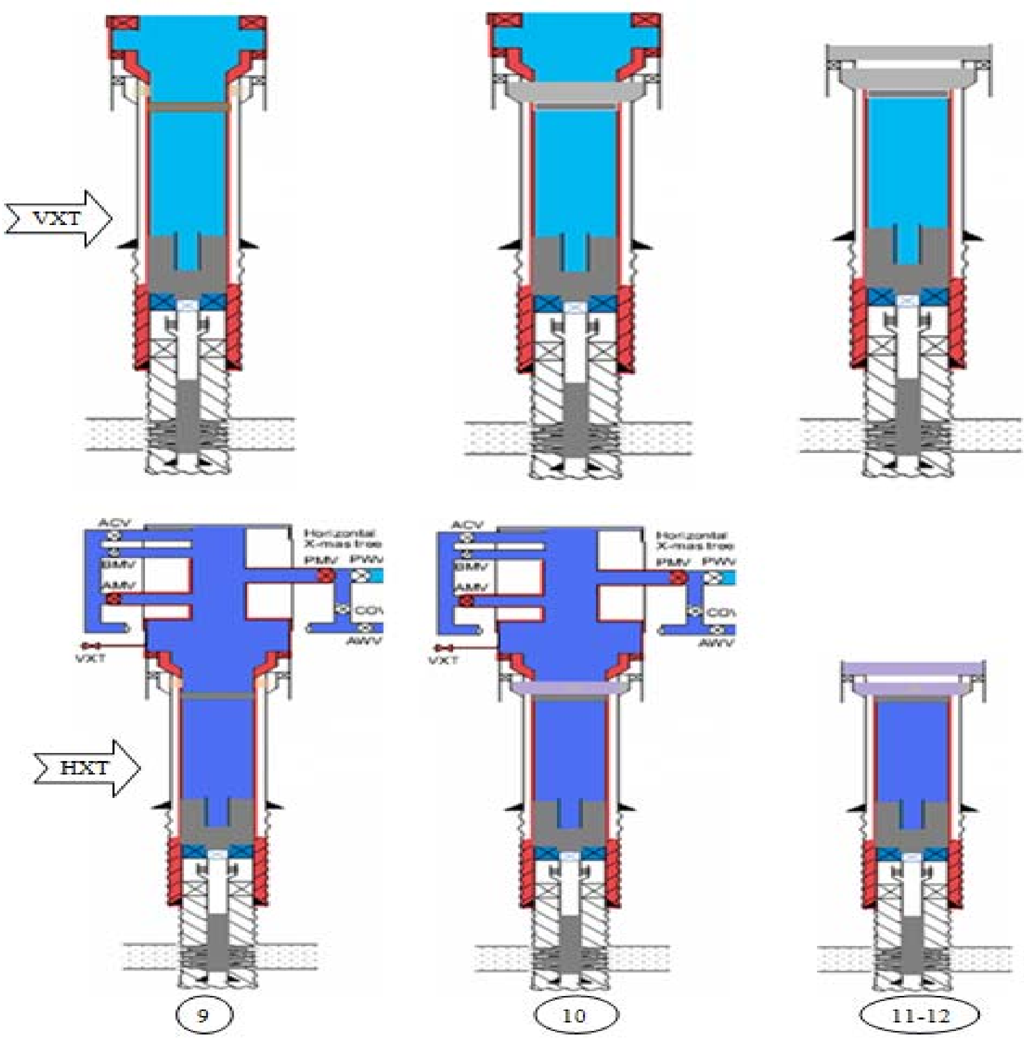

Figure 20. P&A procedure, steps 9 to 12 for Vertical and Horizontal XT.

3.4 TH AND PRODUCTION TUBING CLEANING

P&A operation by use of small facilities requires removal of TH in open water, discussed early, exposing the wellbore to the open sea as well. Thus to avoid HC spill to the sea, it would be necessary to clean the TH while still in the well. Normally this is not a problem when a drilling rig is used for P&A operation where the full bore of the riser allows TH to pass through it. The flushing fluid is required to have sufficient physical characteristics to remove unwanted material from the wellbore.

In case sea water was used for the flushing operation as a flushing fluid, it has to be treated onboard before discharge to sea. Normally at sea oil water separators are used to separate oil and water mixture. For the case where brine is used for flushing operation, a means for recycling and recovery of brine should be arranged. The HC separated will be flared or transferred into storage tanks. A process system including flare as a possible means for handling upstream flushing water contaminated with HC during CT operations is discussed in subchapter 5.6.1.1.

3.5 WIRELINE SET PLUG AND PACKER

Oil equipment suppliers like Schlumberger have developed expandable plugs that can be deployed by wireline through tubing. This eliminates dependence on the use of workover rig to perform P&A operations. Expandle plug like PosiSet anchored elastomeric plug provides a seal which is similar to that achieved by cast iron plugs. *The Casing Packer Setting Tool (CPST) provides a reliable method of deploying plugs and packers in the wellbore during completion, isolation, or abandonment, where a downhole electric motor within the mechanical plug-back tool (MPBT) Setting Unit (MPSU), is used to contract the elastomer sealing assembly to form a firm seal against the casing wall.* The plugs have an expansion ratio of 3:1 as see attachment 4. The anchor system on the plug acts as slips by providing satisfactory grippe against the inner walls of the casing keeping in the plug in place while cementing is placed on top at a height above 3m. The smallest plug can withstand 25,000-lbf [111,205-N] and the largest (95.8-in. [24.45-cm]) plug can withstand 90,000-lbf [400,340-N] force ***(23)***.

3.6 CEMENTING

It is required that the material used as well barriers for P&A should withstand the load/environmental conditions they are exposed to for as long the well is abandoned. Long term integrity of the plug material will be performed by weighting or pressure (NORSOK standard chapter 9, and UKOOA guidelines paragraph 5.4). Detailed information of cement required properties to provide desired characteristics for a specific operation are discussion in chapter 2. *The design of abandonment well barriers consisting of cement should account for uncertainties relating to:*

- *downhole placement techniques,*
- *minimum volumes required to mix a homogenous slurry,*
- *surface volume control,*
- *pump efficiency/ -parameters,*
- *contamination of fluids,*
- *shrinkage of cement.* (NORSOK standard D10 rev 3)

3.7 REMOVAL OF DOWN-HOLE AND SUBSEA EQUIPMENT

The are no requirements for removal of downhole equipments provided that proper isolation of the well is achieved. Part of the completion may be left in place, but cables and control lines which are regarded as potential source of forming inflow paths should be removed and they are not considered to form part of permanent barriers (UKOOA paragraph 3.3).

Consideration should be made to other users of the sea, therefore subsea equipments must be removed to avoid hazard situation. Common practise is to remove the WH and casing strings down to 5m below seabed. The requirement is provided to account for fishing activities in area where wells have been permanently abandoned. Revision of the recommended depth for cutting subsurface and subsea equipment is important and it is required to be done individually on a case-by-case bases for each well with respect to prevailing local condition like sand waves, soil, sea bed scouring and sea current erosion. In case of a concrete foundation on seabed, it is required that no casing string should protrude causing obstruction above such a structure. (UKOOA guidelines & NORSOK standard D10 rev 3)

4.0 GENERAL ABOUT THE SET OF REGULATIONS AND GUIDELINES FOR CONSTRUCTION OF VESSELS AND MOBILE FACILITIES

Since the thesis work has more focus on offshore petroleum activities, there will be less focus on the details and information regarding rules applicable for service vessels registration with respect to that of a facility which must be fulfilled to meet the requirement for its registration. It is important to differentiate between a "standard" vessel as AHTS and a fit for purpose intervention vessel as RLWI.

4.1 VESSELS

Generally a vessel is built according to the rules set by the Flag State, where in Norway the rules are available in the Green Book published by the Norwegian Maritime Directorate (NMD) and as well it should fulfill the classification requirements imposed by classification society like Det Norske Veritas (DNV). This implies that a vessel certification will have to comply with only few requirements and regulations compared to a facility which in addition should comply fully with PSA regulations. It is observed that the regulations in the Working Environment Act can partly or fully be applied on a vessel and it is required that for a vessel to operate in the NCS, it shall also be subject to the Law of Seaworthiness, where this rule is not exceptional as well as for mobile offshore units. In paragraph § 1 it is stated that;
"Norwegian vessels with 50 registered gross tonnage and more shall be subject to a control according to this law. The control includes every single aspect which assumes or can influence the vessel's seaworthiness".
Offshore mobile units' construction is governed by guidelines and regulations set by the Norwegian Petroleum Authority-PSA concerning petroleum's activities. In addition PSA made other regulations applicable in full or in parts through the HSE regulations and the temporary regulations. Such regulations are basically those set by the Flag State, like NMD, and classification society eg. DNV. Further more, PSA recommend, as seen in figure 21, for offshore units the application of guidelines recommended for maritime operations by recognized standards like in NORSOK Standards in Norway and international maritime regulations set by IMO. PSA does not set construction requirements, guidelines or maritime safety rules for vessels but it always refers to NMD regulations with matter related to offshore activities especially when dealing with rules and regulations concerning for example standby vessels and AHTS and permanent storage ship shaped vessels.
When it comes to the general requirements for construction and fitting of vessels operating offshore in the Norwegian Continental Shelf, it is regulated by the concerned vessel's Flag State. This implies that the Flag State of the vessels is to be responsible for regulating and supervision of the vessel's maritime safety, i.e. construction, stability, crew, safety for certification and navigation.
The term installation is applied in both PSA and NMD regulations though it is clearly observed as a definition under NMD regulation of a mobile offshore unit in contrary to the term facility under the PSA regulation. For clarity the following diagram describes the Norwegian rules and regulations environment with respect to outfitting, construction and certification of a facility and a vessel.

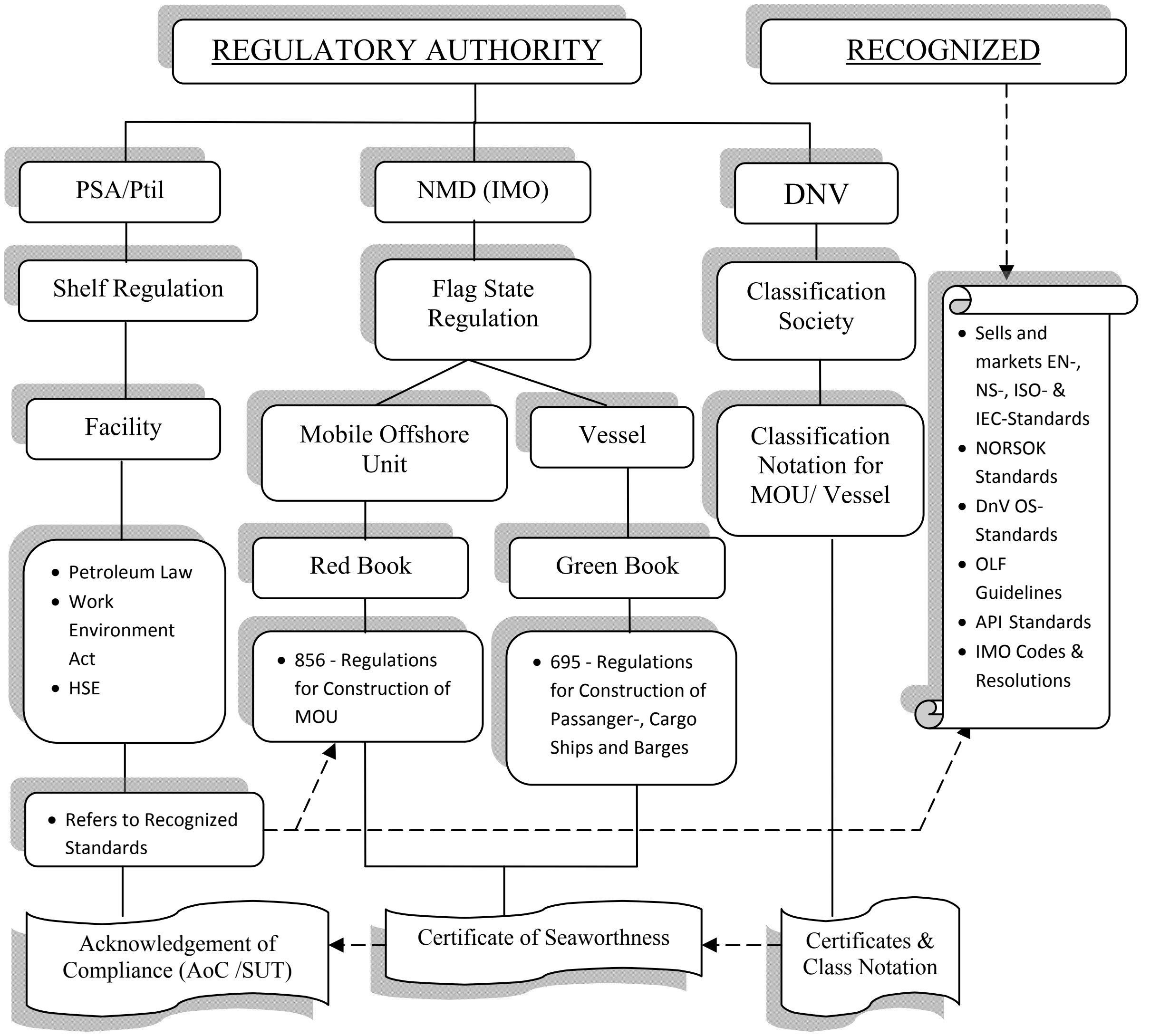

Figure 21. Flow diagram illustrating the rules and regulation environment in the NCS.

4.2 MOBILE FACILITY

The set of rules for petroleum activities, differentiate clearly mainly a facility from a vessel. These rules set more comprehensive and stringent requirements for installations than vessels. However a facility in order to taking part in petroleum activities have to be qualified to receive an Acknowledgement of Compliance (AoC) as a result of the law dated 1st January 2004 which says that AoC is mandatory to all mobile facilities.

In Norway, a facility is built according to the PSA regulations and should as a recommended practice comply with the Flag State requirements set for Mobile Offshore Units as stipulated in the Red Book of NMD to be registered in the Norwegian shipping register. PSA's regulations cover Working Environment Act and the Petroleum Act as well it refers to recognized standards like NORSOK standards. Regulations which are stipulate in Framework HSE, Management, Task/ Duty Information and Activities are concerned for both new and existing facilities.

Under PSA regulations in Framework HSE section 4 d, a *facility* is defined as an installation, plant and other equipment for petroleum activities, however not supply and support vessels or ships that transport petroleum in bulk. The term facility also comprises pipeline and cable unless otherwise provided.

It is mandatory for installations to comply fully with both the regulations set in the Petroleum Act and the Working Environment Act in contrary to a vessel. It is evident from *subsection 1*

litera d second indent, certain limitations are made to the substantive scope of application in relation to the Petroleum Act which entail more limited application of the Working Environment Act to some extent as a vessel function is concerned.
The NMD subdivision for mobile offshore units certifies all units which operate under Norwegian flag. It also maintains already existing Letters of Compliance for installations under foreign flags which have documented that they satisfy Norwegian requirements. The subdivision provides assistance to PSA in matters related to maritime authorization in the Norwegian Continental Shelf.
NMD uses a term unit according to the regulations FOR 1987-09-04 nr. 856: Regulations on construction of mobile offshore units, where paragraph §1.1 defines a unit as: "a mobile platform, including drill ship, which is equipped for drilling an under sea petroleum deposits, and mobile floating platform for other uses than drilling under sea petroleum deposits".
Further some parts of NMD regulations are applied additionally concerning mobile offshore units:

- regulations § 38 for ballast systems
- regulations § 63 for stability with respect to §21
- regulations § 64 for anchorage, mooring and positioning
- regulations § 65 for turret

DNV regulations and standards for mobile facilities are considered to be leading in the world, and these are often used as references in the industry. Some countries' authorities approve maritime certificates and give approval to facilities operations with reference to the DNV class notation. In Norway the DNV standards are referred to in the set of PSA regulations where these classification regulations and standards are accepted as basis for consent and acquisition of an AoC for a mobile facility. DNV has international experience with offshore classification; its classified units operate world wide according to the regulations in force issued by IMO. Mobile facilities with DNV class operate under different kinds of climatic and oceanographic conditions and satisfy the strictest requirements set, for example in frozen seas. For mobile facilities in general, there will always be a list of deviations, since it is not possible to comply with all the requirements at all times. This is due to ever changing regulations, for example, NMD's regulations in the Red Book for mobile installations are revised every 4th year, such that a new revised version issued will be the one in force.

4.3 THE DIFFERENCE BETWEEN A VESSEL AND A FACILITY

As mentioned in the previous subchapters, the requirements for vessels and facilitis would be very different. In this subchapter, a focus is made in explaining the main differences between vessels and installations by using few key factors in order to present more clearly in the technical aspects. The requirements for the mobile facilities are in many aspects considerably stricter in relation to ship regulations as see in NMD regulations §6 & §7 for mobile offshore units, for example:

4.3.1 HULL AND REQUIREMENTS FOR CONSTRUCTION MATERIAL (STEEL GRADE)

The NMD Red Book for registration of mobile offshore units, stipulate in chapter V §6 that a unit should be built to suit unfavorable combination of maximum environmental loads, where under PSA facility regulation section 10 Loads, load effects and resistance it is stated that "*accidental loads and environmental loads with an annual probability greater than or equal to 1x10^{-4} shall not cause the loss of a main safety function*,". PSA requires better documentation on steel quality for approval and DNV have set standards with regard to explosion analysis. The facility must also be subjected to several analyses for design verifications related to structural integrity thereto increasing capital costs as direct consequence. PSA refers to the application of DNV offshore standards which give the notation 1A1 to a mobile offshore unit with hull, marine machinery and equipment found to be in compliance with the basic (common) requirements of the applicable DNV rules.

