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## Table of Contents

<b>ABBREVIATIONS .....</b>	<b>7</b>
<b>ABSTRACT .....</b>	<b>9</b>
<b>INTRODUCTION .....</b>	<b>11</b>
<b>1. COILED TUBING (CT): .....</b>	<b>15</b>
1.1 HISTORY:.....	15
1.2 COILED TUBING EQUIPMENT.....	16
1.2.1 <i>The Coil</i> .....	16
1.2.2 <i>Injector Head</i> .....	18
1.2.3 <i>The Reel</i> .....	21
1.2.4 <i>Pressure control Equipment</i> .....	22
1.2.4.1 Stripper (Stuffing Box) .....	22
1.2.4.2 Blow out Preventer (BOP).....	23
1.2.4.3 Blind ram assembly.....	23
1.2.4.4 Shear ram assembly.....	24
1.2.4.5 Slip ram assembly .....	25
1.2.4.6 Pipe ram assembly .....	25
1.2.4.7 Safety Head .....	27
1.2.5 <i>CT Power Units</i> .....	27
1.2.6 <i>CT control cabin</i> .....	28
1.2.7 <i>CT Tools</i> .....	29
1.2.7.1 Connectors .....	29
1.2.7.2 CT Valves .....	31
1.2.7.3 Dual activated circulation sub .....	32
1.2.7.4 Disconnects .....	33
1.3 WELL BARRIER SCHEMATICS (WBS).....	34
<b>2. CT APPLICATIONS:.....</b>	<b>35</b>
2.1 SAND FILL REMOVAL.....	35
2.2 WELL UNLOADING AND WELL START UP.....	36
2.3 FORMATION FRACTURING/ACIDIZING.....	37
<b>3. CTD HISTORY ON GULLFAKS A: .....</b>	<b>38</b>
3.1 34/10- A-10.....	38
3.1.1 <i>Rig up</i> .....	39
3.1.2 <i>Pre drilling preparations</i> .....	39
3.1.3 <i>Milling Exit window</i> .....	39
3.1.4 <i>Drilling in Openhole</i> .....	40
3.2 NO 34/10-A-19.....	40
<b>4. EXPERIENCE FROM OTHER OIL COMPANIES:.....</b>	<b>42</b>
4.1 TERENGGANU OFFSHORE – MALAYSIA .....	42
4.1.1 <i>Introduction</i> .....	42
4.1.2 <i>Wellbore Stability</i> .....	42
4.1.3 <i>Hole Cleaning</i> .....	43
4.1.4 <i>Operation Execution</i> .....	43

4.2	CLEVELAND FORMATION – USA.....	46
4.2.1	Introduction.....	46
4.2.2	Wellbore Stability.....	47
4.2.3	Hole Cleaning.....	48
4.2.4	Operation Execution.....	48
<b>5.</b>	<b>CTD FEASIBILITY: .....</b>	<b>49</b>
5.1	TECHNICAL FEASIBILITY .....	51
5.1.1	Well Screening.....	53
5.1.2	Kick off point (KOP).....	53
5.1.3	Well Path Modelling.....	54
5.1.3.1	A-11 A summary of modelling results.....	54
5.1.3.2	A-14 A Summary of modelling results.....	55
5.1.3.3	A-23 A summary of modelling results.....	56
5.1.3.4	A-26 A summary of modelling results.....	57
5.1.3.5	A-31 A summary of modelling results.....	58
5.1.4	Hydraulic Design.....	59
5.1.4.1	Hole Cleaning.....	60
5.1.4.2	Mud design.....	61
5.1.5	Underbalanced and managed pressure CTD.....	63
5.1.6	Well Control in Slimhole.....	63
5.1.7	CTD Bottom Hole Assembly (BHA).....	64
5.1.7.1	Orienter .....	65
5.1.7.2	Downhole Motor .....	66
5.1.7.3	Bit Requirement: .....	68
5.1.7.4	Logging tools.....	70
5.1.7.5	Whipstock.....	70
5.1.8	CTD Surface Equipment.....	71
5.1.9	Tubing Selection.....	72
5.1.9.1	Tubing Tension.....	72
5.1.9.2	Weight on Bit (WOB).....	72
5.1.10	Well Integrity.....	74
5.1.10.1	Drilling operation.....	74
5.1.10.2	Plug and abandonment (P&A) .....	75
5.2	PLATFORM AND UTILITIES .....	76
5.2.1	Personnel on Board (POB) .....	76
5.2.2	Space on deck.....	76
5.3	TIME AND COST .....	76
<b>6.</b>	<b>NEW TECHNOLOGIES .....</b>	<b>80</b>
6.1	RIB STEERABLE MOTOR (RSM).....	80
6.2	HYDRASET™ CT JAR.....	82
6.3	DYNAMIC EXCITATION TOOL.....	83
6.4	OPEN HOLE CLAD (OHC) .....	84
6.5	CTD OPPORTUNITIES IN 10 YEARS.....	85
<b>7.</b>	<b>CTD COMPARED TO THROUGH TUBING ROTARY DRILLING (TTRD).....</b>	<b>87</b>
<b>8.</b>	<b>CONCLUSION.....</b>	<b>90</b>
<b>9.</b>	<b>REFERENCES .....</b>	<b>93</b>

**Master Thesis**

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<b>APPENDIX A</b>	<b>CTD BHAS.....</b>	<b>97</b>
<b>APPENDIX B</b>	<b>CANDIDATES CTD WELLS IN GULLFAKS-A .....</b>	<b>100</b>

## List of Figures

Figure 0-1: CTD well's design [13].....	14
Figure 1-1: Evolution of CT sizes [8].....	15
Figure 1-2: CT Butt Welding [8].....	17
Figure 1-3: CT Bias Welding [8].....	17
Figure 1-4: CT manufacturing process [8]. .....	18
Figure 1-5: CT Injector Head and Gooseneck [8].....	19
Figure 1-6: CT Grippers and Injector Head's Chains [8]. .....	20
Figure 1-7: CT Gripper engaged to the CT while running in hole [8].....	20
Figure 1-8: CT reel [8].....	21
Figure 1-9: CT Strippers [8]. .....	22
Figure 1-10: Quad rams - CT BOP [8]. .....	23
Figure 1-11: CT BOP's blind rams [8].....	24
Figure 1-12: CT BOP's shear rams [8].....	24
Figure 1-13: CT BOP's Slips types [8].....	25
Figure 1-14: CT BOP's Pipe ram assembly [8]. .....	26
Figure 1-15: Quad BOP all rams are activated and CT is sheared [8]. .....	26
Figure 1-16: Combined BOP rams [8].....	27
Figure 1-17: CT surface set up and rig up schematic [14].....	28
Figure 1-18: CT Roll-on Connectors [8]. .....	29
Figure 1-19: CT External grapple Connector [8].....	30
Figure 1-20: Dimple Style CT Connector [8]. .....	30
Figure 1-21: CARSAC HT CT Connector [8].....	30
Figure 1-22: CT Dual Flappers Check Valve [8].....	32
Figure 1-23: WBS when performing intervention operation with CT according to NORSOK D-10 [15]. .....	34
Figure 3-1: Example of Fish Hook well profile [22]. .....	40
Figure 4-1: CT Weight Indicator load [28].....	44
Figure 4-2: MWD Logs [28].....	45
Figure 4-3: MWD Resistivity Log [28]. .....	46
Figure 5-1: Flow chart to achieve a technically feasibility CTD project [24]. .....	52
Figure 5-2: Section view of well A-11 [25].....	54
Figure 5-3: 3D view of well A-11 [25].....	54
Figure 5-4: Section view of well A-14 [25].....	55
Figure 5-5: 3D view of well A-14 [25].....	55
Figure 5-6: Section view of well A-23 [25].....	56
Figure 5-7: 3D view of well A-23 [25].....	56
Figure 5-8: Section view of well A-26 [25].....	57
Figure 5-9: 3D view of well A-26 [25].....	57
Figure 5-10: Section view of well A-31 [25].....	58
Figure 5-11: 3D view of well A-31 [25].....	58
Figure 5-12: CTD drilling liquid design flowchart [27]. .....	59
Figure 5-13: CTD drilling foam design flowchart [27]. .....	60

Figure 5-14: Simulated graph for water in the casing flow regime [24].....	61
Figure 5-15: Positive displacement motor [34]. .....	67
Figure 5-16: Turbine motoe [34]. .....	68
Figure 5-17: Cased Hole Whipstock [37]. .....	71
Figure 5-18: CT weight load simulation indicating buckled pipe [38]. .....	73
Figure 5-19: WBS during CTD operation. ....	74
Figure 5-20: Example of P&A of TTDC wells [23]. .....	75
Figure 5-21: Time estimation using drilling & well estimator [25].....	77
Figure 5-22: Activity time estimation using drilling & well estimator [25] .....	78
Figure 6-1: Independet adjustable ribs [39].....	80
Figure 6-2: RSS motor [39]. .....	81
Figure 6-3: HydraSet™ CT Jar [41]. .....	83
Figure 6-4: Dynamic excitation tool -valve's plate position [45].....	84
Figure 6-5: Open clad thru clad [44]. .....	85

## Abbreviations

BHA	Bottom Hole Assembly
BHP	Bottom Hole Pressure
BHT	Bottom Hole Temperature
BOP	Blow out Preventer
CCL	Casing Collar Locator
CT	Coiled Tubing
CTD	Coiled Tubing Drilling
DG	Decision Gate
DHPG	Down Hole Pressure Gauge
DLS	Dogleg Severity
ECD	Equivalent Circulation Density
e-line	Electrical Line
FMI	Full-bore Micro Images
GF-A	Gullfaks-A
HSE	Health, Safety and Environment
HT	High Tension
ID	Inner Diameter
KOP	Kick off Point
LCM	Lost Circulation Materials
LWD	Logging While Drilling
MIT	Muti Finger Imaging Tool
MODU	Mobile Offshore Drilling Unit
MPD	Managed Pressure Drilling
MWD	Measurement While drilling
NCS	Norwegian Continental Shelf
OD	Outside Diameter
OHC	Open Hole Clad

P&A	Plug and Abandonment
PDC	Polycrystalline Diamond Compact
PDM	Positive Displacement Motor
PLUTO	Pipe Lines under the Ocean
POB	People onboard
POOH	Pull out of Hole
RIH	Run in Hole
ROP	Rate of Penetration
RSS	Rotary Steerable System
RSM	Rotary Steerable Motor
SCR	Slow Circulation Rate
TD	Total Depth
TTD	Through Tubing Drilling
TTDC	through Tubing Drilled and Completed
TTRD	through Tubing Rotary Drilling
UBD	Underbalanced Drilling
WBE	Well Barrier Element
WL	Wireline
WOB	Weight on Bit
XMT	Christmas tree



## Abstract

This report is carried out as part of Decision gate1 (DG1) feasibility study conducted for the possibility of commencing coiled tubing drilling to drill slim holes simultaneously with other drilling activities on Gullfaks A (GF-A).