Additionally there must be separate systems with fire class bulkheads between engine room and engine control room. The installation must also be equipped with an emergency bridge in case of fire on the main bridge with requirement for fire class walls between interior and main deck in case of hydrocarbon fire. The requirement states that the fire should be contained for 60 minutes without spreading from one engine room to another, or from one bridge to another.
Since there is a great danger of leakage of hydrocarbons on a deck there is a requirement for a separate collecting system or so called "hazardous drain (fluid)". The size of the drainage system would depend on which class an installation is built according to.

4.3.2 DAMAGE STABILITY AND BALLAST SYSTEM

Stricter requirements are also applied for an installation than those for a vessel when it concerns stability. An installation would have a requirement to tolerate a leakage in to compartments after a possible collision while for a vessel the requirement is to tolerate leakage in one compartment without having a serious effect on stability. Stability regulation in §21, requires that the waterline into the final state of equilibrium after flooding taking into account the effect of wind, should be below any openings, such as air pipes, ventilators, that may lead into progressive flooding of the compartment.
The ballast system should have at least 2 independent pumps arranged such that ballast could be pumped in the event of failure of any pump. The ballast system ought to be capable of changing the installation draught from any transit draught to survival draught within 3hours.

4.3.3 WORKING ENVIRONMENT WITH RESPECT TO NOISE, VIBRATIONS AND ILLUMINATION CONDITIONS

4.3.3.1 WORKING ENVIRONMENT

The Working Environment Act requires employees' participation during design verification phase in order to shape their working place (this requirement does not apply to vessels). Under Working Environment Act section 2-3. Part (1) the employees are required to provide cooperation on the design, its implementation and follow-up of the undertaking's systematic work on issues related to health, environment and safety. Further more, employees shall as well take part in the organized safety and environmental work of the undertaking and shall actively cooperate on implementation of measures to create a satisfactory and safe working environment ***(6)***.

4.3.3.2 NOISE

Installations are required to have better noise reduction and noise damping measures (e.g. super silent thrusters). It is required to locate in separate rooms noisy equipment and equipment with high structure-borne sound emission levels and areas with noisy activities e.g. lay down areas, and workshops, within the immediate vicinity of areas with a noise level limit of 50 dB(A) or below, e.g. offices, hospital, central control room, sleeping/recreation areas.

Separation of unmanned machine rooms (UMS) with several noise sources is required such that maintenance work can be performed on machines not in operation without being exposed to noise levels above 90 dB(A). NORSOK S-002 section 5.5.4 as well requires that maximum exposure noise level not exceeding 83 dB (A) for an individual employee during 12hrs of a work day.

4.3.3.3 VIBRATIONS

It is observed that vibration limits are based on boundaries given in ISO 2631, where in NORSOK Standard S-002 are referred, and under section 5. 5.5.0-2 Annex D of the standard it is required that the application of vibrations exposure acceptability based on 12hrs working day be used for human beings. The maximum limits for continuous whole body vibration from machinery and equipment cover the range from 1 Hz to 80 Hz in which the major body resonance occurs.

4.3.3.4 ILLUMINATION

In the design of the lighting, the level of illumination and location of lamps shall make it easy to see obstructions, steps in corridors, walkways etc. Under the of NORSOK Standard section 5.6.0-13, guidelines are provided where different levels of luminance and light colours may be required to create comfortable environment. "*Warm different colours should be used in cabins and recreation areas where the lighting levels are below 500 lux and high colour temperature, whiter light, should be used in areas with high lighting levels*" like in engine rooms and confined spaces.

4.3.4 ANCHORAGE / DYNAMIC POSITIONING WITH RESPECT TO DP CLASS

The NORSOK Standard J-003 Rev. 2, August 1997 provides guidelines for mobile offshore units where they shall equipped with DP class from 1-3 for varies operations (see table 1 in NORSOK J-003). For wireline operations on subsea wells with SLIS the unit should be equipped with DP class 2 to comply for the minimum requirement, i.e. there must be independent references for the DP system.
For DP operators the standard refers to training in accordance with NMD Guideline No 23: "Certification of DP operators", further training from other institutions than those listed in the guidelines may be accepted. The NMD Red Book regulations § 6 (857/87) requires that a unit be kept in place with necessary accuracy and reliability under all weather condition.

4.3.5 INTERIOR REQUIREMENTS FOR CORRIDORS, DOORS AND LADDER

The regulations in the NMD red book give standard specifications for a facility interior construction where corridors should have minimum size to allow stretcher to pass without constrains and protruded area, must be equipped with portable breathing apparatus, and fitted with standard size doors with breadth of 600mm and height of 2050mm.
It is required as well in §15 that an installation be fitted with stairs of standard size steps 150x1600 instead of ladders for crane operators, further should stairs have railings and an inclination less than 50^o. Ladders could be used with maximum height of 9m, and where the height exceeds 12m ladder should have 6m interval and be fitted with a rest platform. It is required that all beds shall stand over deck floor with minimum length of 2.2 m

4.3.6 MACHINERY AND EMERGENCY POWER SUPPLY

Generator/engines have their own external fresh air and exhaust (pipes) ventilation system for turbocharger with no gas detection system. However, turbocharger's air suction system is

required to be equipped with a Rig Saver (applied as valves). The purpose of the valves is to chock the engine during shut down so that it doesn't get any air/gas.
The Rig Saver functions as a chocking device when an engine starts sucking in gas. The HC gas when sucked, will increase combustion and thereby higher engine revolutions. In order to maintain desired revolutions, the engine's regulator will provide less fuel to the engine. This works fine until the moment the engine sucks inn so much gas that it operates only on gas. Then there will be an increase in revolutions again and lead to no possibility of regulating engine speed such that there wont be any other means of stopping the engine. At this stage the Rig Saver steps in and chokes/stops the engine. This prevents the engine to overspeed which may lead to total breakdown, therefore it requirement for an installation to be equipped with a complete EsD system which is not necessarily needed on a vessel ***(17)***.

Facilities are required to be equipped with an independent emergency power supply which is arranged and constructed to provide continuous power in not less than 18 hours in unfavorable inclining angle with respect to stability regulations paragraph §21. The protocol for certification of emergency power supply under paragraph §11, requires test the performance of a prototype under the inclination angle of 22.5 degrees combining with 10 degrees for trim especially for ship shaped units. The test should be conducted with maximum loading for not less than 4 hours. This is a general requirement that concerns as well vessel as described in the NMD regulations. *(FOR 1987-09-04 nr 856: regulations for construction of mobile offshore units)*

4.3.7 STRICTER REQUIREMENTS FOR LIFE SAVING APPLIANCES

Chapter 2 paragraph §9 of NMD Red Book set requirements for life saving appliances and launching arrangement of life boats, where under the guidelines on regulations related to design and outfitting of offshore facilities in Petroleum Activities, regulation iii-iv on Emergency Preparedness resection 40 on equipment for rescue of personnel, an installation is required to be equipment with two independent man overboard boat systems (MOB boat systems).
The requirements of interior and life saving appliances on a facility will also be stricter than that on a vessel, i.e. an installation must satisfy as well NORSOK standard in the following aspects:

(i) hospital, plus a prepared emergency hospital,
(ii) more lifeboats of the freefall type.

4.3.8 FIRE-, GAS DETECTION PROTECTION/PREVENTION SYSTEM

NMD requires that the mobile offshore unit be outfitted with gas detection and alarm system of two levels of concentration. For HC gas the low level, LAL, should be 20% and 60% for high level, LAH, for H_2S gas a low level of concentration should be at 10ppm and high level set at 20 ppm (Red Book §25). Under paragraph §26 it is required that emergency shut down of ventilation system for accommodation to be activated at LEL, that includes shut down of damper / throttle valve /flap for air uptake for installation and machinery.

4.3.9 MANNING REQUIREMENTS WITH RESPECT TO TRAINING AND CERTIFICATION

For the crew on a vessel normally there would be 4-4 work plan on normal bases, while on a facility it is required by the regulations that the personnel should follow 2-4 work, thereby lead to an increase in operational costs since more crew will be needed fro an installation.

Under the Working environment Act section 10-3 on work schedule states that the schedule shall be prepared in cooperation with the employees' elected representatives and be accessible for employee at the latest, two weeks prior to its implementation. In section 10-4, it is specified that normal working hours must not exceed nine hours per 24 hours and 40 hours per seven days. Overtime work must not exceed ten hours per seven days, 25 hours per four consecutive weeks or 200 hours during a period of 52 weeks ***(6)***.

4.3.10 ERGONOMIC DESIGN

PSA facility regulation **section 19** requires that the work areas and work equipment be designed and located to avoid employees' subjection to adverse physical or mental strain as a result of manual handling, work position, repetitive movements or work intensity, which may cause injury or illness. Workplaces and equipments ought be designed and placed to reduce danger of mistakes that may be significant to safety. Individual work positions shall be provided at workplaces to enable the possibility of work operations to be carried out safely.

4.4 REGULATIONS IN THE PETROLEUM ACT WITH REGARD TO APPLICATION ON A VESSEL OR FACILITY

There has been a discussion for a long time regarding the difference between a vessel and a mobile facility. Based on the few regulations which were undergone and focused on, its shows there are clear guidelines of what differentiates a vessel from a facility, but the discussion is often about which tasks that can be done by a vessel, and which tasks that must be conducted by a facility. In the regulations it is stated clearly that all activities with equipment for petroleum activities, with exception of freight if not specified otherwise, would require a facility, refer to the Act relating to petroleum activities §1-6, d.
In the Act relating to petroleum activities §1-6, c a petroleum activity is defined as:
"*petroleum activity, all activities associated with subsea petroleum deposits, including exploration, exploration drilling, production, transportation, utilization and decommissioning, including planning of such activities, but not including, however transport of petroleum in bulk by ship*".
Therefore it is not determined that all type of petroleum activities would require a facility since the concept petroleum activity can be discussed and varies in a scope. This means that every single case must be discussed and evaluated before one can say anything about which rules must be followed. So it is the activity which will determine the use of a facility or a vessel.
In the guidelines for Framework HSE §2 there is an information that opens a discussion regarding this moment. It states that among other things, activities as simple pumping activities without well control (entry to the well barrier) or disassembly on secured and abandoned wells, as well as maintenance work on well template and wellheads without penetration of well barriers are considered as activities which can be done by a vessel.
For mobile facilities which are within maritime operational concept, section 2 about appliance of maritime regulations in the petroleum activities in the Framework HSE, opens up for one to choose to use other relevant technical requirements according to NMD regulations in addition to technical requirements according to the petroleum activities (MOU regulations) within the framework HSE section 3 on the use of maritime legislation in the petroleum activities. Section 3 in Framework HSE states as follows:
For mobile facilities which are registered in a national shipping register and which follow maritime operational concept, all relevant technical requirements in NMD regulations stated after revision in 2003 and regulations of 2007 and 2008 mentioned in the third paragraph, together with supplementary DNV classification requirements, or international flag state

regulations with the class regulations achieving the same safety level, can be used as basis for alternatives of technical requirements which are indicated in the Petroleum Activities Act, with the following specifications and limitations:
This paragraph applies to only regulations related to maritime matters which are not directly connected to the petroleum activities which a facility would conduct. The paragraph does not comprise the following provisions:

- drilling and process equipment,
- universal sound and light alarms,
- equipment used for transportation of personnel and requirements to transportation of personnel on the drill floor,
- other provisions on the working environment,
- the activities to be carried out in the petroleum activities.

PSA can set additional requirements regarding aspects as mentioned in §3 when these requirements can be explained based on safety related considerations. The regulation can also among other things include mobile facilities, well intervention vessels, multiuse installations and some types of mobile production facilities. The regulation includes therefore no immobile installations, mobile production installations which are permanently placed, storage ships and similar, i.e. an installation which shall operate on a field in a long time with permanent place and therefore does not satisfy assumptions within maritime operational and maintenance concept.
This leads to a conclusion that for given activities one can differentiate between a vessel and equipment which would be used for the activity. Any exemptions granted by the flag state authority shall be assessed and presented to the PSA for approval if they are of significance to safety in the petroleum activities. Meanwhile an AoC will be granted by PSA to the fact that the technical condition of a mobile facility and the applicant's organisation and management system are considered to be in compliance with relevant requirements in Norwegian shelf legislation.

4.5 COST EVALUATION FOR WELL INTERVENTION BY THE USE OF MOBILE FACILITIES

The focus on safety efficiency and cost reduction are the key parameters in the innovation of mobile facilities in the oil and gas industry. The IOR need especially for subsea wells is challenging and it is a drive mechanism for development of new ways to approach and conduct intervention/ maintenance activities on subsea fields. Thereby, new built state of the art and fit for purpose vessels compete with existing drill rig to perform work-over and intervention tasks. Operators focus in cost reduction during the production life of the oil/gas fields without costing the environment and jeopardy of personnel safety and loss of property.

Well intervention deployment technology is detailed dealt in chapter 5 with special emphasis on the conventional and new generation technology available for performing the task safely and effectively. In this subchapter, cost comparison is the main focus with the evaluation of performing intervention activities without violating stringent requirements and regulations set by international and local regulatory bodies like MMS, PSA in the GOM and NCS respectively. There are several factors to be considered for selection of a mobile facility for performing a specific task safely and cost efficiently.

4.5.1 MOBILIZATION OF A MOBILE FACILITY

The transit time required to mobilizing a drilling rig to and at the field is considerable longer compared to the RLWI/WI -VESSEL. The following factors should be considered:

- Mobilization of the facility to the field;
  - Transit time from port to the field and tow requirements – a mobile dilling rig sometime will require means of towing, AHTS, to the field, in contrast to the vessel which will travel fast by own means of propulsion.
  - Weather condition under transit period – under worse sea state a drilling rig like a semi-submersible will have to seek refugee in a sheltered harbor and wait on weather.
- Mobilization/demobilization of intervention equipments on site;
  - Mobilization /rig up of well control package (BOP, LMRP, riser system) and making up of tool string for RIH/POOH depending on the number of runs while performing the task. Fill up of the riser system with fluid for establishing a barrier during operation.
  - Test requirements to be performed on site for well control package prior to carrying out intervention operations.
  - Demobilization/rig down of intervention equipment.

4.5.2 WEATHER/CLIMATIC CONDITION

Weather condition limits the operation window of a facility with respect to geographical location of the field where intervention operations have to be carried out. *A comparison can be made when operation in summer time has to be carried out, the significant wave height, H_s, in NCS range from 3-8m with wave peak period from 4-8sec while in West Africa coast there are long swells with H_s ranging from 7-10m with peak period from 10-14sec* ***(21)***. Small intervention facilities (RLWI/WI –VESSEL) motion characteristics are sensitive to waves induced motions compared to a drilling rig. This may result in high down time while waiting on weather (WoW). Wave induced motions to the drill rig relative to the sea bed should be compensated by a heave compensation system therefore calculated significant wave height for a mobile facility will limit the availability of a mobile facility thus increase its costs. Waves will induce translation motions in heave to a facility that will influence the position, velocity and acceleration of mobile floating facility relative to the seabed.

a) The **position** of a facility on the wave has influence in helicopter operations, effects vertical lifting operation as well as influences the necessary displacement length of heave compensation equipments.

Position of a facility at time, t: $z_h(t) = \frac{H}{2}\sin\omega_0\ \mathrm{t}$

Amplitude: $z_{h\max}(t) = \frac{H}{2}$

b) The **velocity** of a facility due to heave motion will affect helicopter operations, speed of lifting operations, and influence HPU capacity with respect to response to hydraulic flow needs in compensation equipment. Tool string vertical motions in the well would lead to pumping /piston-effect.

Velocity in heave of a facility at time, t: $\dot{z}_h(t) = \frac{H}{2}\omega_0\cos(\omega_0)\ \mathrm{t}$

Amplitude: $\dot{z}_{h\max}(t) = \frac{H}{2}\omega_0$

c) The **acceleration** induced by heave motions will influence vertical forces as well as fastening of cargo and equipment on deck. The acceleration will may influence the working ability of crew due to seasickness effect.

Acceleration: $\ddot{z}_h(t) = -\frac{H}{2}\omega_0^2 \sin(\omega_0)\,\mathrm{t}$

Amplitude: $\ddot{z}_{h\max}(t) = \frac{H}{2}\omega_0^2$ ***(13)***

Down time cost due to waiting on weather a relative smaller for a RLWI/WI VESSEL compared to a rig. This is due to the factor that the costs of hiring a small fit for purpose intervention facility is lower as indicated on figure 23 rig chase decision tree.

4.5.3 Comparison of drift costs/ charges per day for mobile facilities.

The charges/cost associated to perform a mobile drilling rig is higher than for a small intervention facility. The cost of hire per day is indicated in figure 22 as presented by Shlumberger in 2006, and currently the values for a drilling rig are ranging from drilling rigs are \$600,000 and \$700,000 per day ***(25)***.

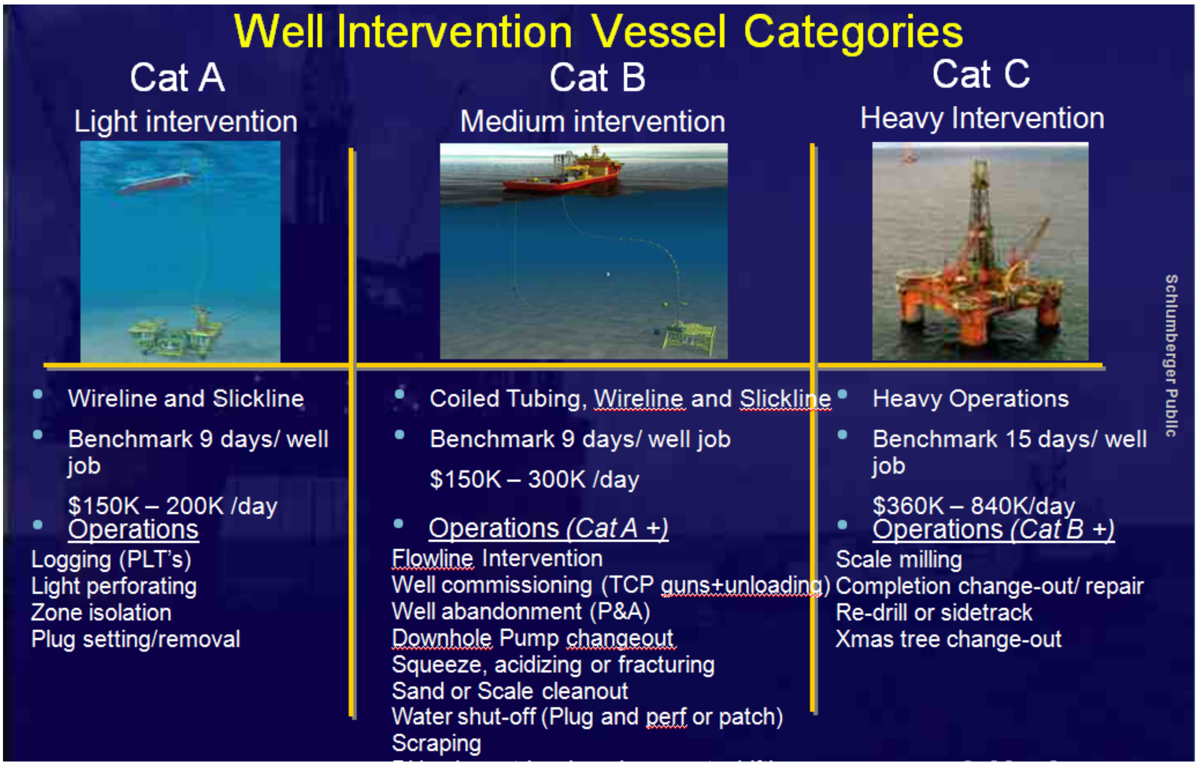

Figure 22. Subsea Well Intervention costs for different intervention levels in 2006.

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4.5.4 SCOPE OF INTERVENTION ACTIVITY TO BE PERFORMED.

It is seen clearly that specific well task and the scope of intervention activity would require a special type of a mobile facility. In P&A, the well status would set the bases for selection of a facility. Drilling rigs have no limitation with regard to weight handling capabilities compared to a small intervention facility where its MHT sets the limitation in weight taking into consideration pulling tubing section. Due to the handling capability for heavy lift for a drilling rig, a tubing hunger and whole of production liner tubing can be removed during P&A. It is cheaper to perform P&A by the use of a small intervention facility rather than using a drilling rig. In rig chase approach where a rig is moved from a plugged well to perform drilling activities to a new well serves time and costs. The small facility is easily mobilized to the site and casing strings cutting and recovery of the WH will be performed in a short time and saving costs. The evaluation of costs for achieving a WH cutting by drilling rig and small intervention facility for well status in CAT 1 done by IOSS is illustrated in figure 23.

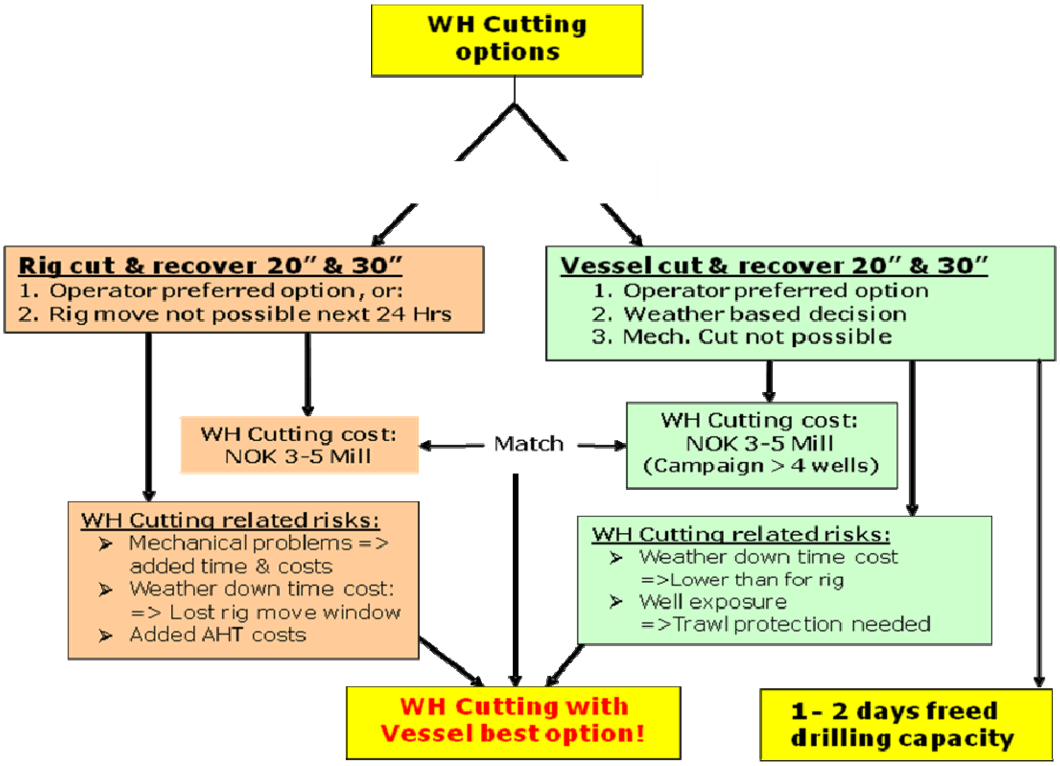

Figure 23. Rig chase decision tree (source IOSS)

4.5.5 SECTION MILLING OPERATION

Intervention activities by wireline or CT are limited in P&A operation taking into consideration section milling of a casing string or liner. These deployment methods can only perform packer and scale milling operations as well slot recovery by side tracking for CT with a whipstock. A tractor deployed by e-line can be anchored in the production tubing inner wall by friction and perform scale milling. The number of runs will depend on the length of affected area. Section milling of a casing string or production tubing cannot be performed by wireline or CT due to the weight requirement and means of cutting due to effect of buckling and control weight requirements. Section milling is done by drill rigs which have capability of providing tension load on the casing/ liner to be section milled, circulate cutting (steel debris) as well put enough weight on the milling assembly.

5.0 ESTABLISHMENT AND DESCRIPTION OF MOBILE FACILITY EQUIPMENT PACKAGE FOR WELL INTERVENTION.

Workover and Intervention control systems packages for subsea well intervention are established by identifying primary the scope of work/maintenance to be carried out down the well. The reasons for workover and well intervention are as follows;

- Production management of the well:
    - Maintain or Improve production levels (IOR),
    - Repair wellbore mechanical failures,
    - Terminate / suspend production.
- Well logging/survey – mapping status-data gathering and well diagnostics:
    - Flow characteristics ,
    - Geological data,
    - Fluids data.
- Altering the state of the well and/or well geometry:
    - Pro-actively(planned) or Re-actively (unplanned/failure),
    - Shut off unwanted water production,
    - Reservoir Stimulation / Fracturing,
    - Re-perforating the production intervals or establishing new intervals,
    - Open/closing valves,
    - Replacing parts,
    - Removing scale or wax precipitates,
    - Setting plugs,
    - Sand removal.

5.1 WELL WORKOVER AND INTERVENTION

Downhole remedial operations into the well may be conducted remotely from a production station through flowline (TFL methods). By pumping TFL conveyed tools maintenance tasks like change out of instruments and replacement of e.g. SCSSV can be accomplished (ISO 13628 Standard).

5.1.1 DEFINITION

The terms workover and intervention differ in several aspects, where workover implies full overhaul/recompletion of the well by the use of a full bore BOP, drilling riser and rig used for completion work in contrary to intervention commonly used to imply all kind of light vertical intervention activities (maintenance) done during a well production life. In light well intervention vertical operations take place in open water and inside through SSLS, the XT and the tubing by the use of small mobile facilities termed “small riserless intervention vessel”. Workover and well intervention activities are categories as follows:

Category A: Workover by the use of a rig with fullbore BOP and marine riser.
Category B: Medium well intervention, with smaller bore riser.
Category C: Light well intervention (LWI), wireline operations in open water and through SSLS as a well control package.

The categorization system is defined in different perspectives with respect to parties of interest in the oil industry ***(14)***.

Table 4. Categorization system for Workover and Well intervention activities.

<table>
<tr><th rowspan="2">PARTIES OF INTEREST</th><th colspan="4">CATEGORY</th></tr>
<tr><th>A
Light</th><th colspan="2">B
Medium</th><th>C
Heavy</th></tr>
<tr><td>Operator
(StaoilHydro)</td><td>Riseless (SSLIS)</td><td colspan="2">WOI Riser</td><td>Full bore BOP & Drilling Riser</td></tr>
<tr><td colspan="5"></td></tr>
<tr><td rowspan="2">Contractor
(Island Offshore)</td><td rowspan="2">Light
Riseless (SSLIS)</td><td>Medium</td><td>Heavy</td><td rowspan="2"></td></tr>
<tr><td>CT</td><td>TTRD</td></tr>
<tr><td colspan="5"></td></tr>
<tr><td rowspan="3">Standard
(ISO 13628)</td><td>Light</td><td colspan="2"></td><td>Heavy</td></tr>
<tr><td>SS Wireline</td><td colspan="2">Most Conventional</td><td></td></tr>
<tr><td>SS Reel Tools</td><td colspan="2"></td><td></td></tr>
</table>

5.1.2 DEPLOYMENT TECHNOLOGY

The type of intervention methodology and scope of work accomplished will depend on deployment technology. For well intervention categories A-Light and B- Medium, the most common deploying technology for a tool string (BHA) is by clickline, wireline and coiled tubing. The description and scope of work each technology can accomplish is defined as follows:

- Slickline deployment technology:
  - Monofilament wire used to mechanically convey tools into wellbore.
  - High tensile wire spooled on and off a powered drum (reel system)

  Scope of work performed by slickline is pulling only.
- Wireline deployment technology:
  - Multi-strand cable for mechanical conveyance of tools into wellbore, as well as provide an electrical / fiber optic communication path to the operator.
  - High tensile cable spooled on and off a powered drum.

  Scope of work performed by wireline = pulling and communication.
- Coiled Tubing deployment technology :
  - Rolled & Welded continuous length of steel tubing which is used to convey tools, provide communication path, as well as provide a fluid flow path.
  - Coiled tube spooled on and off a reel, utilizing an “Injector” system.
  - Tube can have integrated Wireline.

  Scope of work performed by CT = pulling, communication, pushing and pumping.

5.1.3 MAINTENANCE ON SEABED EQUIPMENTS

ISO 13628 Standard paragraph 8.7.3 “Seabed equipment maintenance”, defines the scope of work that can be done subsea on XT, WH, control modules, valves, manifold, template, flowlines and connections, riser bases and riser system. Generally the scope of intervention is done by module replacement conducted by deploying tools on pipework strings, wirelines and ROV, or manned intervention methods (wet divers). Further repairs may be carried out in-situ by ROTs, ROVs or accomplished by mono- or hyperbaric diving without recovery of equipments to the surface.

5.1.4 Common problems expected to be encountered during execution of intervention operations

Well control is a priority number one for accomplishment of successful and safe well intervention operation. Several safety aspects should be taken into consideration with regards to expected risks that may be encountered prior and during the operation which may raise liability issues to human, facilities, well and environment.

- Safety:
    - Hazardous working environment:
        - Personnel risk,
        - Movement (accelerations), Pressure (blowout and explosion), Weather (limiting availability), Heavy Lifts (falling objects).
- Risk of environmental release in case of lost of well control.
- Lack of close contact with intervention systems / tooling:
    - Loss of senses (direct) / feedback
    - HMI (Human Machine Interface) gap by taking into consideration the vertical distance from the vessel at water surface up to the well located 10,000ft subsea.
- Variable weather conditions, wind, waves and current may frequently limit the operation (vessel availability) by inducing translation motions (heave, sway and surge) and rotations (roll, yaw and pitch) on a vessel as illustrated in figure 24. The vertical motion, especially heave, speed and acceleration are critical for achieving a safe and successful operation with respect to lighter mobile facilities motion characteristics.

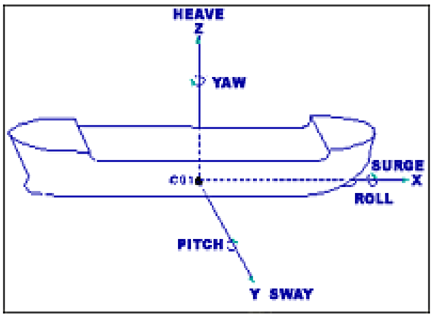

Figure 24. Six Degrees of Freedom of a vessel.

- Dynamic working relationship
    - Between a work platform (vessel) and wellhead (on seabed) may impose cyclic tensile forces on the wellhead as well as pumping effect inside the well.

5.2 Procedures and Line of Communication Prior to Initiation of Subsea Well Intervention.

Procedures for conducting well intervention activities should be clearly defined prior to execution of the activities down hole. ISO 13628 standards paragraph 8.7.2.3 requires prior preparation of procedures in advance of initiating any subsea maintenance operation. Work plan should be indicated and coordination with other concurrent field activities clearly defined, including the list of materials, equipments and services required for the specific operation should be in place.

The platform will hand over the well to mobile facility after the DP trial by the facility has been conducted with sufficient heading, and an ROV survey conducted before opening the hatches on subsea template. After the well has been handled over to the facility, the rig up procedure for well intervention will be carried out in accordance with the contractor's, and other alliances manual. The communication during LWI operations will be conducted as described in the figure 25.

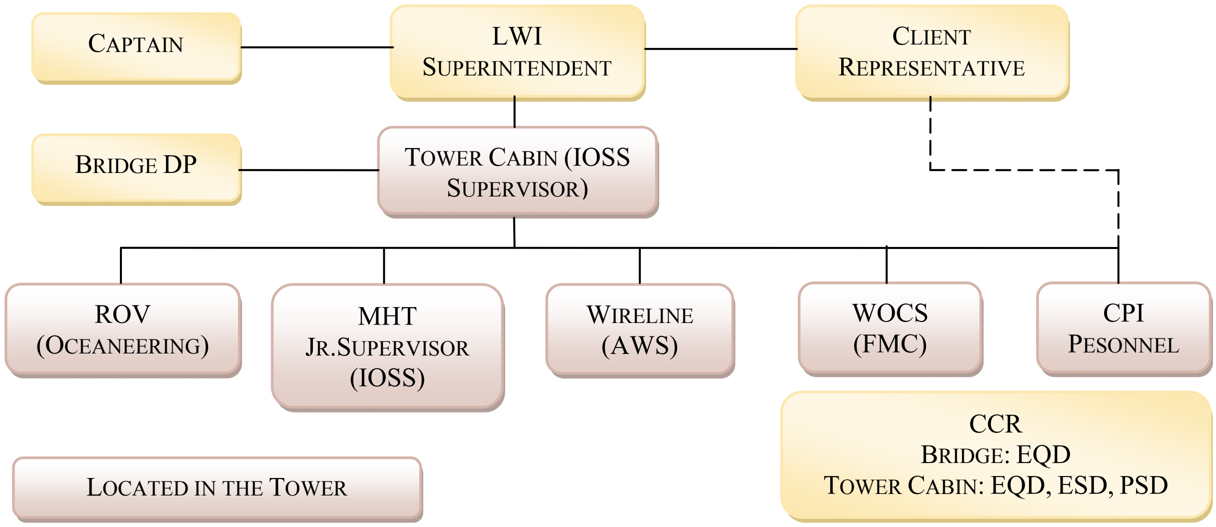

Figure 25. Line of communication during LWI operations (source Island Offshore).

5.3 DESCRIPTION OF SYSTEM COMPONENTS FOR RLWIS

The RLWI system enables wireline tooling to enter the well without using a rigid riser connection between the subsea production tree and the small mobile facility. The major benefit is reduced cost and operational time compared with use of a rig for interventions. The use of a mono-hull vessel service saves time since no riser needs to be installed and can move between oil fields much faster than a traditional intervention rig. Further, due to the fact that both the vessel and equipment costs are less, makes the RLWI service preferable for Light Well Intervention operations.

FMC has currently two types of RLWI systems. The first generation RLWI Mark I system and the RLWI Mark II system are designed according to the marked requirements for a next generation light well intervention system.

RLWI-VESSELs are mostly equipped with the existing system for intervention termed Mark I. The WI- VESSEL Island Constructor will be equipped with the new generation of subsea well control package for intervention Mark II developed by FMC ***(20)***.

5.3.1 SUBSEA INTERVENTION STACK CONFIGURATION

The conventional type of subsea intervention stack Mark I comprises of the following;

- PCH: has three WBE:
    - Grease Injection tubes,
    - A single and dual stuffing box, with independent auto grease supply,
    - Ball check valve.
- The ULP has one wire line shear seal ram (WSSR).
- The LIP has three WBE:
    - 7’’ gate valve Upper Production Valve UPIV,
    - 7’’ gate valve Lower Production Valve LPIV,
    - 7’’ shear seal ram, SSR.
- Stack is pressure rated to 10.000 psi:
    - Test frequency according to RLWI Operation manual,

- Test criteria for the well and lubricator stack is defined by StatoilHydro Well Program.

5.3.2 PROCEDURE FOR RUNNING BHA FOR WIRELINE (RLWI).

Rig up procedure:
- Removal of debris cover.
- Removal of tree cap.
- Run pressure test stack (LLP/LIP).
- Run upper lubricator package (ULP).
- Rig up wire line, prepare and run PCH.
  - Tool string position,
  - Run tool string in tandem with PCH,
  - Remove ULP debris-cover by ROV,
  - Lower tool string down to ULP/PCH connector (ROV pilot),
  - ROV guide tool string with C-ring – guide/entering cone,
  - Open PCH – connector and remove guide/entering cone by ROV,
  - Run tool string and deploy PCH,
  - Land PCH – close connector,
  - Release PCHRT and retrieve to surface.
- Flushing of lubricator opening up to well: FMC.
- Well operations and testing of XT-valves: Statoil well program.
- Retrieval and rerun of PCH in between wireline run.
- Flushing of lubricator – abandon XT; FMC:
  - Retrieve ULP.
  - Pull stack (LLP/LIP).
  - Run tree cap, TC.
  - Install debris-cover, close hatch.
  - ROV-survey and well handover. Statoil instruction.