A number of wells on GF-A platform has been closed and experienced oil production drop due to different reasons. However there are still small reservoirs with oil left in place which can be drilled through their mother wells to act as producer or injector wells in order to increase oil and gas recovery from this field.

This project is carried out to assess and gain extensive understanding of all activities so that one feasible solution is identified to meet the project objectives.

Coiled Tubing Drilling (CTD) is utilized first in early 1990s for drilling re-entry wells as this technique made it economically possible to drill inter-bedded formations. Thereafter, these have accelerated the use of coiled tubing (CT) as drilling application.

Technical and logistic challenges associated with CTD as well as drilling in mature area have considerable risks that indeed require steps of evaluation to properly understand the task so that prevention and mitigation measures can be set and overall risk picture can be evaluated to make the decision for initiating the concept and then the planning phase.

However, CTD operation in offshore environments is still not as widely used as on land operation and still needs in depth studies to evaluate its feasibility due to limited space and cost efficiency.

Utilizing previous experiences will enhance the study with lessons learned and positive practices done when drilling with CTD specifically on GF-A platform.

Performing CTD as independent operation compared to CTD conducted by utilizing drilling tower on the platform have completely different planning, and special attention must be taken in considerations regarding top side equipment that should to be identified during the feasibility and execution phase. The investigation of these points has made a significant contribution in the final conclusion of this study.

This thesis describes the CT as a well service tool that can offer different solutions for different applications. A general introduction to CT surface and downhole equipment supported with Figures is presented to allow better understanding for an inexperienced reader.

The CTD represents the core subject of this thesis and presented by first introducing the CTD as a relatively new drilling application with its opportunities and limitations. This is followed by case studies for similar operations held in Norway and from two different places around the world executed by two different operating companies.

Variables that impact the drilling operation are highlighted with a guideline to achieve the optimal drilling parameters so that one feasible solution can be met as intended by t this study.

As the well integrity importance is crucial for the entire well's life cycle, the well barrier schematics during drilling operation and proposed plug and abandonment plan are presented in this report.

The discussion has also covered the time and cost estimations as well as platform capacity with respect to deck space and people onboard capacity. The people onboard capacity made a significant impact on the final outcome of the feasibility study to perform CTD operation on GFA-A. The new technologies and comparison between CTD and conventional rotary through tubing drilling is outlined to highlight both strength and limitations for both applications so that future drilling operation can be carried out in an optimal way.

## Introduction

The technology of using CTD is proven as valuable method for the application of slot recovery in mature fields used to penetrate leftover reservoir not targeted in the main wellbore. One of the main limitations for this application is the high start-up cost, mainly for one well project [1].

The oil industry is continuously demanding for developing new technologies that in return improve safety and environments impacts and sustain the business strategy. Pushing new technologies is therefore needed to set new limits. Drilling with CT represents a radical change from the conventional way and is considered the key stone for re-evaluating the standard practice of well design taking into account the objectives of maintaining oil productions and minimizing impacts on humans and environments [2].

None directional drilling reflects the majority of CTD. In Canada, this application has been utilized for shallow gas wells and for drilling shallow water injector wells [3].

Drilling with CT using downhole motor has been practiced for more than 30 years for its primarily used to remove cement and scale depositions from wellbores [3].

By using directional drillings BHAs consisting of downhole motor and pressure-pulse operated orienting sub, bent sub, and steering device with a drilling bit, the first two directional wells were drilled from their original mother well using CTD technique. This has been carried out with 2in tubing size in USA. However, these two wells were economically unsuccessful, but it has proved the ability of using the CT for the drilling application [4].

Later CTD was utilized in land operation in Europe to re-enter two existing wells. Full CTD package is used in full range to drill and reach the horizontal section in the reservoir. The use of 7 conductor's electrical cable fed inside the tubing was utilized to control hydraulic operated orienting device [4].

This electrical connection providing telemetry communication has eliminated the need to change pumping rate in order to get the desired direction. By meeting drilling objectives, this operation has proved the capability of CTD technique to drill sidetrack sections and running liner casing as well as the ability to perform open-hole fishing operation [4].

Although, CTD operation is picking up worldwide, there is still limited experience and still considered as new technology. The main areas that are utilizing this technology successfully are Canada - Alaska (600 wells are drilled every year), Oman, Venezuela and Sharjah in United Arab Emirate. All of these areas are land operations except in Venezuela [5].

CTD has its advantages and limitations as well as the border line operation areas. These advantages can be listed as below [5].

- Fast tripping in and out of the well (x4) (no need to make connections).
- Drilling and circulating under pressure by using pressure control equipment at surface.
- Through tubing drilling (TTD)
- Continuous telemetry communication with downhole tools by continuous circulation or through electrical or fiber optic lines.
- Movable.

The limitations for CTD are as list below [5]:

- Pipe rotation is not available.
- Not able to drill long horizontal section due to high frictions and possible CT buckling.
- Limited pull force at surface due to limited tubing strength.
- Hole cleaning limitations due to limited surface pumping pressure and no CT rotation.
- Limited availability of WOB.
- Tubing operational life due to fatigue and stress exposure.
- High maintenance cost (for example: the need to replace CT due to relatively short tubing life time).
- Limited staff experience.

CTD is considered to be none suitable to be used for the following drilling operations as listed below [5].

- Drilling excessive long reach wells (>16 000ft).
- Drilling 8.5in or bigger hole sizes.

- Drilling through unstable zones because the pipe rotation is not available when drilling with CTD. However this can be overcome by using open hole clad (OHC) as described later in this report.

The CTD is not intended to replace the conventional way of drilling directional and horizontal wells. This application is mainly used for the following reasons [6]:

- Drilling in areas where noise intensity must be kept to minimum and well control must be granted.
- Drilling with underbalanced application where approval is not possible for such operation using conventional drilling technique.
- Drilling re-entry wells in offshore environment in case the drilling derrick is not available on the rig and installing a work over rig is very expensive comparing to drilling with CT.
- TTD to minimize the project cost by keeping the upper completion in place.

The objective of this thesis is to assess the feasibility of performing CTD on GF-A by assessing the technical feasibility and going through different parameters affecting the drilling operations. This will be done by extracting previous experiences, lessons learnt, familiarizing with existing and new technology to drive the project to be feasible. However, the logistic aspects related to the platform and people onboard capacity have its own impact on the final feasibility outcome. Statoil is utilizing through tubing rotary drilling (TTRD) for drilling re-entry wells but this technique dictates occupying the drilling derrick while CTD can be utilized as standalone operation with modifications that must then be performed on the platform.

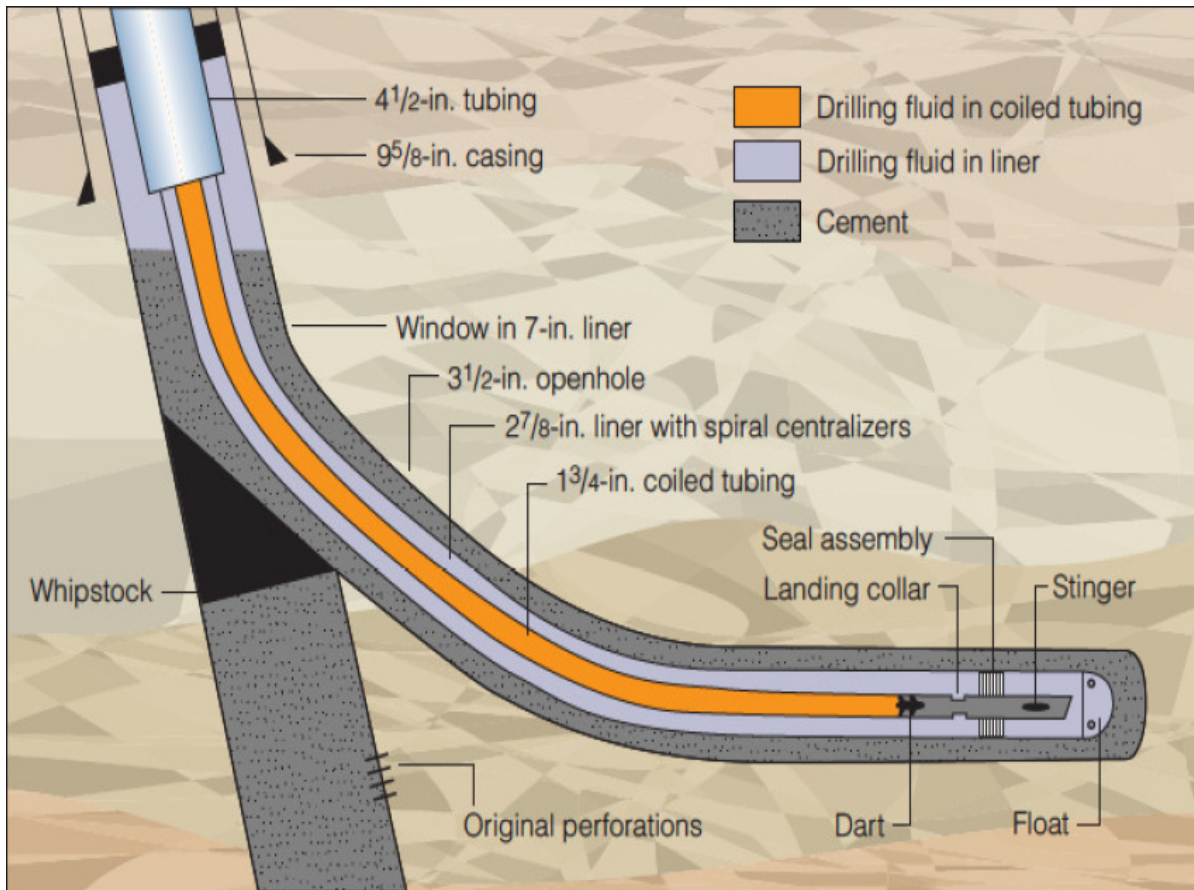


Figure 0-1: CTD well's design [13].

## 1. Coiled tubing (CT):

The term “Coiled Tubing” refers to a long jointed pipes (no need to make connections) spooled on a reel. It is available in different sizes of outside diameter (OD). The concept of using “continuous long steel tubing” as so called today coiled tubing in well services operations is recorded in patent rewarded in Sep. 1951 [7].

Coiled tubing OD ranges from ½ in to 6-5/8 in. Figure 1-1 shows the evolution of coiled tubing size as a function of time [8]

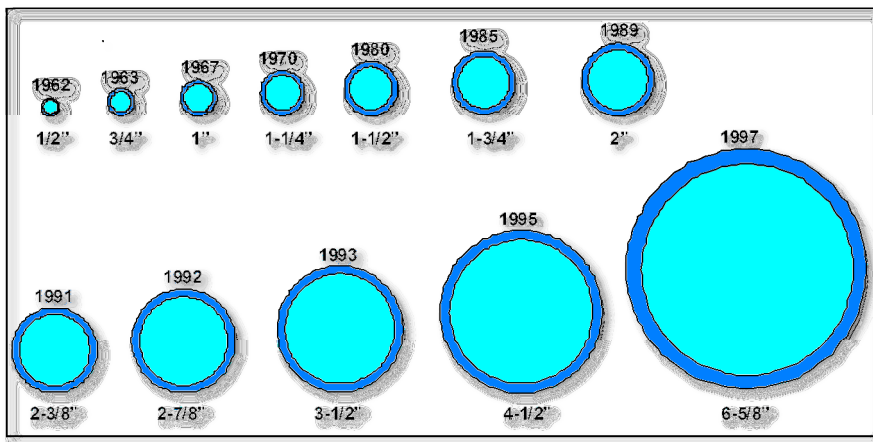


Figure 1-1: Evolution of CT sizes [8].

### 1.1 History:

CT was developed in early 1960’s as a well service tool with intention to be used in live wells. Other factors have also had the impact to continuously developing of CT such as time speed and economic benefit from CT applications.

The origin of CT goes back to 1944, when British engineers worked on developing long, continuous pipelines to be used as fuel transporting pipeline from England to the European Continent for Allied armies’ supplies. The project was named "PLUTO" as abbreviation for "Pipe Lines under the Ocean" which included the manufacturing and laying the pipe across the English Channel. This has later been utilized to be one of the key tools for well service operations [10].

For well interventions operations, CT gives advantages over normal wireline (WL) operation by the ability of pumping through it and also it can push the downhole equipment rather than being completely dependent on gravity [11]

The CT can be utilized without the need to kill the well and therefore, avoiding damages induced to the formation and also has the environmental advantage because of the small footprint [11]. However, footprint size is normally a disadvantage for offshore locations and considerations must be taken when planning CT operation on offshore installation due to footprint size occupied by CT surface equipment needed to commence normal CT operation. In general, CT uses the rig derrick on offshore platforms and special intervention tower when the derrick is not available. For deep water wells, CT can be conducted with mobile offshore drilling unit (MODU), Intervention vessel or fixed platform that can support the riser's weight and where the returns can be handled onboard. This limitation is not the case for WL where operations can be done with light intervention vessels. However, trials are being made to handle CT on intervention vessels [12].

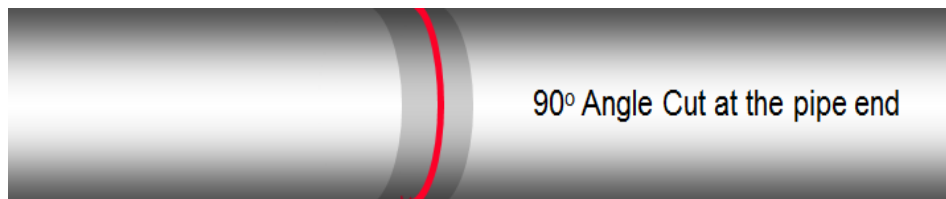
## **1.2 Coiled tubing Equipment**

### **1.2.1 The Coil**

There are two types of manufacturing process forming the coiled pipe as described in the following [8]:

- 1- Pipes jointed together with "Butt Welding".
  - "Butt welding": 90° pipe ends pipes welded together forming long pipe. The welded piece is "heat affected zone", and the tubing thickness is reduced in the welding area resulting to be subjected to fatigue bending.





**Figure 1-2: CT Butt Welding [8].**

- 2- Long continuous steel strips jointed together by “Bias welding”. These stripes are folded at manufacturing plant forming pipes which will be welded together by bias welding [8].
- “Bias welding”: 45° strip ends welded together. The welded area is heat treated to give it the same properties as the rest of the pipe and fatigue life will be the same all over the pipe.



**Figure 1-3: CT Bias Welding [8].**

These steel strips are passed through:

- Rollers to form the pipe
- HFI ERW, high frequency induction electric resistance welding
- None destructive tests
- Heat treatment
- Spooled on take up reel

Manufacturing process steps are shown in figure 1-4 below.

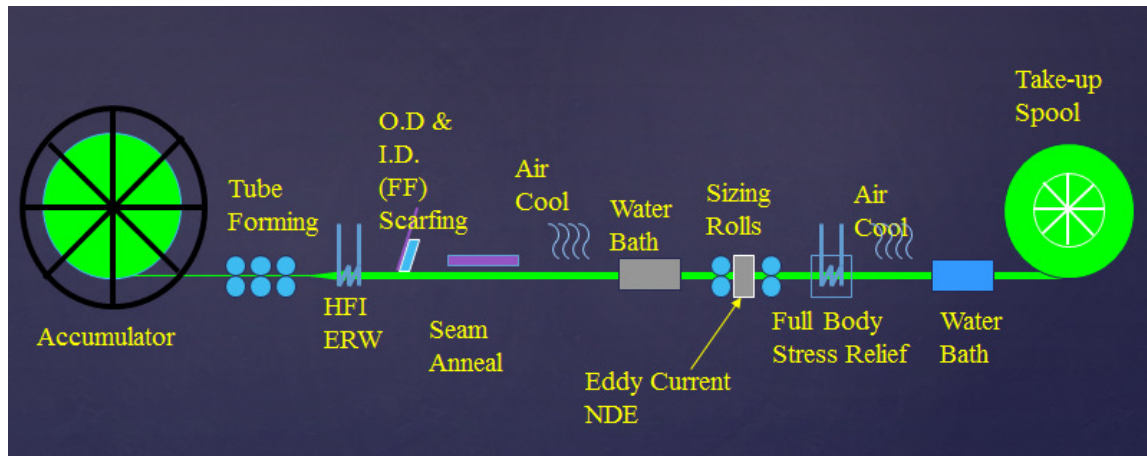


Figure 1-4: CT manufacturing process [8].

The following design, construction and selection must be taken is consideration when CT is used as well barrier element according to Norsok D10 [15]

1. Dimensioning load cases shall be defined and documented
2. The Minimum acceptable design factors shall be defined (80 % of minimum yield). Estimated effects of temperature, corrosion, wear, fatigue and buckling shall be included in the design factors.
3. Coiled tubing should be selected with respect to
  - Yield strength
  - Pump rate
  - Length
  - Weight
  - Burst pressure
  - Collapse pressure

### 1.2.2 Injector Head

It is the upper most equipment rigged on the top of the well. The Injector head is hydraulic driven with capacity of 10k – 200k lbs. It consists of [8]:

- Chains with replaceable gripper blocks for moving tubing in and out.

- Traction cylinder to provide tension on the chains.
- Brakes
- Weight indicator used to monitor forces applied on the tubing during CT operations for both pipe light (snubbing forces) and pipe heavy (weight of CT in the well).
- Gooseneck to provide curved path for coil between injector head and CT reel.

The injector head is used to move the CT in and out of well by using two counter-rotating chains. These chains with gripper blocks attached to them provide grips by means of applying pressure on the tubing. This gives the injector head three main functions as following [8]:

- Provide the force needed to overcome surface pressure and frictions to snub the tubing into the well.
- Control CT speed when tripping in and out of hole.
- Provide the force needed to pull CT out of hole and support CT weight in the well.