Mark II show in figure 26 is a new generation of Mark I SLIS.

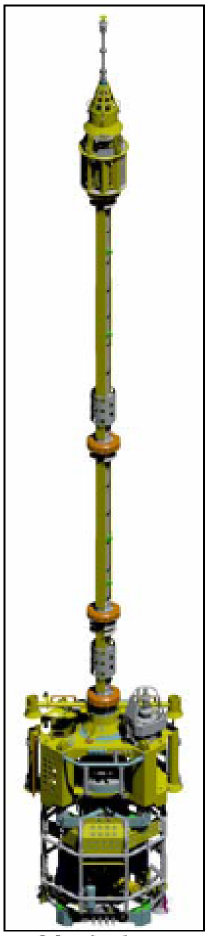

Figure 26. RLWIS Mark II

5.3.3 BARRIER PHILOSOPHY / WELL STATUS

All wire-line operations shall be performed with 2 barrier elements to prevent uncontrolled blow out from the well to its surroundings: one active barrier and one passive barrier.
- Consent IOM/IOSS and Alliance partners: shall assist oil operating company with compilation of all relevant documentation and data received for application of regulatory consents or permit required to conduct LWI – operations.
- LWI Project manual,
- Well Program: Unique LWI Well Program describing step by step activities.

5.4 STATE OF THE ART IN TECHNOLOGY ADVANCEMENT

Due to technology advancement the new state of the art fit for purpose build facilities like Island Contractor is planned to be equipped with a new state of the art well intervention package comprising CT and small bore rigid riser system to increase the scope of work done by light well intervention mobile facilities. The notations WI-VESSEL and RLWI-VESSEL are used with Island Offshore AS to indicate an intervention mobile facilities equipped with small bore rigid riser system and riserless system respectively.

5.4.1 General

Island Constructor as a Floating Well Intervention facility (mono hull vessel) shall perform the following operations (more concrete of the facility specification in attachment 5):

- Wire-line services with the use of SSLS
- Sub sea construction and equipment installation
- Structural prepared for CT operations with rigid WI riser system
- P&A work

- The topside equipment and systems installed above the WI-VSSEL's main deck and moon pool area, including related equipment and systems for special reasons located below main deck. The topside is modularized including the derrick structure and dedicated area allocated for alternative services. The facility is equipped with utilities for CT operations with rigid riser and deck lay-put and MHT adapted to such operations.
- Scope of work and services: Perform well intervention services for maintenance and IOR for existing subsea oil/gas field. DP-vessel designed constructed, equipped and certified for world wide operations, except US inland waters, Baltic Sea, Black Sea and similar areas with special restrictions and requirements.
- Prime area of operations: North Sea at depth from 70-800 meters and well depth of up to 7500 m measured depth with pressure control equipment rated to 690 bar working pressure and main winch capacity for water depth down to 1000 m.
- Permanent installed ROV system consisting of 2 work ROVs.
- Facilities to assist in template installation work and seabed construction, installation and maintenance work.
- Well intervention services performed by using a subsea lubricator system and in addition the vessel is designed to perform CT operations with rigid riser system.
- Basic design criteria and vessels main particulars ULSTEIN SX121
- Specific requirements:
  The requirements are subdivided into the following categories:
  - Flag state and Registration,
  - Statutory requirements,
  - Classification Society Rules,
  - Certificates,
  - Applicable Codes and Standards.
- General services and operations: The WI-Vessel accommodates a full wire-line and electric logging package and CT operation. The Topside is equipped with adequate material-handling and guiding-system such that it provides a high level of safety and efficient handling of all equipment during rig-up/mobilization throughout operations, and during rig-down/demobilization. For achievement of safe working environment it is recommended that all piping and cabling be permanent installed. For safety reasons equipments are arranged to avoid working over open sea and the use of riding-belts during routine operations.

1. SSLS operations by the use of slickline and E-line:

- Running/retrieving DSV,
- Running/retrieving plugs and bridge plug

- Running/retrieving wire-line set pressure and temperature gauges,
- Operating sliding sleeves,
- Slickline caliper surveys,
- Locking open TR Safety Valves (TRSSSV),
- Wire-line toolstring fishing,
- Slickline logging,
- Perforation operations,
- Power Truck Advance to deploy mechanical tools and electrical pyrotechnical.

2. CT operations through Rigid Riser, services:

- Retrieve crown plug by wire-line,
- Pay out coil to desired depth and start pumping,
- Well cleaning and sand jetting,
- Milling, scale removal,
- Gas lift,
- Acidizing and simulation,
- Squeeze jobs,
- Setting of packers and cement plugs,
- Displacement of fluids,
- Fishing,

5.4.2 KILL SYSTEM WITH MANIFOLD AND ASSOCIATED EQUIPMENT

Mixing system for adding dry/liquid chemicals into kill fluid is installed on the mezzaniene deck aft (3x20m^3 tanks for mixing purpose) and in addition a 500 m^3 tank capacity for mud/brine is located below deck.
During CT operation with riser, the kill pumps take suction from mud system and pump brine/sea water through CT. The return fluid in the riser annulus is led through flow tree and choke – MGS system. The kill system includes the following equipments:

- 2 hose-reel and storage tank for killing fluid
- 2 well service capacity pumps at 607 (t) min, 690 bar

5.4.3 THE MUD SYSTEM

The system is module built with a capacity of treating 40 cum/hr and consists of:

- MGS – capacity 2MMscuf/d
- Degasser, mixing hopper, shale shaker, Trip tank, sand trap, vacuum degasser tank, active tank, mixing tank, agitator, valves inter-connecting pipes and wire, mixing and transfer pump, local and remote control panels.
- The inlet line to the MGS is hooked up from the choke manifold and the gas outlet is connected to the flare boom.
- In case of excessive oil return from the well, an oil/water separator is required. The oil may be stored onboard if permitted, or flared according to PSA/UKCS regulations.
  For CT operation a flare boom of accepted capacity is required and shall be designed according to NORSOK specifications. It shall be located aft and be swang outwards to sea while burning gas/oil with vessel heading against wind.

5.5 RISERLESS WELL INTERVENTION CONTROL SYSTEM (MARK II)

As mentioned earlier, the new vessel will be equipped with a new generation wireline control package termed Mark II. The system shall enable wire-line tools to access the well in a safe and controlled operation for personnel and environment. The system is designed for a suitable mono-hull vessel and run in 2 guideline wires assisted by ROV. The complete package is designed in three pieces and remains connected to the wellhead for the duration of operation. System specification for RLWI Mark II is provided in attachment 6.
The subsea packages comprises of:

- Well Control Package (WCP) including safety valves and safety head,
- Lubricator Section (LS) including the lubricator pipe joint and a 7'/10'' ball valve capable of cutting wire-line,
- Seal Section (SS) provides a dynamic seal between sea and the pressure inside the LS (well).

The new operation IWOCS system has been dramatically reduced in complexity and number of units. The traditional WOCS container with integrated HPU and operator room has been replaced by distributed HPU's on the subsea equipment and the operator room integrated with the vessel's control room. As a result of the distributed HPU's and the grease injection system subsea, the umbilical has been reduced dramatically compared to the existing system, Mark I. *The biggest change from Mark I to Mark II RLWI system is the control system architecture. The Mark I control system is a combination of electro-hydraulic and direct hydraulic control systems with a surface HPU, surface chemical injection and grease injection system, using a large diameter multi-bore umbilical.*
The Mark II control system has been developed around the premise of eliminating the large cumbersome umbilical seen in figure 27, both to eliminate the heave-compensation bending issues and to enable much deeper water depth operations. Increased umbilical length often leads to larger diameter hoses in the umbilical between the surface HPU and subsea hardware to fend off the effects of fluid pressure loss and increased reaction time. An all-electric power umbilical similar to what is used for ROVs today is implemented in the system. However, the elimination of the hydraulic hoses from the umbilical requires that the HPUs, CIUs, and GIUs are moved from the topside facilities and implemented in the subsea equipment ***(20).***

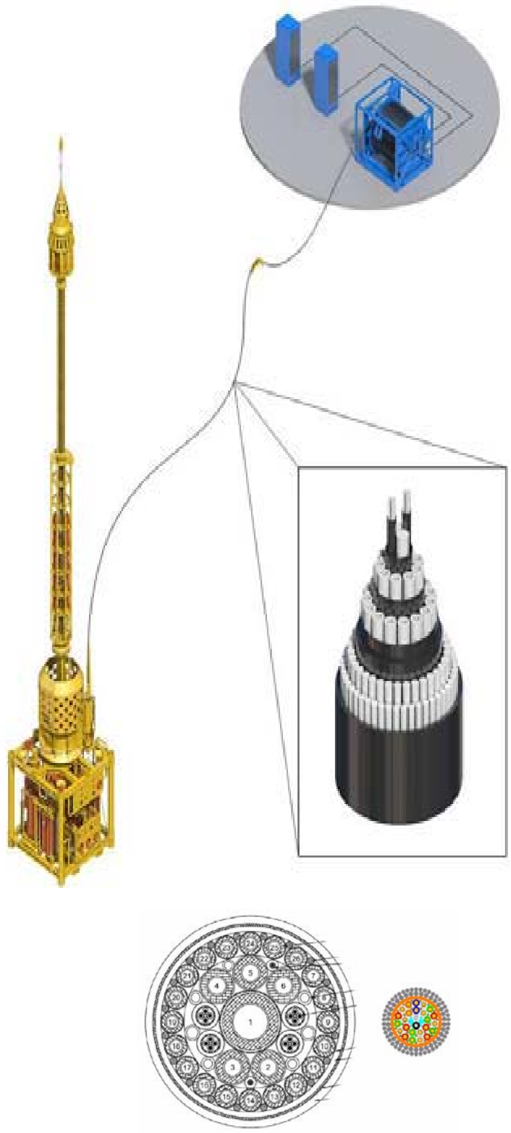

Figure 27. Mark II RLWIS and the comparison of umbilical size for Mark I (left) and Mark II, ROV-type electric umbilical, (right).

5.6 COILED TUBING OPERATION

For simplicity the description of features designed for CT operation has been divided into two parts making the well control package located subsea and topside including all equipments providing rotational motions, compensation, suspension and control and management of CT while RIH/POOH. For a clear understanding of system layout and data specification refer to attachment 7 and 8.

5.6.1 DESIGN DATA/SPECIFICATION PER SYSTEM TOPSIDE

5.6.1.1 TOP TENSION SYSTEM

The tension system provides tension to CT Frame (CTF), Gimbal support (GSF) frame with Gimbal, swivel and compensator for the relative motion of the vessel.

5.6.1.2 RISER TENSION SYSTEM

Provides positive tension to the well intervention riser, and compensate for relative motion between riser and the vessel.

5.6.1.3 IRON ROUGH NECK (MAKE AND BRAKE TOOL)

The iron rough neck is required for assembly of the riser system.

5.6.1.4 FALSE-ROTARY TABLE

A false rotary table with a gimballed insert 37 ½'' master bushing is required for hanging of the riser.

5.6.1.5 RISER CENTRALIZING ARMS

Installed in the lower part of the moon-pool to centralize/stabilize the riser string when required (Remotely controlled from control station on main deck).

5.6.1.6 CT FRAME (STRUCTURAL)

Provide self containing means for handling the CT Injector head, Tool String and Pressure Control equipment within the Module Handing Towel of the WIU.

5.6.1.7 CT INJECTOR HEAD

Used to convey the CT string for RIH and POOH of the well. It is equipped with a large radius gooseneck determine to minimize fatigue on tubing. The capacity of traction system for the injector head:

- Continues pull – 80,000 lbs
- Intermittent pull – 110,000 lbs
- Snubbing capacity – 40,000 lbs

5.6.1.8 Dual Stripper

The unit is utilized for pack-off on CT as it stripped in and out of the well at pressures up to 1000 psi. The packer provides preliminary barrier when energized. 2 door side door stripper comprises of a top element pack-off under normal circumstances, and in case of failure the lower element packer may be packed-off to maintain seal integrity.

5.6.1.9 Surface CT BOP

- The BOP Ram shall provide a means of shearing CT. The ram shall also, in conjunction with a surface tree valve, provide two means of sealing.
- Shear seal ram shall provide a gas tight seal.

5.6.1.10 CT Power pack

Shall provide full operational power to all equipments within CT system and a local control shall be provided for critical functions.

5.6.1.11 CT-Reel

- Provide storage of CT string
- Capacity for at least 20,000 feet of 2-3/8 CT with reel core maximized to minimize fatigue.
- The unit shall have a life equivalent to 6 interventions each with 4 days in hole time.

5.6.1.12 Surface Flow Tree

- The SFT assemblies shall be designed for easy handling and to mitigate the effects of riser motion.
- Preferred valve type – a remote hydraulic operated metal-to-metal sealing gate. Operated under full differential well bore pressure and across the upper and lower temperature range.
- Master valve is Fail-as-is design (hydraulic close/open) and wing valves fail safe close (bi-directional sealing capability).

5.6.1.13 CT Cursor Frame with Gimbal

- GSF acts as a support for CTF and is connected to Top Tension System and taking the vertical loads from the CTF.
- Gimbal installed at the upper part of GSF ensures free rotation of riser in storm hang off mode. Gimbal suspends riser in its full length and allows at least 10deg pendulum angle. It shall be equipped with a remote controlled riser centralizer keeping the riser vertical when necessary.

5.6.2 DESIGN DATA/SPECIFICATION FOR SYSTEM SUBSEA

5.6.2.1 WCP/EDP INCLUDING RETAINER VALVE (RV).

The WCP is the same as for RWLI MK II system made up of LLP and a RU module. WCP and EDP based on 7'/16'' bore. The RV with Bi-directional sealing capability is operated through control modules already in place on WCP and LLP.

5.6.2.2 LOWER TAPPER STRESS JOINT

The Joint provides the riser system with a transitive zone of stiffness intermediate to the subsea tree and riser. Efficiently reduces highly localized stresses, thereby increasing fatigue life and improving operation envelop of the system. The joint minimizes as well transfer of riser loads into the XT and Wellhead.

5.6.2.3 RISER WEAK LINK

Designed to break under specified loads (tension) due to lock-up of Riser or Top tension System and shall not break in event of losses of station keeping.

5.6.2.4 HIGH SET LUBRICATOR VALVE

HSL designed to isolate the reservoir from environment when deploying long wire-line/CT tool string. The valve is safe fail as is designed (bi-directional sealing) and remote operated.

5.6.2.5 RISER SYSTEM

The design, manufacturing and operation of a riser system is in accordance with ISO 13628-7 standard. The designed for installed equipments is for a 20 year life time and 10 years life span for Riser Joint with appropriate maintenance and 5 years life with target service (accumulated operation). Risk Analysis ad Shut down/ disconnect philosophy are tools used to define the time requirement is with respect to EQD.

The riser system should be able to satisfy the following under CT operation:

- The integrity of Subsea WH, XT, re-entry connector/cross over are not compromised due to applied pressure and bending loads under normal operation or extreme and relevant accidental conditions.
- The system shall include load limiting system to avoid any compromise to components below WCP in case of unplanned/accidental compensator failure event such as tensioner/compensator failure or vessel drive off/drift off.
- HC release from the Well/ Riser should be avoided under operation (containment) and facilitate flushing/cleaning of HC release under normal operation.
- Enable full bore vertical access to the TH and Down Hole Completion for intervention (wireline, e-line and CT deployed tooling). This includes as well full bore access for smooth passage of tools (unobstructed passage of drift tools) during RIH/POOH.
- Provide safe withdraw from the well under safe response speed, disconnection angle under emergency and accommodate effective HC management.
- Provide pressure integrity barrier under applied bending and tension loads on riser during flow back, injection testing and down hole intervention operations.
    - Incorporate suitable means for monitoring pressure.

- Incorporate suitable means for flushing HC from Riser.
- Be a conduit for transmission of all expected types of well bore fluids.

- Incorporate an appropriate riser monitoring and telemetry system for measuring riser stresses and estimation of loads imposed to WH thus optimizing the operation envelop and vessel heading under given environmental conditions.
- Ensure adequate protection of umbilicals at top side interface and route to avoid trapping between reciprocating parts during either installation/retrieval or operation.

5.6.2.6 SWIVEL

The swivel Installed at the upper end of the Riser String below the HSLV and permit 360deg rotation to allow vessel weather vaning. Its structural designed copes with the Riser Systems worst-case pressure, bending, tensile loading and capable of rotation under these conditions.

5.6.2.7 MODULE HANDLING SYSTEM (MHS)

Fully equipped with a Module Handling Tower, an integrated Moon-Pool Door System as well as a deck mounted Horizontal Skidding System. *The MHS requires modification to perform CT operations i.e. increase height to accommodate CT injector frame and GSF.*

5.6.2.8 WIRE-LINE EQUIPMENT

Same as installed in Island Constructor RLWI modus with addition of the following:

- Wire-line BOP for standard rig up – to be rigged up in CT rig-up frame
- Wire-line lubricator for standard surface rig up – to be rigged up in CT rig-up frame
- GIH/Stuffing box for standard rig-up – to be rigged up in CT rig-up frame
- BOP control panel – may be built in, remote operated and hard pipe from below deck.
- Pressure test pump – may be built in remote operated and hard pipe from below deck
- Additional BHA tool package for extension of Scope of Work (SOW) to fishing of wire.

5.6.2.9 PROCESS SYSTEM INCLUDING FLARE

Possible means for handling upstream flushing water contaminated with HC during CT operations are required. The system should be able to separate water from HC and flare the gas/oil (capable to handle 5-50% of oil content in water). High pressure flushing operation leads to flushing fluid contamination with particles requiring further treatment through the shake/sand trap.

Island Constructor will be equipped with a brine/gas/water/gas recovery /separation system. The basic design for recovery of circulated fluid as seen in figure 28 is in conjunction with CT operations. Several different scenarios are taken into consideration in the design bases with regards to the Well status (live HC producing well, shut in well for intervention/ abandonment). Further more the design parameters are dependent on the treatment of return fluids from the well during CT operation. Under cleaning operation, the fluid used for Jet flushing will contain water, oil and sand particles requiring separation and perhaps there would be a necessity of total recovery of the circulation fluid.

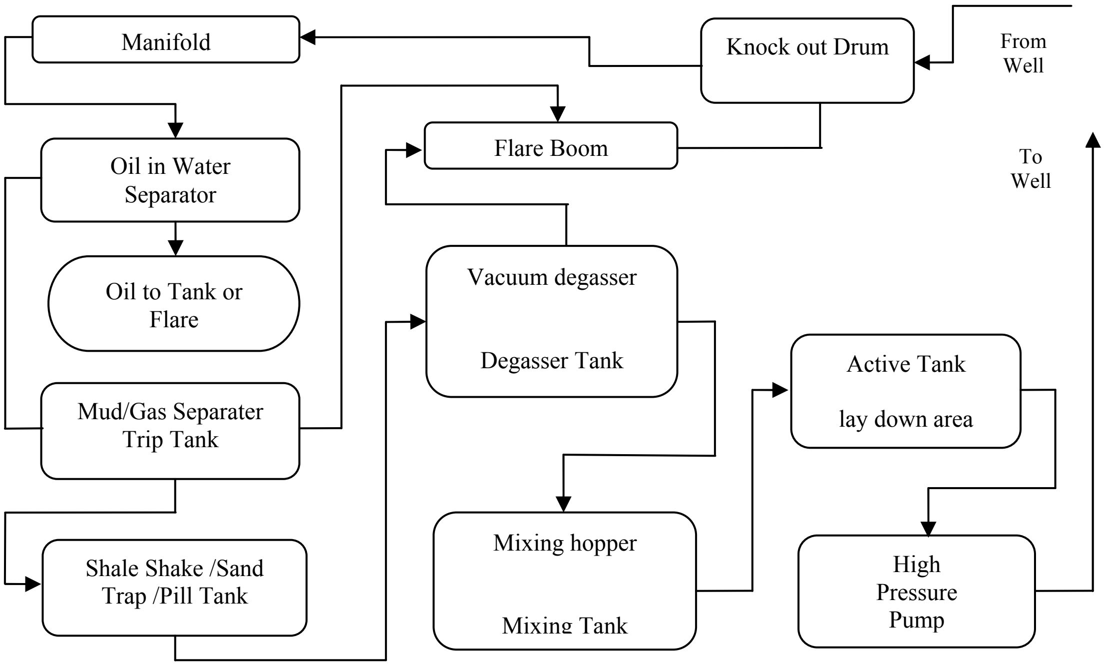

Figure 28. The system designed for treatment of circulation fluid contaminations during jet flushing operation.

5.6.3 BARRIER PHILOSOPHY

- Stringent requirement shall be followed and application of NORSOK D-010
- Control system will produce alarm for PSD/ESD/EQD and the operator will trigger PSD/ESD/EQD from station depending on predefined conditions.
- The Contractor shall identify the Primary and Secondary Barriers for each riser mode in each planned well operation. That will include an assessment of the impact of potential system configurations, conditions, and operations as well as shutdown scenarios.
- Two independent mechanical barriers shall be in-place prior to removal of subsea equipment (e.g. EDP). The sea barriers may be a combination of active and passive barriers.
- During connected operations, one primary barrier shall be in place and secondary shall be available and ready for activation which is independent to the primary. At least one of the barriers shall be mechanical where the primary may be a temporary barrier.
- SCSSV may be used as a barrier in controlled shut-down events when successfully tested and it shall not be considered a barrier when well system is exposed to an unplanned event such as EQD, riser failure, etc.
- In case of shearing operations, shear ram should be capable of sealing after shearing tool string.
- Test for mechanical and active barriers shall be conducted on installation and prior to reservoir fluid exposure
- Water is preferred as test fluid, however once reservoir fluids have been produced to the surface flushing by glycol is required to avoid hydrate formation.
- Test shall include a low pressure test of 200 – 300 psi for 5 min before proceeding to the full-pressure test. All tests shall be recorded on appropriate chart. Prior to pressure testing, area shall be isolated and personnel evacuated.

5.7 LIMITATION WITH RESPECT TO AVAILABLE DECK SPACE

The deck layout on Island constructor is limited due to scarcity of space to accommodate a cement processing module. For P&A operation it would be necessary to hire a cement mixer module or mixing facilities from other service providers for cementing operation. The flare system currently is still and discussion on whether it has to be installed onboard the facility and probably will not be installed for the same reason of deck space and other factors related to accessibly during maintenance work. It is known that congestion of equipments on small deck area may become an obstruction for performing inspection work as well difficulties in carrying out maintenance.

6.0 CONCLUSION AND RECOMMENDATIONS

1. Based on the technology available today it is possible to utilize intervention facilities for permanent plugging and abandonment of subsea wells and WH removal campaign. Some of the technical issues have been analyzed and concluded to suggest the main conclusion.

- Methods for killing the well in a case of a live well, have became common practice therefore it do not pose any challenge on gaining well control. The industry has gain more knowledge and experience with respect to deployment of tools downhole by wireline and CT through open water and well control system (WCP, EDP, SLIS and WOICS) which is well known and proven technology. Technology advancement has accelerated lately and led to the development of fit for purpose and new state of the art systems which are more reliable like new generation of Mk II SLIS and small bore riser systems.

- The production tubing has no economical value at the end of production life cycle of the well; therefore it may be plugged and left in place considering that there are no requirements of recovery embedded by regulatory bodies and still when removed may require costly treatment before disposal.

- The possibility of setting expandable mechanical plugs through tubing by wireline justifies that permanent barrier can be established extending up to a 13 3/8"casing. The BOP on WCP is designed with a drift diameter that can accommodate a toolstring not exceeding 7" OD. Access between casing strings can be established by oriented explosive charges, and cement slurry pumped through the production tubing. Perforating gun design, deployment technology and detonation methods have been optimized, though still it is necessary to account for risks involved by handling explosives with care. Tractors which are cost effective wireline conveyance tools for toolstring in horizontal wells can be used to deploy, anchor electric cutting tool and perform production tubing cutting without adding HSE risks. This wireline cutting technique is advantageous compared to the conventional wireline operation by use of explosives.

2. Economically the use of small intervention facilities is a viable solution:

P&A can be performed by utilizing a small intervention facility since the end product is dictated by advancement of engineering solution available and equipment availability. The rig approach involves the application of full workover equipments as for completion work with straightforward known results and in contrary *increases the operation cost due to time of mobilization/demobilization*. Rig-less method by wireline and CT approach will be less expensive *due to reduction in time of mobilization* and it is faster to RIH and POOH when setting plugs. Mechanical malfunction during wireline operation may lead to fishing operations, increase in downtime and hence a slight cost overrun for the P&A operation.

Based on the arguments provided and the techniques associated with plug setting downhole, it is recommended that P&A should be preformed by WI/RLWI VESSELs as a complementary solution to the use of drilling rig.

7.0 RECOMMENDATION FOR FURTHER RESEARCH WORK

1. Weather and dynamic load acceleration.

The main challenge is associated with limitation on small facilities MHT and derrick system rated carrying capacity which is governed by the location water depth and weather condition. Basically depth determines the connection length of riser systems and wave induced dynamic load coupled to the weight of WCP, EDP for intervention activities. So far the design of the riser system for Island Constructor is limited to 600m though the crane system has a limited lifting capacity of up to 1000m. Dynamic behavior of small facilities should further be research to increase the operation window for deeper water of above 1000m.

2. Improvement of exciting capabilities beyond 1000m.

Seen from this aspect, the only viable solution to perform P&A for wells located deeper that 600m is by the use of ROV deployed tools coupled with long hoses (umbilical) for circulation of fluid into and from the well. Special crossover tools with double packer have to be designed taking into consideration the establishment of sufficient well control barrier as required by the authority prior to initiation of severing the casing strings susceptible of containing SCP.

3. Standardization of WH profile

The variation of WH profiles and dimension apart from H-4 WH system, poses another challenge due to the fact that the profile has not been standardized. For that reason, it would be necessary to carry onboard different sizes of WH to WCP interface or crossover adapters to provide a pressure contain element between them before control of SCP in annuli spaces is performed.

4. Improvement of downhole technology for light small facility type of operations.

It will be wise to carry out an extensive research on cement and steel casing bonding factor since, over time the reservoir pressure and temperature will build up. The thermal stresses induced on the steel material may become lead to debonding of the cement sheath and casing forming migrating routes for reservoir fluids. The best solution will be to squeeze cement to the rock below the production casing, where cement seepage into the bedrock providing a permanent and solid bonding blocking the possibility of HC migration below the production tubing shoe. This can be accomplished by first window milling of a section of the production tubing without recovery to the surface of cuttings. Unfortunately per today, wireline and CT operation are limited to scale, and plug million operations, therefore a study should be carried out to enhance section milling by wireline and CT.

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ATTACHMENTS

Attachment 1

Meeting with PSA – Mr. Stein A. Tonning on rules and regulations regarding construction of mobile offshore facilities on 06th February 2009, Stavanger

Cases to be discussed:

1. Standards, NORSOK Standard and Petroleum Act.
2. Shut in well categorization system applied by PSA:
    - Oil and Gas UK categorization of shut in wells.
3. Application for Acknowledgment of Compliance for small facilities (Samsvarsuttalelse – SUT):
    - NCA and IOSS, expansion of activities in decommissioning.
4. Experience:
    - Requirement on cutting casing strings
        - Use of explosives
        - Jet cutting

Meeting with NCA – Mr. Per Lund on Plugging and Abandonment on 06th March 2009, Stavanger

Cases to be discussed:

1.0 Well shut in

- 1.1 Killing the well
- 1.2 Plug setting

2.0 Evaluation, discussion and recommendation on "safe" methods for handling trapped gas and hydrocarbons under pressure in annuli spaces.

- 2.1 Technical methods for containing trapped gas in annular space during bleed off.
- 2.2 Technical methods for containing and circulating trapped hydrocarbon liquid in annular spaces during bleed off.

3.0 Wellhead cutting and lifting

- 3.1 Wellbore clean out
- 3.2 Production tubing/string removal in open water
- 3.3 Jet cutting
- 3.4 Wellhead pick up

Meeting with Island Offshore – Mr. Bernt Gramstand on 11th March 2009 on Plugging and Abandonment, Stavanger

Cases to be discussed:

1. Re-entry of the well category 2
    a. Wireline
        i. Subsea Intervention Lubricator System
        ii. Workover tools
            1. Setting of bridge plugs
            2. Establishment of bleed off SCP and circulation path
            3. Circulation of cement
    b. Coil tubing
        i. Rig up & down of workover equipments
        ii. Circulation system
    c. Recovery of wellhead

2. Re-entry of well category 3.
    a. Killing the well
    b. Coil tubing
        i. Rig up & down of workover equipments
        ii. Establishment of bleed off SCP and circulation path
        iii. Cleaning up
        iv. Setting of mechanical and cement plugs
        v. Storage of hydrocarbon
    c. Recovery of wellhead

Meeting with Island Offshore – Mr. Robert Friedberg on Comparison of Registration Requirements for an installation vs a Vessel on 27th March 2009, Stavanger

Cases to be discussed:

1. What exactly are the key points regarding regulations that differential an installation from a vessel

2. Which SUT requirements are considered necessary when a vessel is converted into an installation?

3. For new build fit for purpose LWI units, are there any kinds of SUT exemptions provided by the NPA?

    - Ships hull and strength of construction material
    - Ship stability and ballast system
    - Machinery and emergency electrical power supply
    - Topside equipments including systems for well control
    - Anchorage , mooring and positioning with respect to DP class

4. Safety requirements

    - Navigation systems
    - Manning of LWI units
    - Rescue equipments and life saving appliances (types of life boat)
    - Minimum requirements for corridor and ladder
    - Detection (fire and gas detectors) and protection systems

Attachment 2

Interview with Mr. Robert Friedberg at Island Offshore, 27th March 2009, Stavanger.

The key points regarding construction and registration of an installation and a vessel for offshore activities is mainly associated with the regulations set by regulatory authorities, NMD which is the Norwegian flag state, Norwegian Petroleum Safety Authority PSA, International Maritime Organization IMO and classification societies like DNV, and guidelines stipulated in offshore standards like NORSOK in the NCS.

According to Mr. Robert the main few key elements are based on the stringent requirements on documentation for an installation in contrast to a vessel. The following factors where discussed with regards to the construction of an installation with respect to a vessel:

1. Factors related to construction of an installation vs a vessel:

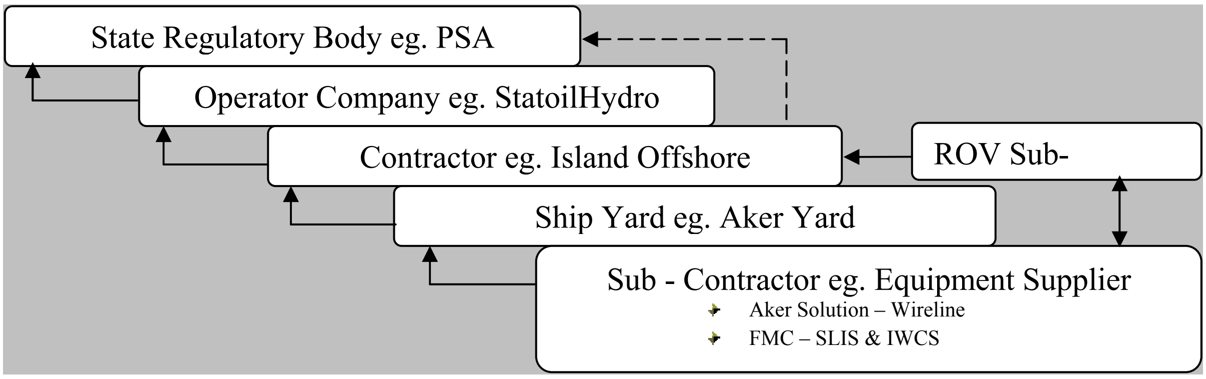
   - Size of the organization onshore for project follow up and a team required to plan the project is more substantial for a mobile offshore unit than for a vessel. There would be a minimum of 5 people working for preparing documentation for an installation and the project follow up during construction will require several experts in contrast to a vessel where chief engineer and captain will be satisfactory to make follow up during construction at shipyard. In most cases yards will provide necessary certificates for a vessel that would be required for NMD compliancy, in contrast for an installation where Ptil requires full documentation.

   - A contractor have to abide to the (i) operator specific requirements where the size of documentation provided by an operating company will require a lot time to go through for compliance, and (ii) a installation compliancy to the SUT (safety case) requirements posed by PSA.

   - There is a strong documentation requirement set by PSA for traceability of equipments and components in a system such that in case of failure that could ease investigation by tracing back on its origin. Other factors concerns:
     (i) Evaluation for criticality analysis involving frequency of failure and consequences.
     (ii) Contingency plan and redundancy with respect to consequences and safety risks associated with system failure to personnel, environment and property.

2. Factors related to operation of an installation vs a vessel:
   - Stricter regulation for training and certification of crew and work schedules. Additional cost in manning of an installation due to the work rotation of 2 weeks on and 4 weeks off in contrast to that of a vessel where crew works in a rotation of 4 weeks on and 4 weeks off.
   - Working environment with respect to ergonomics, noise and vibration reduction, and lighting condition for safety of crew.

The construction costs for a mobile offshore unit would be considerably higher than that of a vessel. PSA requirements leads to additional costs, where we may find that equipment manufacturers are forced to deviate from original standard specifications for production of specific equipment in order to suit specific requirements for an installation. He gave an example for ergonomics where it is required to have means of adjusting a DP consol height so that it would be comfortable for DP controller. Since such kind of adjustable consol may not be available on the market, it may require a specific order to be pressed thus increasing additional costs. Further, the authority requires standard size of rooms in living quarters, recreation rooms and daylight illumination thereby increasing dimensions for windows.



Flow diagram illustrating the business hierarch in the oil industry

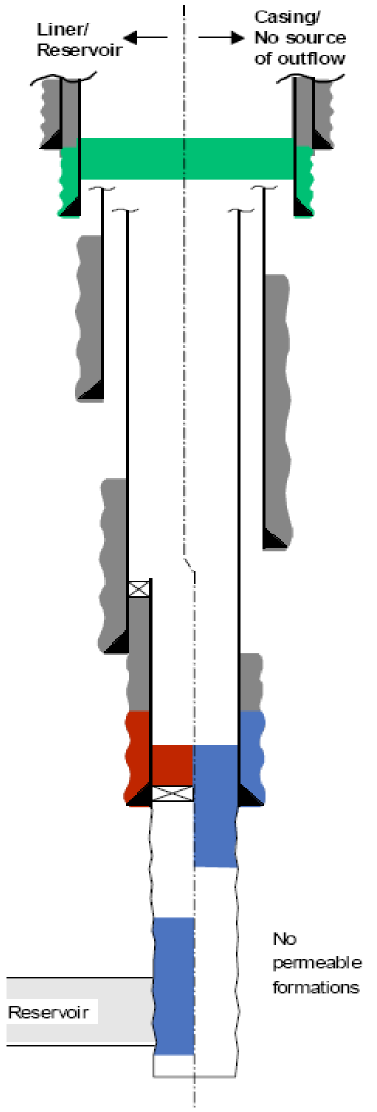
There is a need for a cost benefit consideration to avoid unreasonable costs to rules application, but PSA requires full documentation for compensating measures to deviation acceptance.

Further, a question was raised on whether it is possible and would be cost beneficial to convert an operating vessel like an AHTS to a RLWI installation.

He commented that, SUT requirements make it difficult to convert a normal operating vessel (supply boat) to a fit for purpose LWI installation due to the expected costs. It is worth constructing a new vessel with full SUT requirements since reconstructing and fitting an old vessel with topside well control system and equipments would be extremely expensive. He said PSA will accept a vessel build with NMD certificates, but it should comply with the SUT requirements to work in petroleum activities. Island Offshore has built LWI units with clean design (DNV) and these facilities comply with SUT requirements.