The design of curved shaped gripper blocks allows covering the entire outside area of the coil to give the friction needed to provide excellent grip. While the tension forces are needed on the chains to give proper grip on CT is maintained using traction cylinders located inside injector head [8].



Figure 1-5: CT Injector Head and Gooseneck [8].

The Slack created on the chain outside (not in contact with CT) due to high stretch on the chain formed by the pushing forces is removed by the use of outside chain tension cylinder [8].

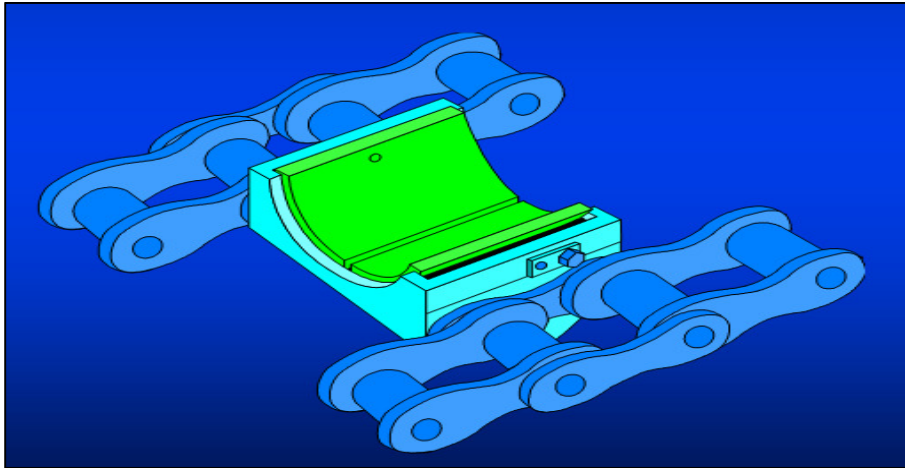


Figure 1-6: CT Grippers and Injector Head's Chains [8].

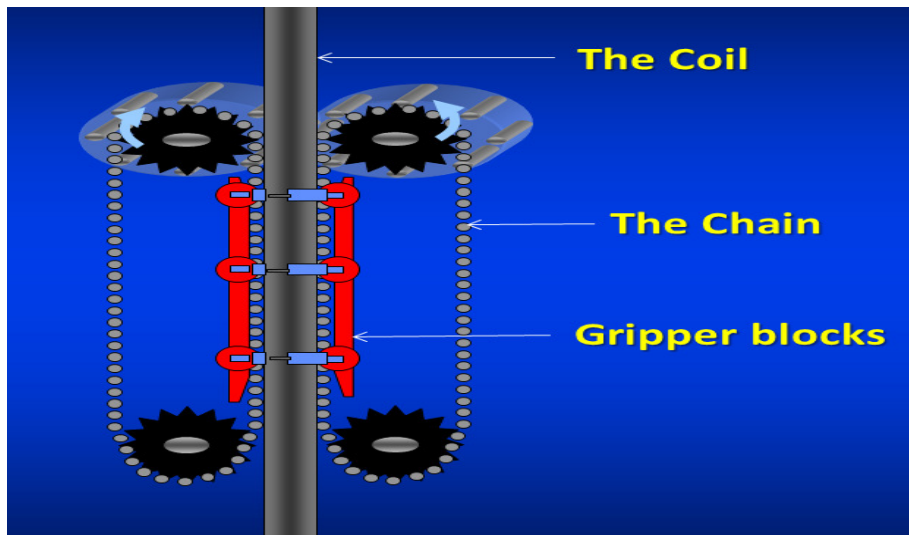


Figure 1-7: CT Gripper engaged to the CT while running in hole [8].

The gooseneck controls the CT bending radius which affects CT fatigue life. It also dictates the fleet angle between the reel and injector head. It also contains a number of rollers that support CT while moving [8].

### 1.2.3 The Reel

The reel provides storage place for the desirable length of the coil with ability to pump liquids and nitrogen during operation while running in hole (RIH) and pulling out of hole (POOH). The reel power capacity is enough to spool and un-spool CT on the drum while additional pull forces from the wellbore side are provided by injector head [8].

But, the reel motor can give necessary surface tension needed to properly spool CT in layer forms on the drum.

The reel is considered as the limitation for CT due to its weight when exceeding the limits for offshore rig cranes and may be too heavy for offshore structural capacity per square area. However, the reel can be located on separate vessel located beside the platform [8].



Figure 1-8: CT reel [8].

The ball launcher and pumping lines connection are part of the reel. The ball launcher simply gives the accessibility to utilize a ball that is pumped during the operation whenever required [8].

Dropping the ball through the CT is done with intention to seal a ball seat bore located within bottom hole assembly (BHA) in order to route the pumped fluid through a valve located above the BHA to prevent wearing in down hole motor.

The reel also contains the depth control system in which indicates the length of tubing ran in the well and helps to safely bring the BHA back to surface. The depth system has two wheels and a software used to convert the wheels revolutions to linear distance and running speed [8].

### 1.2.4 Pressure control Equipment

#### 1.2.4.1 Stripper (Stuffing Box)

It is located under injector head providing primary pressure control over the well in operation by utilizing seal around CT when running in and out of hole.

Normally two stuffing boxes are used for CT rig up and the upper one is used as primary barrier element. The lower stripper is a backup used to seal the well while repairing the upper one if needed [8].

The side door stuffing box gives the possibility to change sealing elements whenever required during the operation while tubing is passing through it.

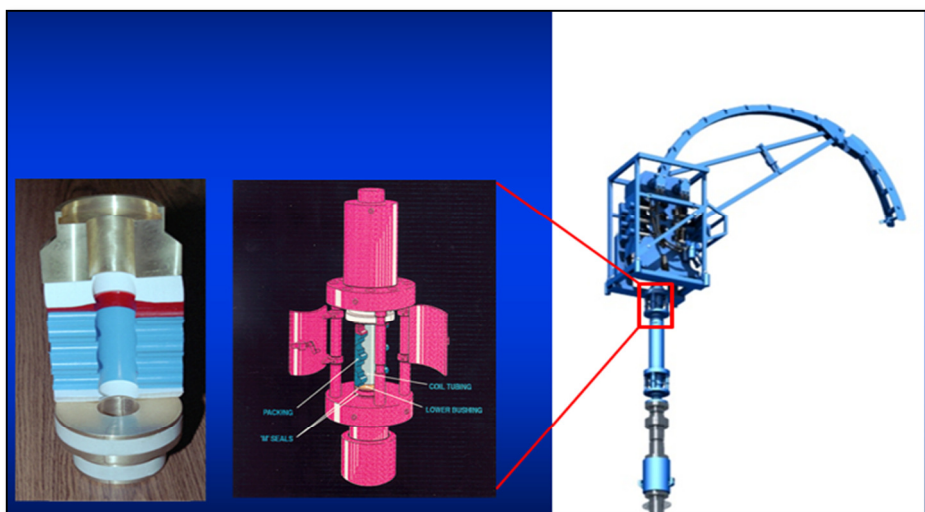


Figure 1-9: CT Strippers [8].



### 1.2.4.2 Blow out Preventer (BOP)

The BOP in connection with stripper makes up the pressure control stack. All equipment's are pressure rated and tested to maximum wellhead pressure and temperature and compatible with different fluids.

There are three different types of BOPs with regards to numbers of rams. They are dual, triple and quad rams BOP.

The figure below is for quad rams type BOP with kill port and equalizing valves illustrated [8].

*A kill inlet port shall be located between the shear/seal ram and the pipe ram. It shall be possible to pump heavy fluid through the CT string after the BOP has been activated.*

[NORSOK D-10 R3]- Table 14.

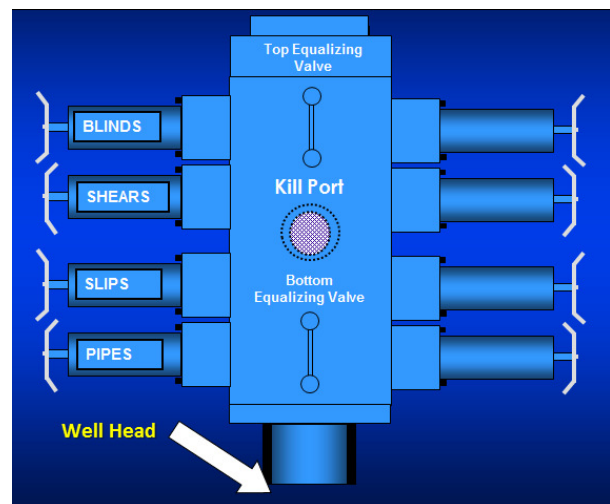


Figure 1-10: Quad rams - CT BOP [8].

As illustrated, the kill port provides access to the wellbore below blind and shear rams to allow pumping the kill fluids for killing the well after the CT is sheared.

### 1.2.4.3 Blind ram assembly

This ram is used to close the well by sealing against each other with front seal when the CT is not presented in between. Therefore, this ram is activated at last step of closing the BOP rams. It also contains the pressure from the back of the ram body by rear seal element [8].

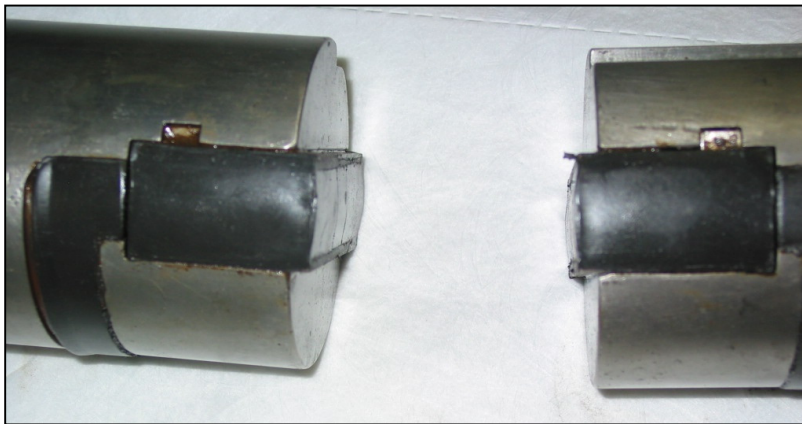


Figure 1-11: CT BOP's blind rams [8].

#### 1.2.4.4 Shear ram assembly

It uses metal blades to cut the CT in case of emergency so that it will be possible to secure the well by closing the blind rams. It's built from high ductile material to prevent cracks while shearing. The blades are proved for one cut [8].



Figure 1-12: CT BOP's shear rams [8].

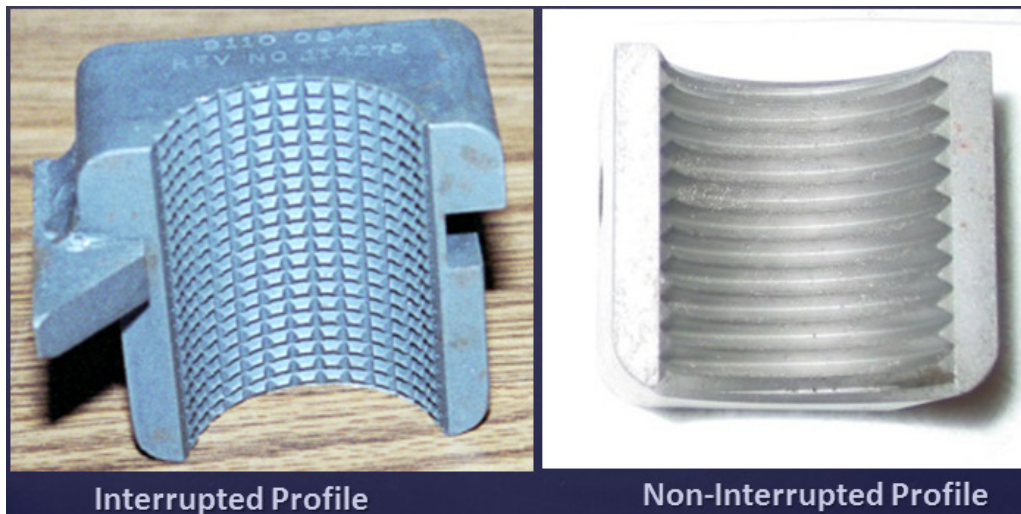
When blades are worn out it will act more like crushing than shearing, the cut is considered good when still having access to coil inner diameter (ID) [8].



#### 1.2.4.5 Slip ram assembly

This ram is utilized to hold CT in place and prevent it from movements. It holds up to yield strength limit for CT. There are two types of slips based on holding profile, Interrupted and non-interrupted.

It is preferred to use the interrupted profile rams due to less damages induced when they are acting against CT [8].



**Figure 1-13: CT BOP's Slips types [8].**

#### 1.2.4.6 Pipe ram assembly

This ram is used to seal around CT and secure the well by isolating well head pressure. The tubing is moved to the center of the ram by the tubing guide to allow proper sealing affect provided by the pipe rams [8].



Figure 1-14: CT BOP's Pipe ram assembly [8].

The figure below illustrates quad BOP when rams are operated.

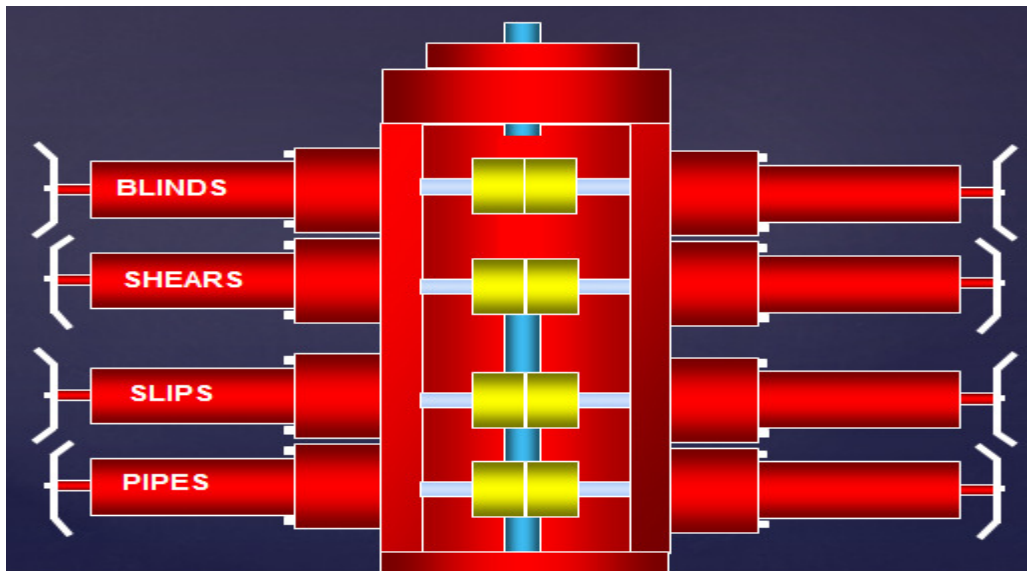


Figure 1-15: Quad BOP all rams are activated and CT is sheared [8].

The CT BOP is available also with 3 and 2 rams. The pipe and slip rams are combined in one ram in a two rams BOP as well as shear and seal rams.

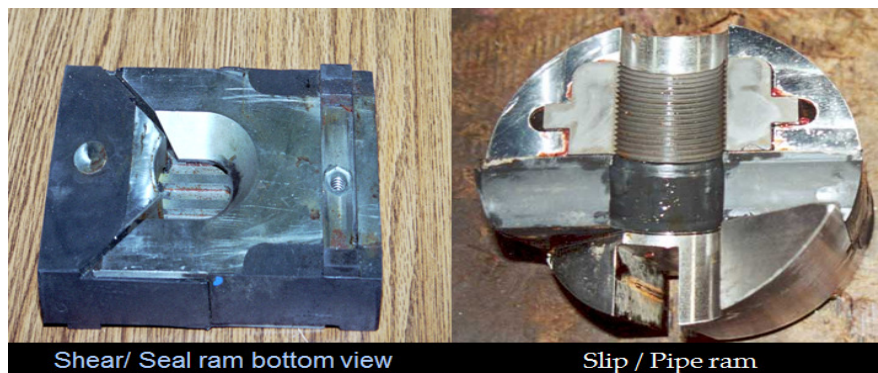


Figure 1-16: Combined BOP rams [8].

#### 1.2.4.7 Safety Head

*This device is installed below CT BOP above the Christmas tree (XMT). Its primary function is “to prevent flow from the well bore in case of loss or leakage in the primary well barrier at the surface. It shall be able to close in and seal the well bore with or without CT through the BOP. The safety head is the upper closure device in the secondary well barrier. It shall be documented that the shear/seal ram can shear the CT and seal the wellbore thereafter. If this cannot be documented by the manufacturer, a qualification test shall be performed and documented”*

NORSOK D-10.

### 1.2.5 CT Power Units

The CT power unit is operated with hydraulic power. The mechanical power is transferred to hydraulic power which will operate different systems producing mechanical power. For offshore location, there is a dedicated electro-hydraulic power unit to drive the hydraulic pumps that operate the CT equipment [8].

The dynamic equipment such as injector head, and reel motor are driven by high volume and low pressure fluid which is provided by the power unit. Moreover the power unit provides low volume with high pressure hydraulic fluids to operate the static components such as strippers and BOP [8].

### 1.2.6 CT control cabin

The cabin is accompanied with control system that uses electrical signals to remotely control the hydraulic driven system and eventually injector head reel and BOP. Pressure can be monitored via pressure gauges mounted inside the cabin. The cabin is also used for real time data acquisition that assists the CT operator to successfully perform the operation. These data are but not limited to running rate, injector load and pressure as well as fluid pumping rate [8].

Figure 1-17 illustrate the full setup of CT and pressure equipment's rig up.