Attachment 3

9.8.3 Permanent abandonment - Open hole



Well barrier elements	See Table	Comments
Primary well barrier		
1. Cement plug	24	Open hole.
or, ("**primary well barrier, last open hole"**):		
1. Casing cement	22	
2. Cement plug	24	Transition plug across casing shoe
Secondary well barrier, reservoir		
1. Casing cement	22	
2. Cement plug	24	Cased hole cement plug installed on top of a mechanical plug.
Open hole to surface well barrier		
1. Cement plug	24	Cased hole cement plug.
2. Casing cement	22	Surface casing.

Notes

a. Verification of primary well barrier in the "liner case" to be carried out as detailed in Table 22.

b. The well barrier in deepest casing shoe can for both cases be designed either way, if casing/liner cement is verified and O.K.

c. The secondary well barrier shall as a minimum be positioned at a depth where the estimated formation fracture pressure exceeds the contained pressure below the well barrier.

Attachment 4

Casing Packer Setting Tool

Schlumberger

The Casing Packer Setting Tool (CPST) provides a reliable method of deploying plugs and packers in the wellbore during completion, isolation, or abandonment. The CPST features

- pressure-balanced design (does not have to overcome well pressure when setting)
- only one igniter, which incorporates a safety resistor for additional safety
- spiral pins to prevent tool presetting while running in the hole
- components coated in liquid nitride to improve life expectancy through greater surface hardness and increased corrosion resistance with no surface buildup
- no special alignment or orientation of components required during assembly or disassembly
- efficient redressing at the wellsite.

Application

- Setting plugs and packers

Mechanical Specifications

	CPST-AA	CPST-CC	CPST-BC
Temperature	400°F [204°C]	450°F [232°C]	400°F [204°C]
Pressure rating	15,000 psi [103 MPa]	15,000 psi [103 MPa]	15,000 psi [103 MPa]
Casing size—min.	5 in. [12.70 cm]	4½ in. [11.43 cm]	3½ in. [8.89 cm]
Casing size—max.	13⅜ in. [33.97 cm]	5½ in. [13.97 cm]	5 in. [12.70 cm]
Outer diameter	3.625 in. [9.21 cm]	2.75 in. [6.99 cm]	2.125 [5.40 cm]
Length	7.5 ft [2.29 m]	7.35 ft [2.24 m]	11.25 ft [3.43 m]
Weight	180 lbm [82 kg]	79.5 lbm [36 kg]	81.8 lbm [37 kg]
Bottom thread	Sleeve: 3½-in. [8.89-cm] 6 Acme Mandrel: 2-in. [5.08-cm] 6 Acme	Sleeve: 2½-in. [6.35-cm] 6 Acme Mandrel: 1-in. [2.54-cm] 8 UN	Sleeve: 2-in. [5.08-cm] 10 Stub Acme Mandrel: 1¹⁄₁₆-in. [4.29-cm] 16 UN

PR_04_006_0

August 2004
Produced by Marketing Communications, Houston.

www.slb.com/oilfield

$4^1/_2$-in and 5-in. PosiSet Thru-Tubing Plug ($1^{11}/_{16}$-in. OD)

Schlumberger

Description

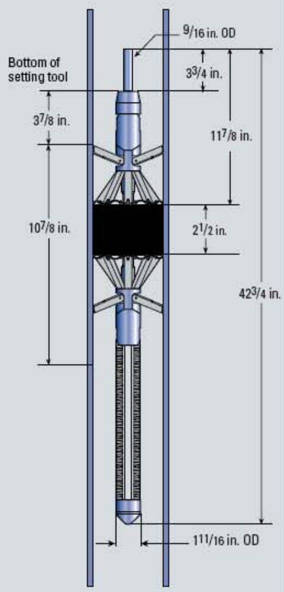
The new 5-in. PosiSet* Plug offers reliable plugback operations in $4^1/_2$-in. and 5-in. casing to 340°F through restrictions as small as 1.77 inches. The new PosiSet plug employs a compressed rubber seal, strong metal seal support and rugged anchors. Maximum pressure differential across the plug has been increased to 1000 psi in both directions. The drillable plugs are set with a long-stroke electrohydraulic setting tool, and released after shearing a 10,000-lbf tension stud. A standard casing collar locator is used for depth control.

Features

- Positive anchoring with upper and lower slips
- One-day simple operation
- Accurate depth control
- Non-explosive deployment
- Set Deviated holes including horizontal
- Open hole
- In perforations or screens

Specifications	
Outside diameter (in.)	$1^{11}/_{16}$
Minimum restriction (in.)	1.77
Maximum temperature (°F)	340
Maximum differential pressure (psi) (without cement plug)	1000

$4^1/_2$-in. and 5-in. PosiSet Thru-Tubing Plug ($1^{11}/_{16}$ in. OD)



March 2002

9⁵/8-in. PosiSet Thru-Tubing Plug (2⁵/8-in. OD)

Schlumberger

Description

The 9⁵/8-in. PosiSet* plug offers reliable through-tubing plugback operations in 9⁵/8-in. casing through a 2.75-in. minimum tubing restriction. The 9⁵/8-in. drillable plug consists of a compressed rubber seal, metal antiextrusion backups and rugged anchors. The 9⁵/8-in. PosiSet plug is set with a long-stroke electrohydraulic setting tool† and released with a 15,000-lbf tension stud. A standard casing collar locator is used for depth control.

Features

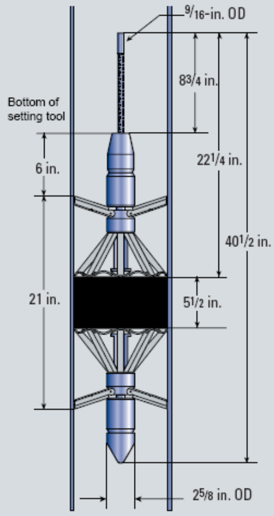
- Positive anchoring with upper and lower slips
- One-day simple operation
- Accurate depth control
- Non-explosive deployment
- Set deviated holes including horizontal
- Open hole
- In perforations or screens

Specifications

Outside diameter (in.)	2⁵/8
Minimum restriction (in.)	2.75
Maximum temperature (°F)	275
Maximum differential pressure (psi) (without cement plug)	500
Casing weights	29.3 to 53.5 lbm/ft

† 2¹/8-in. OD setting tool required

9⁵/8-in. PosiSet Thru-Tubing Plug (2⁵/8in. OD)



March 2002

*Mark of Schlumberger

Attachment 5

TECHNICAL SPECIFICATION – "ISLAND CONSTRUCTOR"

Date: 07.04.2009 Rev.6

Main particulars

Length over all: Approx.	120.2 m
Length between perpendiculars: Approx.	112.3 m
Breadth moulded: Approx.	25.0 m
Depth from Main deck:	10.0 m
Max draught:	8.0 m
Freeboard at max. draught: Approx.	2.0 m
Design draught:	7.0 m
Freeboard at design draught:	3.0 m

Tonnage, Capacities

Fuel Oil (MDO):		2212 m³
Portable fresh water:		990 m³
Technical fresh water:		3155 m³
Ballast water:		6850 m³
Liquid mud / Brine, 4 tanks , 2.8 t/ m³		509 m³
Brine, Marpol category B:		
Chemicals (LFL*) (2+2 tanks):		180 m³

List of substances to comprise:
- Glycol, MEG
- Diethylene glycol
- Ethylene glycol
- Methyl alcohol
- Xylenes

Lub. Oil:	Approx.	25 m³
Hydr. Oil:	Approx.	10 m³
Sewage:	Approx.	90 m³
Bilge / Sludge / Drop tank:	Approx.	70 m³
Deck load (CoG 1 m above M-deck.):		4000 t
(No equipment on deck)		10 t/m²
Capacity of skidding load aft of #55		60 t
Capacity of skidding load fore of #55		100 t
Deck area:	Approx.	1700 m²
Displacement in moonpool	Approx.	800 m³
Gross tonnage, international: GRT		11602
Net tonnage, international: NRT		3481

Maximum deck cargo capacity occurs at a draught less than Vessel maximum draught.

Performance

Trial speed at design draught in sea state 0-1 is approx. 13.5 knots.

Station-keeping capability:

Vessel is able to achieve ERN [99,99,99] at draught T=7.5 m according to Class requirements.

Class, Certificates and Regulations

The Vessel is designed to comply with rules, regulations and requirements laid down by the Flag State, IMO and the Classification Society (hereafter referred to as the Class).

Flag: NIS

IMO: Conventions, Codes and Resolutions that are adopted by the Flag State

SOLAS Chapter II-1, part B-1. Damage stability.IMO Resolution A.469(XII) – Guidelines for the design and construction of offshore supply vessels.

Class: Det Norske Veritas:
+1A1 with the following class notations:
Well Intervention Unit, SF, E0, DYNPOS-AUTRO, NAUT-OSV (A), CLEAN DESIGN, OPP-F, CRANE, COMF-V(3), COMF-C(3), LFL*, DK(+), HL(2,8), HELDK.

Reference system

All numerical units refer to the metric, SI system of measurement.

Operational Environment

The Vessel systems are designed for service with the following environmental conditions:
Ambient air temperature between –20 °C to +35 °C and sea temperature from 0 °C up to 32 °C.

Building method and Workmanship

All workmanship is carried out according to approved drawings. Steel work is carried out according to NS 6038 Accuracy in Shipbuilding.

The Vessel with machinery, equipment and accessories in all aspects is appropriate and solid. Due consideration is given to obtain easy access for operation of equipment and machinery and, as far as practicable, to obtain good access for future maintenance and repair.

The electrical installation is according to IEC norms, and when relevant, DIN norms.

Spare parts

Spare parts for all equipment, machinery etc. according to requirements from Class and relevant Authorities and according to suppliers' normal standard.

Instruction manuals

Instruction Manuals in four copies for all machinery and equipment is delivered. Manuals are in English.

Maintenance and spare part system

Maintenance and spare part system including software, computers, printers and implementation of maintenance procedures and spare part data is installed.

2. HULL AND STRUCTURE

Hull materials

All materials is new and of marine quality according to Class regulations, and where required, with certificates. Materials are suitable for the service intended with this Vessel.

Blasting, shop priming, cleaning of materials

Steel building materials are grit blasted, and primer of approved type is applied. Paint work is performed on clean surfaces, according to manufacturer recommendations for specified coating.

Steel construction in general

All dimensioning is according to Class requirements and recommendations from noise and vibrations analysis.
Frame spacing is 700 mm.
Hull structure is strengthened for docking with min. 1000 t deadweight

Fenders

8 off rubber D-fenders, each with length according to final arrangement, arranged on flat side both port and starboard side according to the General Arrangement plan.

Helideck

The Vessel is equipped with a helicopter landing deck on the wheelhouse roof. Size: 22.8 m diameter, octagonal shape.
Equipped and arranged for helicopter of type, EH101 with a "D"-value = 22.8 m and "t"-value = 14.6 t.
Approvals: DnV, Luftfartsverket UK-CAA CAP-437
Reception for helicopter passengers is arranged on D-deck.

Moonpool

The hull is equipped with a moonpool with net opening of approx. 8.0 x 8.0 m and arranged with a surrounding splash zone of sufficient size. Transition from moonpool to bottom of Vessel shall be done by a radius of approx. 600 mm.

The moon pool shall be equipped with sufficient air ventilation to either ship side.

ROV Hangar

The dual ROV hangar is built as a welded steel construction and is an integrated part of the superstructure. Part of the mid section shall be built as a separate compartment.
Opening for a large side port, approx. 5 x 10 m on each side of Vessel and an aft port approx. 5 x 8 m is arranged.

ROV launch and recovery system (LARS)

Vessel is equipped with 2 off "Gantry" type LARS, one to each side in ROV hangar.

Crane foundation

Foundation for an offshore working crane is arranged as indicated in General Arrangement drawing; approx. frame 49 at Starboard side, and dimensioned for a crane with 250 t SWL at 12 m outreach and dynamic factor of 2.0.

Moonpool tower foundation

Foundation for a construction / Well intervention tower shall be arranged on main deck level at each corner of the moon pool as indicated on the General Arrangement plan.

Shelter guard

On main deck a shelter guard, with gangway on top is fitted on each side frame 46-48. Height approx. 2 950 mm above main deck, breadth approx. 1 500 mm PS and 1 850 mm SB. Shelter guard is partly open against deck and free passage on SB side is approx. 1 000 mm. Aft of frame 46, including stern, no gangway is arranged on top and height is approx. 2 700 mm above main deck.

Four removable and bolted units are arranged on PS frame 12 to 46 according to the General Arrangement plan.

Impressed current protection

An impressed current cathode protection system is fitted.

2. HULL AND STRUCTURE

Hull materials

All materials is new and of marine quality according to Class regulations, and where required, with certificates. Materials are suitable for the service intended with this Vessel.

Blasting, shop priming, cleaning of materials

Steel building materials are grit blasted, and primer of approved type is applied. Paint work is performed on clean surfaces, according to manufacturer recommendations for specified coating.

Steel construction in general

All dimensioning is according to Class requirements and recommendations from noise and vibrations analysis.
Frame spacing is 700 mm.
Hull structure is strengthened for docking with min. 1000 t deadweight

Fenders

8 off rubber D-fenders, each with length according to final arrangement, arranged on flat side both port and starboard side according to the General Arrangement plan.

Helideck

The Vessel is equipped with a helicopter landing deck on the wheelhouse roof. Size: 22.8 m diameter, octagonal shape.
Equipped and arranged for helicopter of type, EH101 with a "D"-value = 22.8 m and "t"-value = 14.6 t.
Approvals: DnV, Luftfartsverket UK-CAA CAP-437
Reception for helicopter passengers is arranged on D-deck.

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Four removable and bolted units are arranged on PS frame 12 to 46 according to the General Arrangement plan.

Impressed current protection

An impressed current cathode protection system is fitted.

3. TOPSIDE

Module Handling Tower

Vessel is equipped with an MHT, with centre at moon pool Approx. frame 68. Structural steel applied is S355J2G3. Stairtower is in aluminium.

Technical data

Dimensions: (center line main structure)	
Width between center of interface point (port – starboard):	8.1 m
Length center of interface point (fwd – aft):	8.1 m
Height to top of crown beam:	32.3 m

Equipment in MHT

1 off	Operators Cabin with three operator chairs	
1 off	Umbilical system	
1 off	Work basket	
1 off	Inline tensioner	SWL 12 t
1 off	Cursor winch	SWL 12 t
4 off	Utility winches	SWL 3 t
4 off	Guide wire winches	SWL 5 t
1 off	Wireline cylinder – stroke	8 m
1 off	Manrider winch	
4 off	Guidewire pullback arm	
1 off	Module hang-off trolley	
1 off	Module guide arm	
1 off	Turnover sheave and crown block	
1 off	Upper cursor frame	
1 off	Lower cursor frame	
1 off	Main hoisting wire and hook	
	Well-intervention mode (single line)	SWL 100 t
	Drilling mode (two falls)	SWL 200 t

SWL is handled on two parts.
Due to static capacity of the winch, maximum SWL for the MHT cannot be handled. Maximum SWL is 200 t on two falls. However, the MHT is rated for maximum SWL 300t.

60 t SWL is to be guided by the cursor frames with COG no higher than 15 m above deck during wellintervention mode.

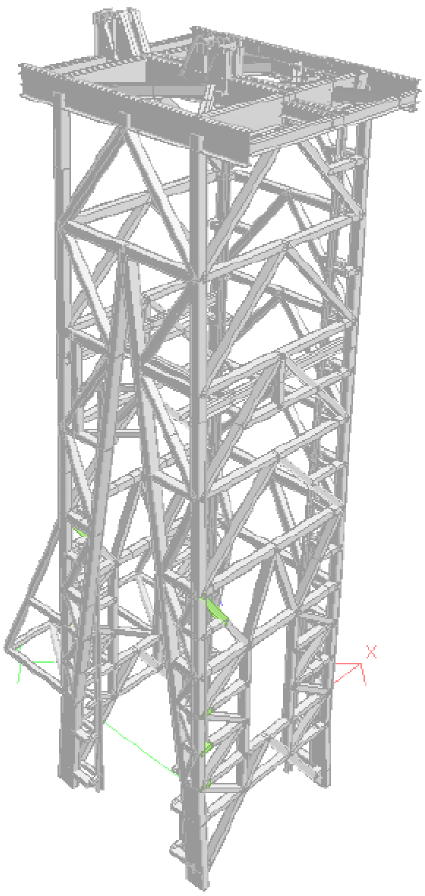
Main Winch

The 100T AHC Winch System has an active and a passive side and consists of accumulator cylinder (AC), air pressure vessels (APV) containing nitrogen, hydraulic pumps, motors and a crane control system (CCS) to control the different lifting modes and transitions between the modes.

The different lifting modes are:
- Normal mode
- Active heave compensation
- Constant tension
- Emergency lowering

Technical Data

SWL:	100 t @ 0 – 1100 m water depth.
Grooving of drum	Lebus
Wire rope diam.:	66 mm
Wire length:	1100 m
Wire layers:	7
Number of gears:	10
Motor:	Hydraulic
Line speed (AHC mode):	0-165 m/min.
Lifting speed: (NORMAL):	0- 30 m/min.
Operation:	PLC
Hook stop:	Up / down



The MODULE HANDLING TOWER is prepared for Coiled tubing operations.

Tower Cabin

The obtained objectives with the Tower Cabin are improved for safety and fit-for-purpose solution. It mandates to provide a dedicated safe and efficient operational system.

With the tree dedicated operation chairs the Tower Cabin is well configured to accommodate the systems in a common operation. The potential operational synergy within the cabin is therefore a critical part of the improved safety operational aspect.

Technical data

Pressurized cabin for three operation chairs w/control system and working stations.

3 off	Operation chairs (Tower / Wireline / SSL)
4 off	Working stations (Logging operations / Client rep.)