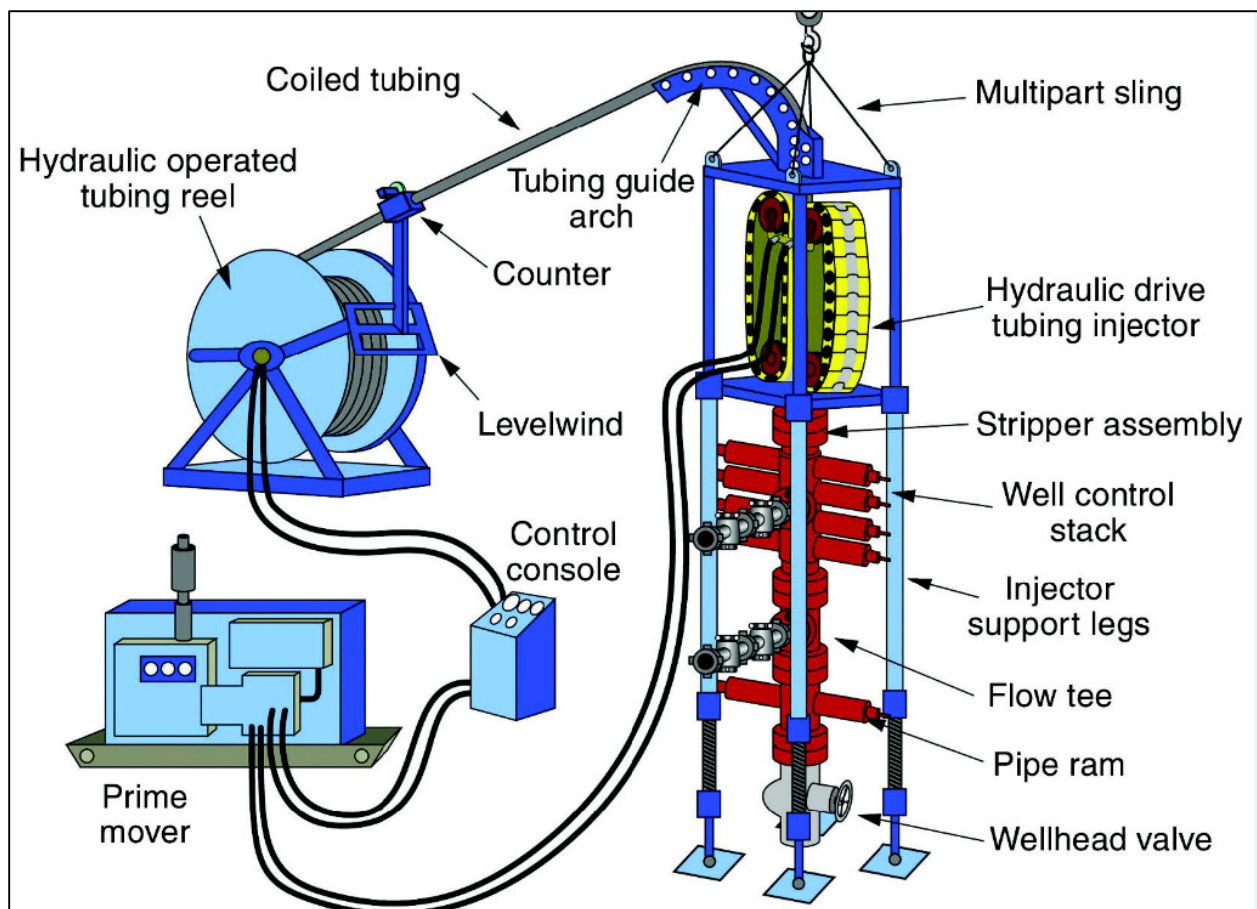


Figure 1-17: CT surface set up and rig up schematic [14]

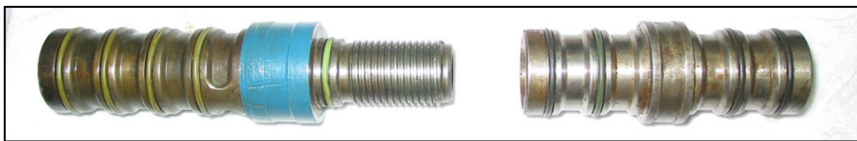
## 1.2.7 CT Tools

The key for successful operation commenced using CT is the use of correct downhole tools to achieve the job objectives. Various tool types with specific operational details are available for different service categories such as the following [8]:

### 1.2.7.1 Connectors

The purpose of connectors is attaching BHA to the end of the coil. There are different types of connection categorized based on their connection mechanism [8].

- Roll-on connector used for small tool strings with no torsion forces to be applied during operation. It has the same OD as the coil inner diameter (ID). This connector has a number of groves that attach and seals across the coil's ID. It can also be used to splice two coils for spooling purposes on surface only [8].



**Figure 1-18: CT Roll-on Connectors [8].**

- Connector with External grapple

This is the heavy duty connector used for operations such as fishing and drilling. It has bigger OD than the coil with external seal. The coil must be cleaned prior to installing this connector.

The grapple is strengthened by applying tensile forces. This is due to a reduction in grapple OD/ID and therefore biting more on the coil. However, the grapple must be changed after every run. It is not rotatable because the grapple can be disconnected when torque is applied [8].



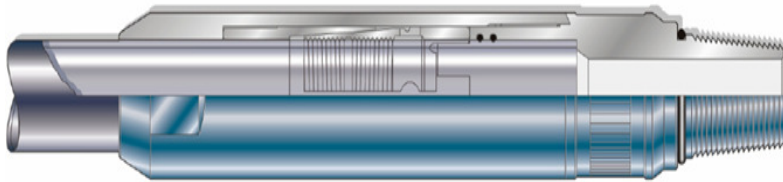


Figure 1-19: CT External grapple Connector [8].

- Dimple Style CT Connector

This can be used for different sizes of coiled CT. It has bigger OD compared to roll-on connector with higher tensile and torsion strength. It is easier to attach to the CT than the two previous types and this connector can be reused [8].

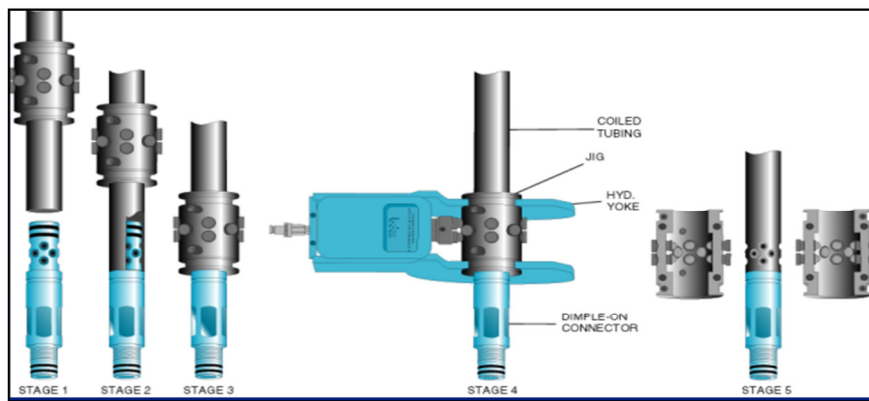


Figure 1-20: Dimple Style CT Connector [8].

- CARSAC High Tension (HT) CT Connector

This connection is a high torque and tension connector. Its “self-aligning” and used when tool string is not possible to be rotated [8].

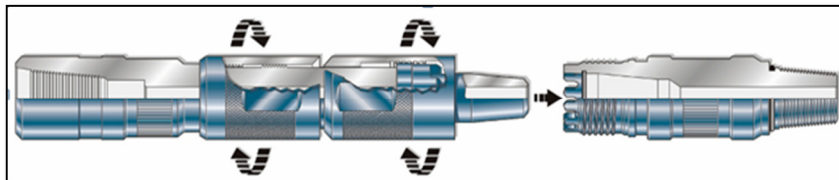


Figure 1-21: CARSAC HT CT Connector [8].

### 1.2.7.2 CT Valves

They are considered to be critical in the CT BHA. The valves are used mostly in all CT operations with few exceptions. Different types of valves are available as listed in the following [8].

- Check valve

This valve is a primary well barrier element (WBE) when CT is in operation according to NORSOK D-10.

1. *The check valves shall be designed to withstand all expected downhole forces and conditions.*
2. *The pressure rating shall exceed the maximum operating pressure.*
3. *The check valve shall be provided with dual seals in the bore and provide internal and external sealing on the connections towards the CT string.*
4. *Provisions shall be made for pumping balls through the CT check valves.*

However, the check valve functions to stop possible flow in upward direction through the coil in case of pump failure. Different types such as Dart and flapper check valves are available. The flapper valve is preferred in most operations because it allows passing of ball in which is used to activate other tools in the tool sting such as the disconnect sub. The flapper is positively sealing for both low and high temperature [8].

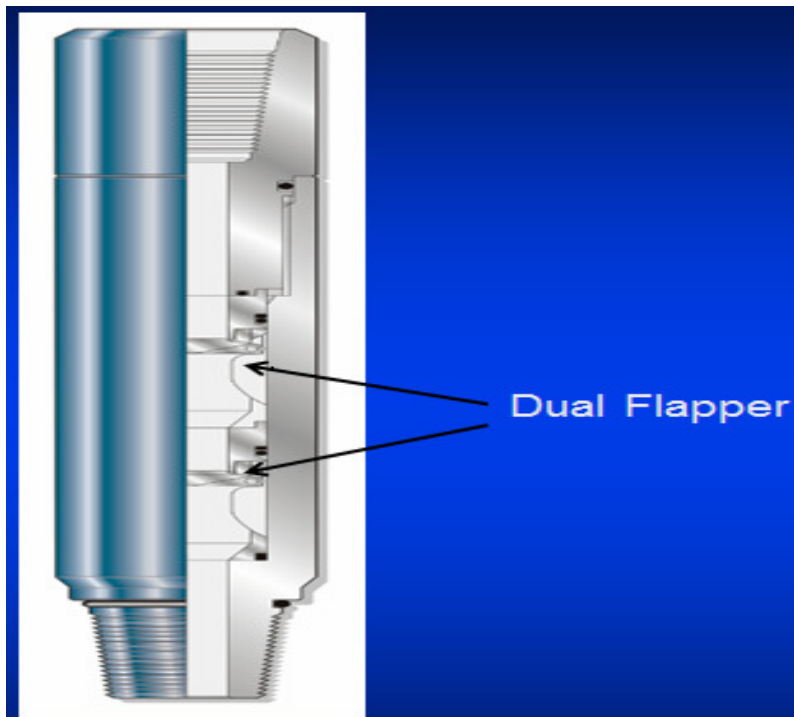


Figure 1-22: CT Dual Flappers Check Valve [8].

### 1.2.7.3 Dual activated circulation sub

It is used to re-route the fluid flow and hydraulically isolate the tools below in which will prevent wear on down hole motor. It is activated by using drop ball that seals against the ball seat. Followed by applying pressure, this will lead to shearing of mounted shear pins in which will lead to open the circulation port and that will allow higher circulation rate. Other types are activated by bursting shear disk but this type is not actively isolating the tools below. However, this sequence is done upon completion of the operation so that is possible to bypass the motor when the motor no longer needed to complete the operation [8].



#### 1.2.7.4 Disconnects

This tool is used when BHA OD is bigger than CT OD. It is used to release CT from the BHA in a controlled way in the following scenarios [8].

- To release CT from stuck tool.
- Installing an assembly in the well. For example, sand control screen.

It is activated with a ball that moves down the dogs holding insert when needed differential pressure is applied and safely release the CT from stuck BHA.

### 1.3 Well Barrier Schematics (WBS)

The following, figure 1-23 represents the WBS during CT operation as referenced in NORSOK D-10

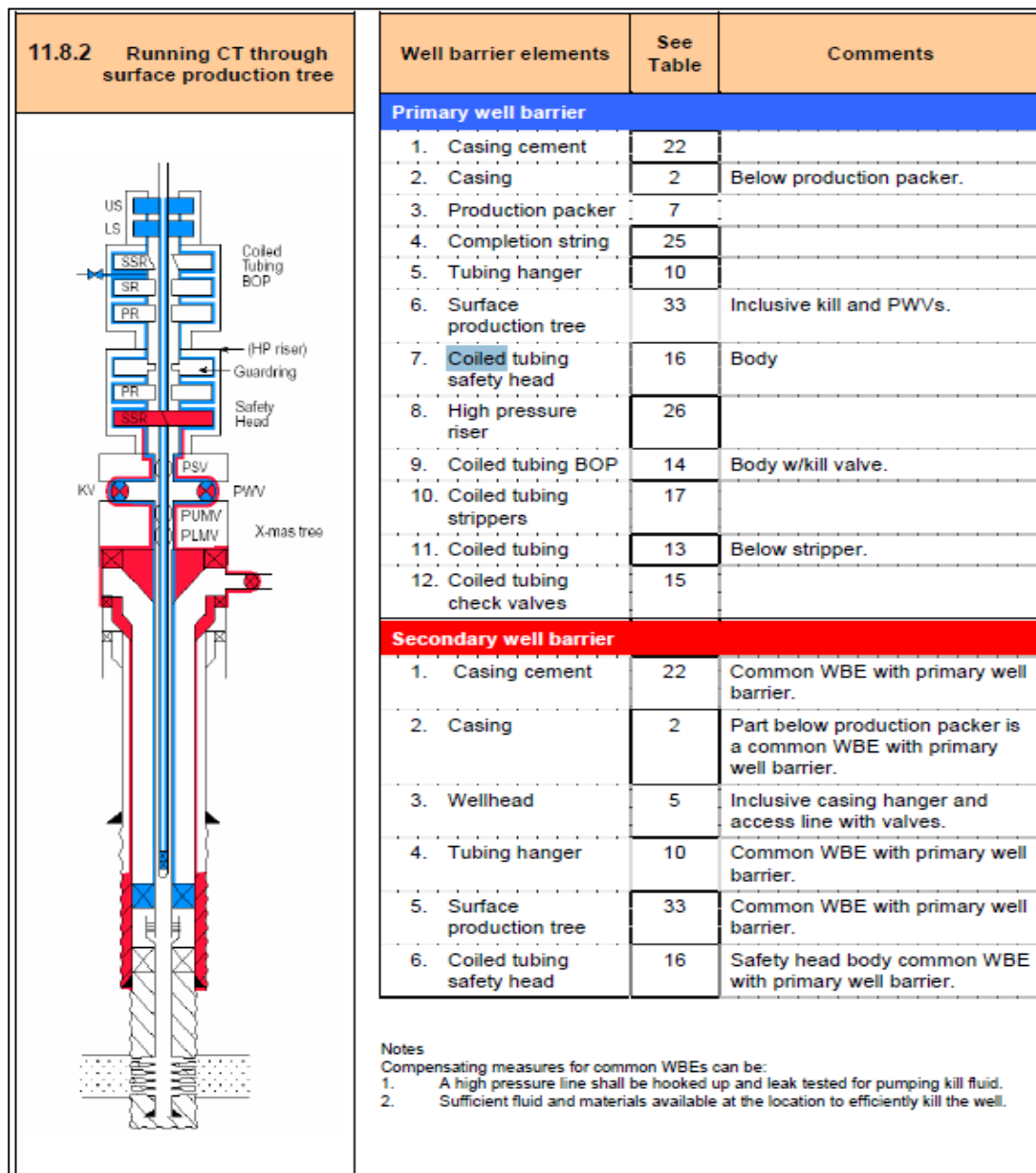


Figure 1-23: WBS when performing intervention operation with CT according to NORSOK D-10 [15].

## 2. CT Applications:

CT application can be divided into pumping and mechanical applications as two main categories depending on activity performed by CT. However, a variety of services is carried out using CT as illustrated in the table below [14].

**Table 2-1 CT Applications**

Pumping	Mechanical
Sand fill removal from wellbore	Setting plugs and packers
Formation fracturing and acidizing	Perforation, logging
Scale and wax removal	Fishing
Setting gravel pack completion	Mechanical scale removal
Tubing cutting using jet fluid	Mechanical tubing cutting
“Pumping slurry plugs”	Operation slide sleeve.
Well unloading	Drilling

### 2.1 Sand fill removal

Sand removal operation has different names, such as “sand washing”, “sand jetting”, “sand clean out” and “fill removal” [3]. This operation aims to regain productivity of the well by removing sand obstacles in which acts against fluid flow in the wellbore. Moreover, clean out will allow free passage for other service that might be run such as WL and other service equipment. The clean out is done by pumping fluid through the coil that is lowered in slow motion when reaching the top of the fill. The jet nozzles tool attached to end of the CT will loosen the sand particles in which will be lifted up with help of circulation current. Downhole motor can be used as aid for the surface pump to increase cleaning efficiency [8]. The Tornado tool is a new technology designed product which has been developed by Baker Hughes. The jetted fluid can be pointed down and break the surface of the compacted sand in the wellbore. It can also be pointed in upward direction giving the possibility to drag filling materials and/or sand while POOH [17].



**Figure 2-1: Sand / Fill clean out - Tornado tool [16]**

Sand clean out is the oldest application of coiled tubing and represents 30% of all CT operations. However, 22% of clean out runs fail due to losses and sand fall back [16].

Reverse circulation can be done by pumping down the tubing and allowing returns through the CT. This is normally done when expecting large amount of fill accumulated after a fracture operation. Reverse circulation is appropriate only with wells which are dead with no need for active well control equipment [3]. Furthermore, large annulus size represents a challenge for hole cleaning in which laminar flow is expected and can cause settlement of sand particles that will lead to unsuccessful cleaning operation [8].

## 2.2 Well Unloading and well start up.

This application is used in wells with overbalance condition where pressure exerted from hydrostatic column is higher than reservoir pressure at static situation. Therefore, it is used to bring the well into production [8].

Pumping down gas (nitrogen) will reduced bottom hole pressure (BHP) and allows reservoir fluid to flow naturally at certain conditions based on reservoir pressure, fluid mixture percentage

which will result in average well fluid density and the flow rate. The unloading job is designed based on well performance which dictates the optimized unloading depth and pumping rate [8]. This process can also be used to get downhole representing fluid sample (gas, water, and oil) and considered to be simple from an operation point of view with limited equipment and personnel needed to run this operation [8].

### 2.3 Formation Fracturing/Acidizing

Coiled tubing can be used to perform formation fracturing and reservoir stimulation operations with advantages of accurately positioning treatment fluid at the desired depth [19]. The use of specially designed BHA for this purpose will isolate the interest zone with dual packer elements tool and successful treatment throughout the formation can be achieved uniformly. Multiple treatments can be also made on single run to stimulate pre-perforated zones by using dual packer elements tools [19].

Initially, this has been done by pumping the treatment fluid down the tubing without ensuring fluid flow to the desired formation.

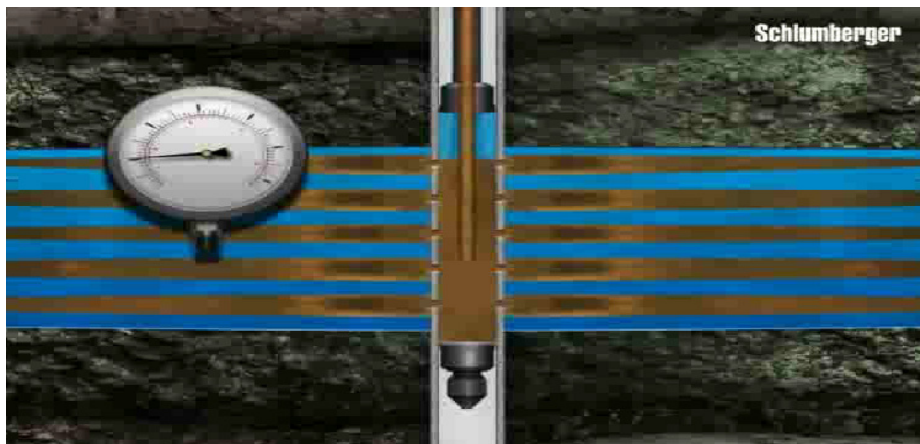


Figure 2-2: Formation fracturing using dual packer tool [19].