Skidding System

The objective of the horizontal skidding system is to provide safe and efficient deck transportation of subsea equipment modules to and from the moonpool, where a vertical lifting system takes over the modules and provides vertical transport to and from the seabed.

Technical data

2 off	Push-Pull Units		
6 off	Tool Pallets	SWL	60 t
2 off	Tool Pallets	SWL	100 t
2 off	Control Stand		
	Skidding Beams	(Layout)	

The transport takes place on a system of skidding beams (rails), welded to the ship's main deck. Skidding System capacity is 60 t aft of moon pool and 100 t capacity foreward of moonpool.

Moonpool Door

The construction has two main beams for the same span length as the moonpool. The opening mechanism is folding the door down into the moonpool. The moonpool door is supported AFT in the moonpool.

Moonpool Door can be operated from local control panel or derrick cabin

Technical data

1 off	Carrying capacity on main skidding beams	SWL	150 t
4 off	Hinged grating ("flaps") max.		300 kg/m²

Incorporated in the door structure are sections of the skidding beams, which make the skidding beams continuous as the door is closed and thus allowing tools and equipment to be run straight trough the tower.

Moonpool door have an ø1000 hole in centre of moonpool which have hinged covers (2 halves).
When the "flaps" are closed, the moon pool door will form a complete safe and stable working area for the operators.

Cursor Frames

The Cursor Frames & Winch system consists of an Upper and a Lower Cursor Frame, an upper cursor lock, a cursor winch, and remote controls in the Master Control Cabin. The system is fitted to stabilize the main hook and heavy equipment handled inside the tower against horizontal movements.

The purpose of a Cursor System is to provide safe handling of tools/equipment and also guide the hook inside the tower. When the modules are lifted inside the tower and when they are lowered through the splash zone it is considered being a critical part of the operation. The Cursor Frame System takes care of the guiding to avoid damage to equipment and/or personnel.

The Cursor System is running on two guide rails (HEM 220) mounted inside FWD side of the Tower continuing down into the moonpool. The UCF is equipped with a docking arrangement for the main hook. The UCF will normally follow the main hook movement.

The LCF are included with a hinged buffer support

Cursor Line Winch

The cursor winch is a dual unit with hydraulic motors on both ends of the drum. The drum has two parallel wires that via sheaves at the tower top are permanently hooked to the two lifting eyes of the lower cursor frame.

Technical data

1 off Cursor winch	SWL 12 t
2 off Wire length:	60 m
2 off planetary gearboxes	w/failsafe disc brake

Guideline Winches

The guideline system is a wire system for guiding (not lifting) of subsea equipment modules during transport between the ship and the seabed. Retrieval of pod's on the BOP if required.

The holding capacity of the failsafe brake allows the winch to hold the load according to NPD rules.

Technical data

4 off Guideline Winches	SWL 5 t @ 0 – 600 m water depth.
Grooving of drum	Lebus
Wire rope diam.:	19 mm
Wire layers:	7 layers
Gear:	Planetary
Motor:	Electrical, Ex zone 2
Line speed (AHC mode):	0-186 m/min.
Lifting speed: (NORMAL)	0- 75 m/min.
Operation:	PLC
Wire stop:	Up / down

Pullback Arms

In performing the vessel's tasks a wire pull-back device is required above the moonpool. The PBA's will ensure that the four GLW's may be inserted or retrieved from the guide funnels forming part of the modules going subsea.

Technical data

4 off Pull-Back Arms SWL 700 kg
@ a working envelope of 70° horizontal by 60° vertical sector

The PBA's are designed to work in cooperation with the Guide- line Winches, the Module Handling Tower and the Moonpool Doors.

Wire Line Compensator

The Wire Line compensator with its top & bottom sheave is guided and supported internally inside tower, with a stroke of 4000 mm and 80° horizontal slewing. The Compensated Wire Line Cylinder is designed and rated for the following lifting scenario:

a) 10 tonnes static load (line pull) on assembly in operating position or
b) 6 tonnes compensating load (line pull), also in operating position.

Umbilical Compensator

The Umbilical compensator with its top & bottom sheave is guided and supported internally inside the tower. The heave compensated system is handled with an inline tensioner.

Technical Data

Heave comp. pull:	10 t (incl.deadwight)
Static tension.:	17 t
Compensated movement:	+/-3.5 m
Amplitude speed:	2.0 m/s

Umbilical Reels System

The Reel Control Cabinet handles both the control reel and the chemical reel.

Control Reel

The Control Reel handles the electro hydraulic system, and is the communication link to Stack and control chair.

Pull first layer:	9 t
Umbilical outer diam.:	38 mm
Umbilical length:	1500 m
Weight in Seawater:	3.5 kg/m
Umbilical SWL	16 t
Umbilical layers:	7 layers
Number of motors:	2
Motor:	Electrical
Lifting speed: (NORMAL)	0-40 m/min
Operation:	PLC
Umbilical stop:	Up / down

Chemical Reel

The Chemical Reel handles fluid of Methanol or MEG

Technical Data

Pull first layer:	5 t
Umbilical outer diam.:	51 mm
Bore size:	19 mm
Working Pressure:	10000 PSI
Umbilical length:	1500 m
Weight in Seawater:	0.92 kg/m
Umbilical SWL	12 t
Umbilical layers:	7 layers
Number of motors:	1
Motor:	Electrical
Lifting speed: (NORMAL)	0-40 m/min
Operation:	PLC
Umbilical stop:	Up / down

Mixing System

The Mixing system involves the following main components:

- Deck located batch mixing tank with mixing nozzles.
- Containerized mixing unit with hopper and dual circulation pumps.
- Two Diesel driven Well service pumps operated from tower control cabin or locally.
- Hose reel and Hose for pumping from vessel to the wellhead.
- Deck equipment for handling hose in an operating condition.
- Vessel hull tanks, pipes and transfer system for typically brine/mud

Well Service Pumps

There are two well service pumps; both pumps are diesel driven quintaplex plunger pumps. The pump capacity is subject to configuration. The two pumps works on parallel lines, both from the tanks and to the reels.

The pumps handle media of high density high viscosity. The fluids to be pumped are in general:

- Water
- Gels
- Slurries
- Chemicals

Technical data

Basic Pump operating capacity, the pumps are to be operated locally or remote from the tower cabin. Plunger type. diesel driven

Qty.	Pump	Capacity
2 off	Well Service Pumps	548 LPM each 690 bar, at 200 rpm
	Quintaplex Plunger Diesel driven.	2.75"-3.00" 1100 bhp

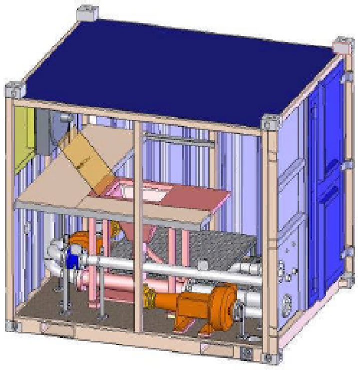
Max discharge pressure:
2.75"-3.00" plunger is 1013 bar / 14,700psi max
Option: (3.25"-4.50" plunger is 717 bar / 10,400psi max)

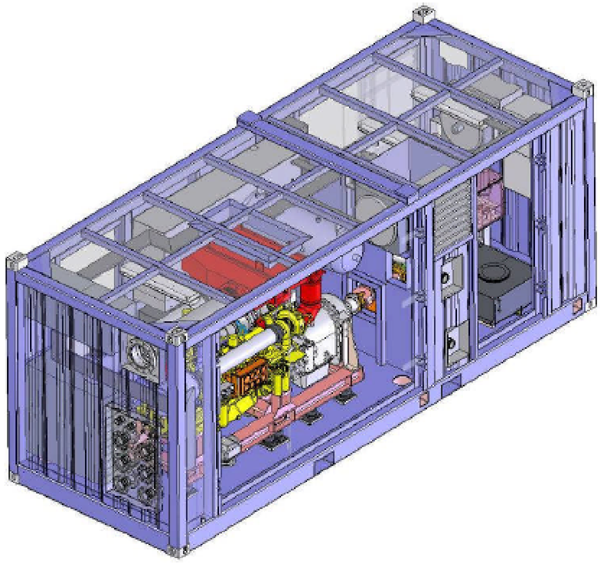
Kill Hose Reels

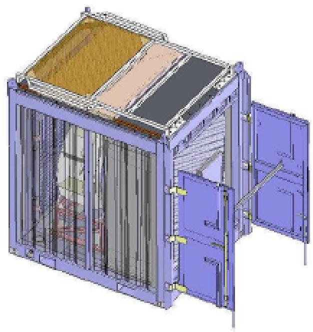
The two Kill Hose Reels handles the fluids from Kill Pumps.

Technical Data

Pull outer layer:	4 t
Umbilical outer diam.:	2"
Working Pressure:	10000 PSI
Umbilical length:	750 m
Umbilical SWL	12 t
Umbilical layers:	7
Number of motors:	1
Motor:	Hydraulic
Lifting speed: (NORMAL)	0-40 m/min
Operation:	PLC
Umbilical stop:	Up / down







Coiled Tubing and Rigid Riser System

The Coiled Tubing and Rigid Riser System will be designed in accordance to ISO 13628-7
Operation of the system will focus on a minimum of manual operations and a fast change from riser less intervention to a rigid riser system.

Riser stack is based upon 7 1/16" nominal bore diameter and planned with a 5 5/8" ID riser down to 600 meters water depth for the first season. Working pressure is 5000 PSI.

The top side part consists of two frames. One Coiled Tubing Frame with CT Injector, CT BOP and Surface Tree and one Gimbal Frame with a gimbal function for storm hang off.

The subsea part consists of a tension joint, lubricator valve, swivel, weak link, stress joint, EDP and WCP.

Deployment is done by the main winch, riser tension and top tension system will support the stack when in operation.

The Well Control Package WCP is the same as for the Riserless Light Well Intervention System RLWI MkII operating on Constructor. This is FMC's latest generation RLWI totally electrical controlled with subsea hydraulic power.

EDP is based upon the Lower Lubricator Package for the same RLWI MkII added a Retainer Valve.

The significant wave height for riser related operations will most likely be Hs = 5 meter with Hs = 4 meter for horizontal skidding and modules deployment.

Top Tension System	8 x 45 kips
Riser Tension System	8 x 45 kips
Coiled Tubing	2 3/8"
CT Frame	45 ton
Gimbal Frame	25 ton
EDP	21 ton
WCP	44 ton

Lower Lubricator Package

Well Control Package

FMC Technologies

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Page 1 of 2

Riserless Light Well Intervention System RLWI MkII

design features

- inspection and maintenance of subsea wells by inserting downhole tools into the well under full well pressure by the use of wireline or slickline
- subsea flushing of hydrocarbons from lubricator to well (patented)
- subsea closed hydraulic systems
- subsea grease injection pump and reservoir
- all-electric control system with subsea hydraulic power generation
- designed according to relevant API and ISO standards

system data

design water depth	1000 meter
design pressure	690 bar (10 000 psi)
bore diameter	7-1/16 " (179.4 mm)
total weight (air)	69 ton
total height	33 meter
maximum toolstring length	22 meter
temperature rating of barrier package	iso class U (-18°C – 121°C)
temperature rating of lubricator	iso class S (-18°C – 66°C)

installation data

pressure control head	0.7 ton	4 meter
lubricator section	24.0 ton	23 meter
well control package	44.0 ton	6 meter

power requirements

power to subsea package	2 x 8 kW
chemical injection unit	2 x 55 kW

umbilicals

control umbilical (electric & fibreoptic)	Ø38 mm, 3.3 kV, 24 + 2 conductors
chemical umbilical	Ø51 mm, 690 bar (10 000 psi)

fluids

well control package hydraulic fluid	brayco sv/b
lubricator hydraulic fluid	oceanic hw 443
flushing and pressure testing	meg-5 (monoethyleneglycol)
grease injection unit	biodegradable grease ltlv
xmas tree hydraulic fluid	field specific

system shutdown levels

- production shutdown	close all valves outside main bore
- emergency shutdown	sequential shutdown of all valves and wireline cutting
- emergency quick disconnect	sequential shutdown of all valves, wireline cutting and disconnection of umbilical

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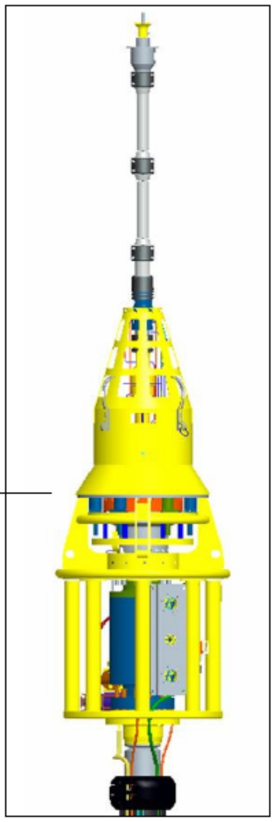
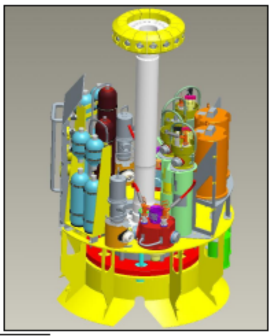
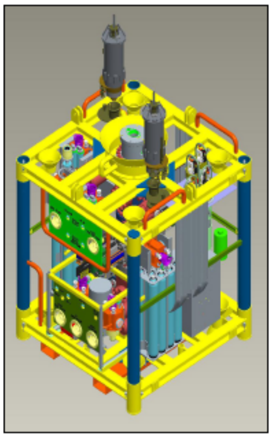
P.O. Box 440
1373 Asker, Norway
www.fmctechnologies.com/Subsea

Riserless Light Well Intervention System RLWI MkII







pressure control head	
weight	0.7 ton
dimensions (height x diameter)	3.9 meter x max. Ø0.73 meter
flow tube/stuffing box sizes	0.125" slickline, 7/32", 5/16", 7/16" braided wireline and composite cable

lubricator section	
connector to pressure control head	
weight	24.0 ton
dimensions (height x diameter)	23.0 meter x max. Ø2.30 meter
wireline-cutting ball valve	for all slickline, braided wireline and composite cable dimensions
9-function subsea control modules	2 off
high pressure hydraulic units	2 off
hydraulic fluid	oceanic hw 443
hydraulic fluid reservoir	100 liter
high pressure grease units	2 off
grease fluid	biodegradable grease ltlv
grease fluid reservoirs	2x150 liter
connector to well control package	13-5/8" KC 6-17 riser connector

well control package	
weight (without xmas tree adapter)	44.0 ton
dimensions (w x d x h)	3.6 x 3.6 x 4.9 meter
subsea control module	4 off
hydraulic fluid	brayco sv/b
hydraulic fluid reservoir	500 liter
valve cutting capacity:	
- gate valve	2-7/8" coiled tubing
- shear seal ram	according to API 16A
bottom end connection	13-5/8" 10k speedloc clamp

xmas tree interface module	
9-function subsea control modules	1 or 2 off
high pressure hydraulic units	1 off (105 - 345 bar)
hydraulic fluid	field specific
hydraulic fluid reservoir	1000 liter

control system

- all electric topside control system with subsea hydraulic power generation
- fully redundant power and communication systems
- controllers equipped with back-up battery for autonomous control
- all communication between topside and subsea by 10 Mbit/s ethernet

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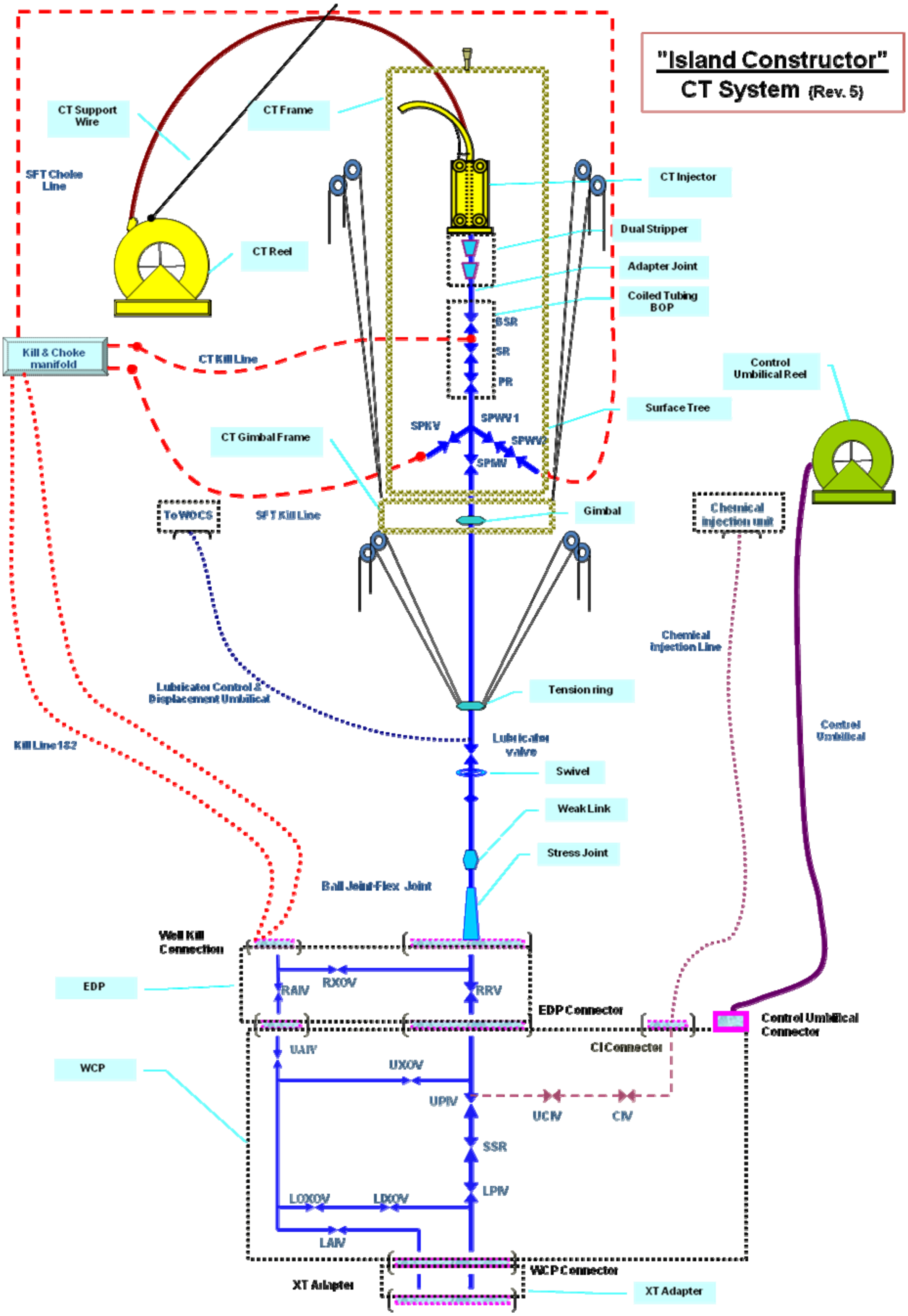
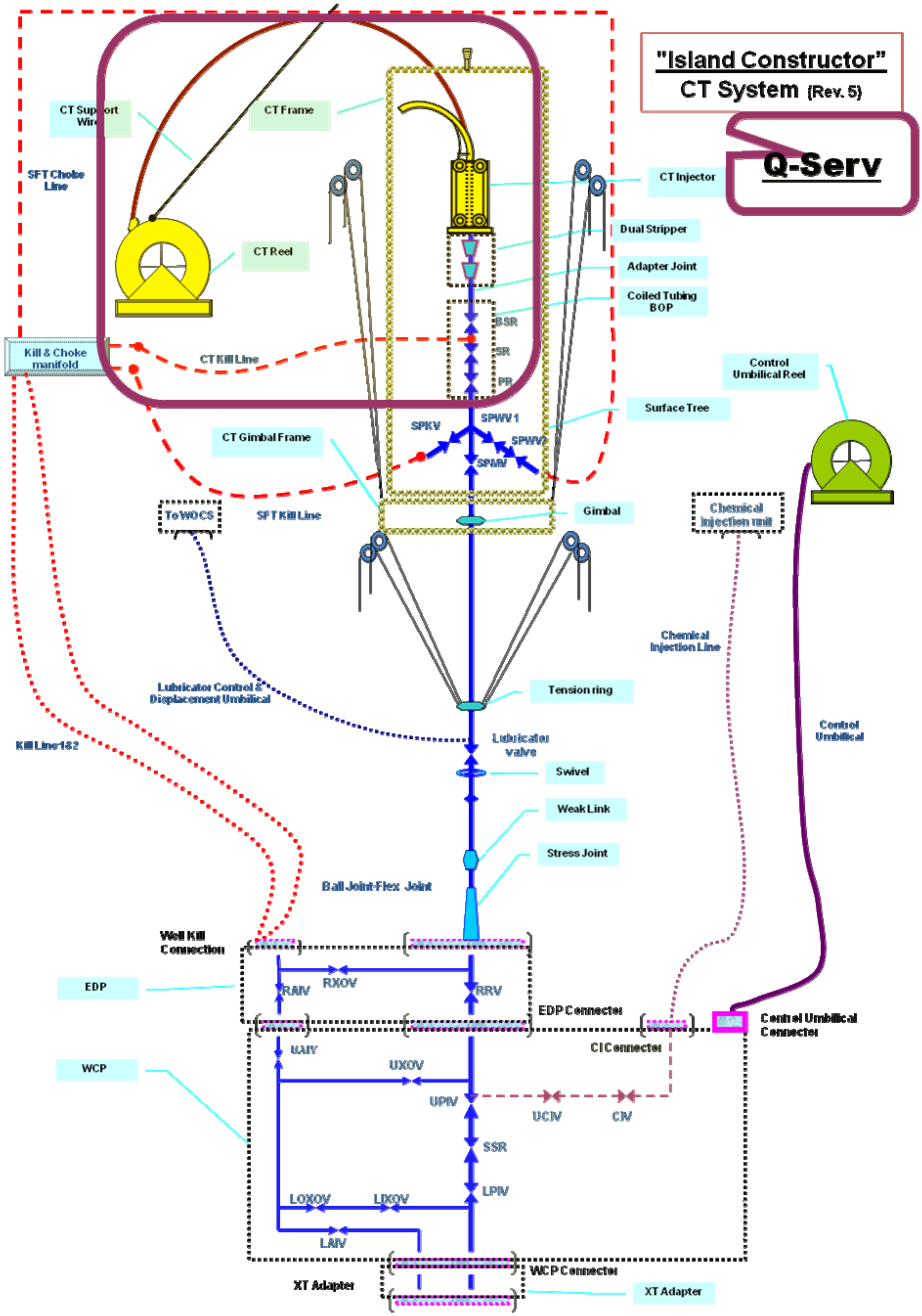
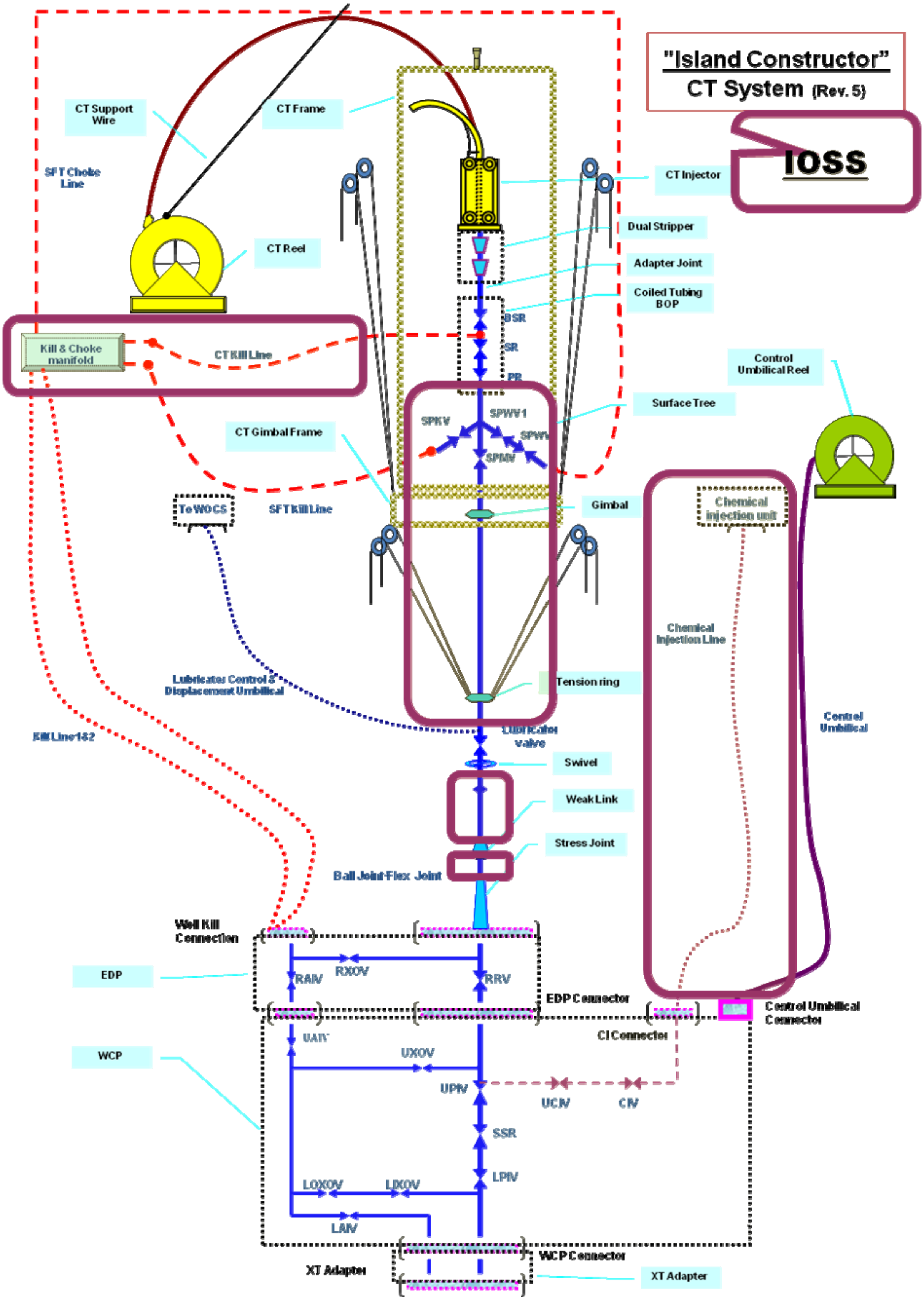
updated: PE 20080411

Attachment 7





"Island Constructor"
CT System (Rev. 5)
Q-Serv
CT Support Wire
CT Frame
SFT Choke Line
CT Reel
CT Injector
Dual Stripper
Adapter Joint
Coiled Tubing BOP
BSR
SR
PR
Kill & Choke manifold
CT Kill Line
Control Umbilical Reel
Surface Tree
SPKV
SPWV1
SPWV2
SPMV
CT Gimbal Frame
Gimbal
To WOCS
SFT Kill Line
Chemical injection unit
Chemical Injection Line
Lubricator Control & Displacement Umbilical
Tension ring
Kill Line1&2
Control Umbilical
Lubricator valve
Swivel
Weak Link
Stress Joint
Ball Joint-Flex Joint
Well Kill Connection
EDP
RXOV
RAIV
RRV
EDP Connecter
CI Connecter
Control Umbilical Connecter
WCP
UAIV
UXOV
UPIV
UCIV
CIV
SSR
LPIV
LOXOV
LIXOV
LAIV
WCP Connecter
XT Adapter
XT Adapter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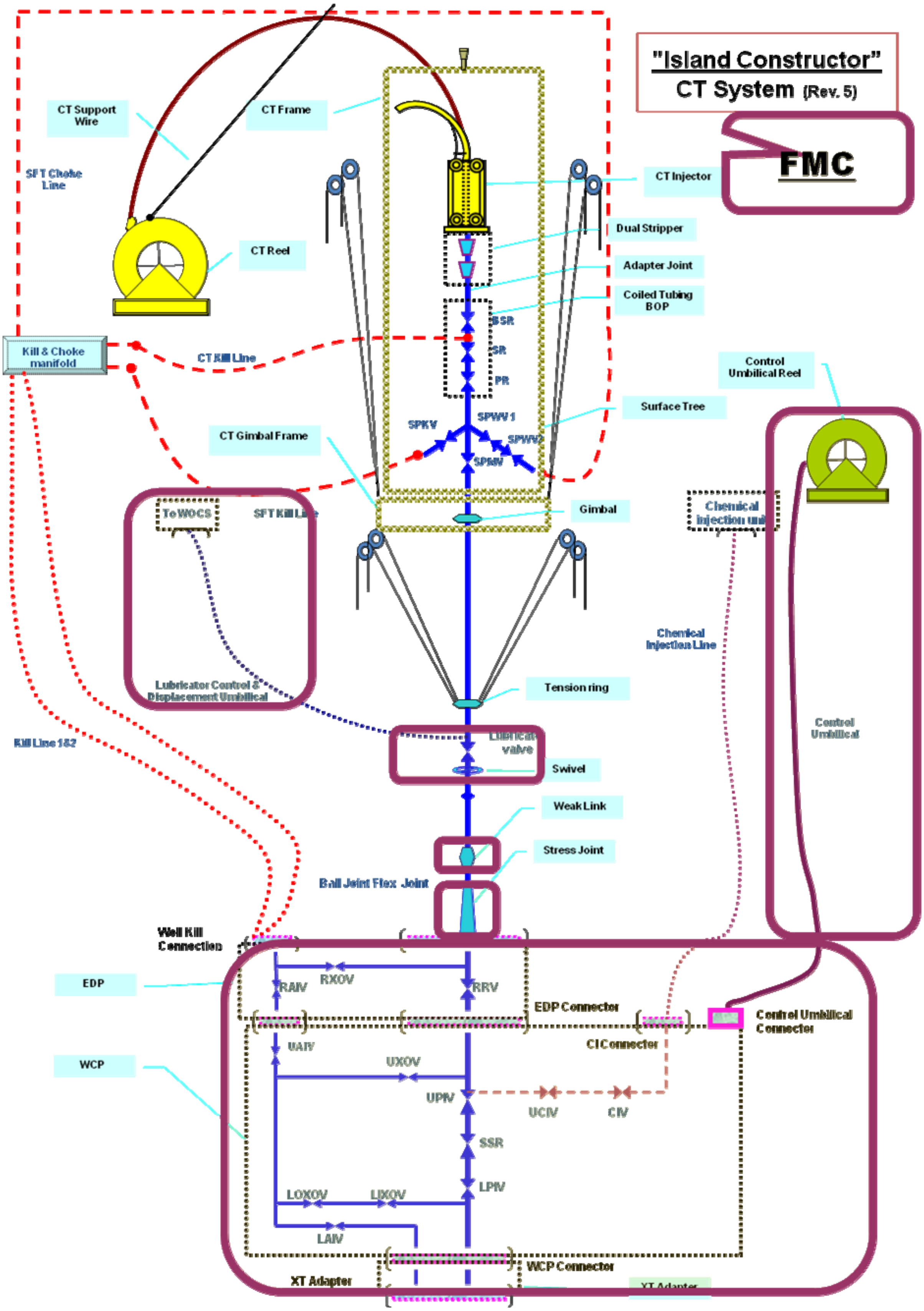
"Island Constructor"
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CI Connector
WCP
UAIV
UXOV
UPIV
UCIV
CIV
SSR
LPIV
LOXOV
LIXOV
LAIV
WCP Connector
XT Adapter
XT Adapter

Attachment 8

1. General design requirements

1.1 Design Data

Design Data refers to SOR rev 4

1.2 Environmental Criteria

The following design criteria shall be considered for the design of the Riser System for Schiehallion.

Maximum Water	600m
Minimum Water	300m
Seawater Ambient	**4° C**

1.3 Well Operations - Well Conditions

Producer Well	
Well Head Flowing Pressure	1200 psi
Well Head Shut-In Pressure	2500 psi
Operating Pressure	1000 psi
Well Head Flowing Temperature	60° C
Well Head Shut In Temperature	4° C

Injector Well	
Reverse Circulation Pressure	4500 psi
'Conventional Circulation' Pressure	1500 psi
Injection Pressure	4000 psi

Bullheading Pressure	4000 psi

1.4 High volume pumping activities

Rate	30 bpm
Fracture stimulation Acid Brightwater	5000 bbls, able to pump and filter sufficient to achieve 50bpm. (probably around 2500 bbls concentrated acid) +/- 1000000 bbls Polymer concentration of 1.5% typical so 98.5% seawater and 1500 bbls of polymer for a 1 million bbl treatment.

1.5 Operational Durations (Connected)

CT PLT on producer / injectors CT Cleanout on Producer / injectors Riser deployment of	21 days
High volume pumping activities	48 hours to 30 days

1.6 Well circulation capabilities

Full Flow Water Pumped from FPSO Reverse Return Flow	(CT) Pump Rate 1500 L/min Return Fluid 99.5% water Return flow processed and discharged to sea
Full Flow Hydrocarbon Return	(CT) Pump Rate 1500 L/min Closed Loop Hydrocarbon Return Sand, scale and metal particles present in flow
Full Flow Hydrocarbon Return and Flowing Well	(CT) Pump Rate 1500 L/min Well flow rate 660 L/min Total Return Flow 2160 L/min Flare capability 660 L/min Sand, scale and metal particles present in flow
Gas Injection	NA

1.7 Surface Tree and BOP

Surface Tree gate valves and BOP ram requirements are presented in the following Table.

Nominal Bore SFT	7 1/16”
Nominal Bore Coil Tubing BOP	4 1/16”
Design Pressure	5,000 psi

1.8 Riser Criteria

Riser Criteria	**Design Parameter**
Design Life (Total) Service Life (In operation)	10 Years 5 Years
Design Pressure	5000 psi
Riser Maximum Temperature	82° C
Riser Minimum Temperature	-18° C
Riser drift Reference Riser Case Minimized Riser Case	6.437” 4.86”
Internal Corrosion Allowance	max 3.0 mm allowed
CT OD CT Wall Thickness CT Grade	2 3/8” ~ 2 7/8” 0.203” QT900 - 95 ksi

Slick line and Braided line Sizes	0.092” to 0.125” Slick line 7/32” to 7/32” and 5/16” Braided line
E-Line Sizes	Mono, 7/32” – 5/16” – 7/16” Hepta, 15/32”
Gases	Nitrogen Internal pressure
Fluid pH	5.2
Chemicals	H2S≤ 500ppm CO2 ≤1 mol % N≤0.274 mol % (HOLD)
Riser Criteria	Design Parameter
Injected/Introduced Fluids/Gases	Glycol (1097 kg/m3) Methanol (790 kg/m3) Completion Brine (1200 kg/m3) Nitrogen (HOLD) Inhibited Seawater (1025 kg/m) Scale Inhibition Chemicals (1000 kg/m3)
Solids	Sand: 2 kg per 1000 bbls

1.9 Riser Connector/Couplings

VIV Fatigue Safety Factor **Wave induced Fatigue Safety F**	20 10
Non re-cut capable connectors Minimum No Make/Break Cycles	100
Repairable Connectors Minimum No Make/Break Cycles	25 with minimum of three re-cuts possible for Pin and Box ends

1.10 Emergency Disconnect Package

Minimum Make/Break Cycles (One ‘cycle’ defined as latching, then unlatching the connector)	25

1.11 Subsea Tree Weight & Dimensions

Tree Weight (Dual Bore 7” x 2”) Tree Running Tool (estimate inclusive of Speed loc Lift Cap) Cursor Guide Frame	41 tonnes 18 tonnes 4 tonnes
(Dual Bore 7” x 2” - Plan Length* Width**	 199” [5055 mm] 132” [3353 mm]

* Equidistant from Mandrel centre

** Offset from Mandrel centre line 76” and 56” respectively