### **3. CTD History on Gullfaks A:**

GF-A drilled two wells in the past using CTD application. These two wells are the first drilled wells with CT on Norwegian Continental Shelf (NCS) in 1995/96. The main objectives of the project were to increase recovery from the Brent Sandstone by draining and achieving better understanding of the reservoir. The second objective sat to prove the use of TTD utilizing the technology of CTD so that other Statoil license areas could benefit from the accumulated experiences [20].

The well A-10, was drilled and completed in 40 days while the second operation on A-19A lasted for 75 days due to technical challenges associated with over-pressurized shale within the Ness formation. This resulted in wellbore collapse and loss of the well on two occasions. Therefore; the first two sidetracks (A-19A and A-19AT2) were plugged back and the third sidetrack (A-19AT3) was successfully drilled and completed [21].

Statoil had no available experiences with CTD within its organization. Gathering experience was done through visiting oil and service companies in Europe and USA to build the competences required for designing and planning the CTD programs [21].

#### **3.1 34/10- A-10**

The KOP was placed within the same pressure regime as the entire side tracked section. The positioning was based on avoiding milling of casing collars and centralizers as well as assuring a suitable build up rate for well trajectory control [20]. However, drilling the section was done with maximum of 25° /30m (considered very high) of dog leg severity so that it was possible to run standard liner [21]

The cemented liner completion was chosen to isolate penetrated water flooded and gas bearing sand whilst the pay zone was perforated in underbalanced condition and CT conveyance is used [21].

### 3.1.1 Rig up

This well was drilled with 2 3/8" CT from the drilling tower which was not in operation during CTD operation that gave benefits of using the rigging equipment. However, the injector head and strippers were rigged above the drill floor and the CT BOP was placed under [21].

### 3.1.2 Pre drilling preparations

Primarily, the minimum restriction in the well was the 3,687" ID nipple profile while the required was 3,8". The detailed operation included cutting and dropping the tail pipe to give access to the wellbore [21]. This has been done prior to bullheading two well volumes of heavy fluid due to enforce H<sub>2</sub>S present in the well into the main reservoir. The mother reservoir was then isolated by setting a mechanical plug [21].

### 3.1.3 Milling Exit window

"Baker Retrievable through Tubing Whipstock" was sat and high side oriented using SLB VIPER BHA<sup>1</sup>. The GR tool with the setting BHA was used for active depth control accuracy prior to setting the Whipstock. Seven runs were done to successfully mill the exit window.

The lessons learnt from this step can be listed as in following [21]:

- Exclude the jar/ accelerator from the milling BHA to avoid the jar activation at high pressure which will lead to excessive weight on bit (WOB) and eventually stallout.
- Experience recommends of setting the high side of Whipstock to the left to compensate for rotation movement induced by high torque applied from the milling bit.
- Utilize Casing Collar Locator (CCL) for correlation purpose to avoid being purely dependent on flagging the CT at surface which led to poor depth control during milling operation.

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<sup>1</sup> Reference is made in Appendix A

### 3.1.4 Drilling in Openhole

The well was drilled using VIPER tool<sup>2</sup> that had an orienting sub giving a continuous monitoring of well direction while drilling. This resulted in drilling almost straight tangent section and avoided the snake shaped wellbore when using conventional steering tool [21]. The whole section was drilled without encountering problems with planned rate of penetration (ROP) and no high dog leg severity (DLS). However, the total depth (TD) of the well was set 15m higher than planned, because of the risk of differential sticking; sliding down the CT with gradual pumping became impossible and also due to no progress in active drilling was observed [21].

### 3.2 NO 34/10-A-19

This well has also gone through series of preparations same as A-10 prior to start of CTD operation. Milling of scale accumulated in 7” liner and running a caliper log to verify the tubing condition were done before isolating the mother reservoir [21].

According to reservoir and geological requirements the target formation dictated the exit point to be from existing completion which resulted in deviation of 125 degrees and then followed by “fish hook” well profile. This was the “worldwide first” as this well trajectory had never been drilled using CT before [21].

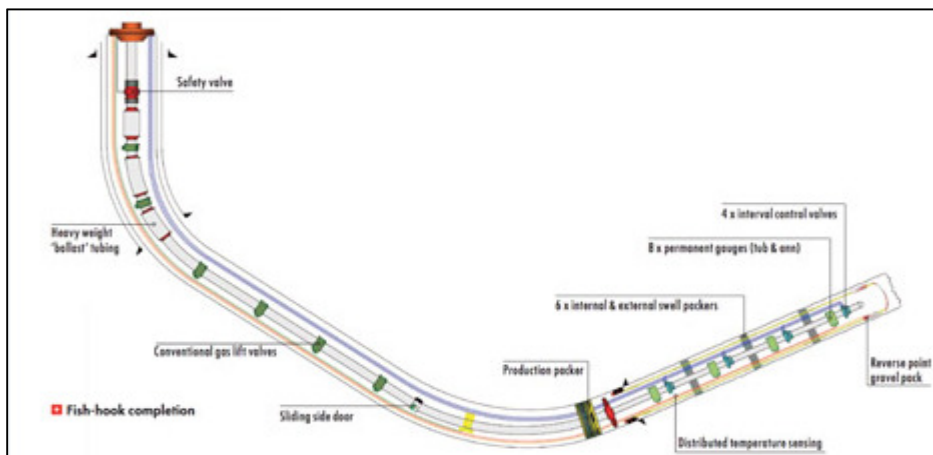


Figure 3-1: Example of Fish Hook well profile [22].

<sup>2</sup> Reference is made in Appendix A



## Master Thesis

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Worth mentioning here is that the first two sidetracks encountered collapse of over-pressured shales within the Ness formation which led to plugging and a need for a third sidetrack (A-19AT3) which was drilled and completed successfully. All sidetracks were drilled with high density mud weight resulting in a relatively high overbalance to suite pore pressure varieties in the Tarbert and Ness formations. The high annular fluid velocity achieved while drilling coupled with strict schedule of wiper trips resulted in good hole cleaning. Differential sticking was eliminated by using low solids mud design [21].

## **4. Experience from other oil companies:**

### **4.1 Terengganu Offshore – Malaysia**

#### **4.1.1 Introduction**

PETRONAS Malaysia has nominated a batch of wells in offshore Terengganu fields to the use of 2 ¾ in BHA in combination with 3 ½ in CT for the CTD project in 2011. Feasibility evaluation highlighted challenges related to the use of 2 ¾ in BHA to drill through 3 ½ in completion, setting the whipstock, milling the exist window through single and double casings and drilling approximately 915m from the Kick off point (KOP) as well as the drilling through a fault [28].

Comprehensive studies were carried out during feasibility and detailed planning phase aiming for successful operation to target leftover oil that potentially could increases the overall oil production. Thus, this project was planned to utilize wells that were suspended in the 1980s due to low production rates [28].

The platform needed some preparations prior commencing this project represented in modifying the crane for higher capacity and prepare the platform for the big and heavy CT equipment.

Challenges were addressed at the planning stage and the prevention and mitigation measures were identified for the related CTD issues as listed in the following section [28].

#### **4.1.2 Wellbore Stability**

The depleted reservoir pressure (~0.8 sg) and the fault presence within the well trajectory needed special attention to manage the risk of potential of lost circulation. The drilling operations were successfully conducted with mud weight designed in a range of 0.89 – 0.91 sg, and Equivalent Circulation Density (ECD) maintained to be between 1.15 – 1.18 sg with 250 ltr/min the flow rate. Surface back pressure was applied when pumping was stopped so that downhole pressure was kept the same as pressure given by ECD. However, Lost Circulation Materials (LCM) with “10 lb/bbl” concentration were maintained in the drilling mud for the purpose of strengthening

the formation. This together with controlled ROP resulted in drilling through the fault where no issues related to pressure and losses were experienced [28].

#### 4.1.3 Hole Cleaning

The hydraulic performance during the drilling operation confirmed a good hole cleaning efficiency by maintaining the ROP at 5m/hr with average annular velocity of approximately 90m/min at 250 ltr/min flow rate. The mud was designed to maintain optimal cuttings lift capacity which was monitored by comparing the theoretical volume of the drilled rocks against the collected volume measured at surface [28].

The CTD best practices were strictly followed, such as circulating sweep fluid for every 10m drilled and a wiper trip to the exit window performed for every 20m drilled. Moreover, downhole logging tool<sup>3</sup> was utilized to monitor the drilling parameters such as torque and drag, annular pressure and ECD for the aid of evaluation hole cleaning efficiency [28].

The dynamic over balance during drilling operation (the difference between ECD and reservoir pressure) ranged from 60 – 70 bars and the fact that CTD was operated with slide mode increased the concern of differential sticking. However, this was mitigated by lowering the pump pressure and by stopping pumping and maintaining surface back pressure to provide the pressure needed to keep the borehole stable [28].

#### 4.1.4 Operation Execution

A caliper run was done using Multi Finger Imaging Tool (MIT) to verify free access and confirm good tubing condition prior to setting the Whipstok and start the exit window's milling operation.

However, due to the minimum restriction existing in the surface completion of 3.5 in, the 2 3/8 in BHA was the only option available for drilling 3 in hole section. The Electrical operated BHA

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<sup>3</sup> Reference is made in Appendix A

selected permitted in high flexibility to optimize the BHA as needed for the specific run. This because it is builds in modules [28].

The drag forces acting on the CT were continuously calculated using surface sensor and short interval wiper trip were dictated by tight spots along the wellbore. The figure 4-1 below shows the graph of the drag and tension forces acting on the tubing [28].

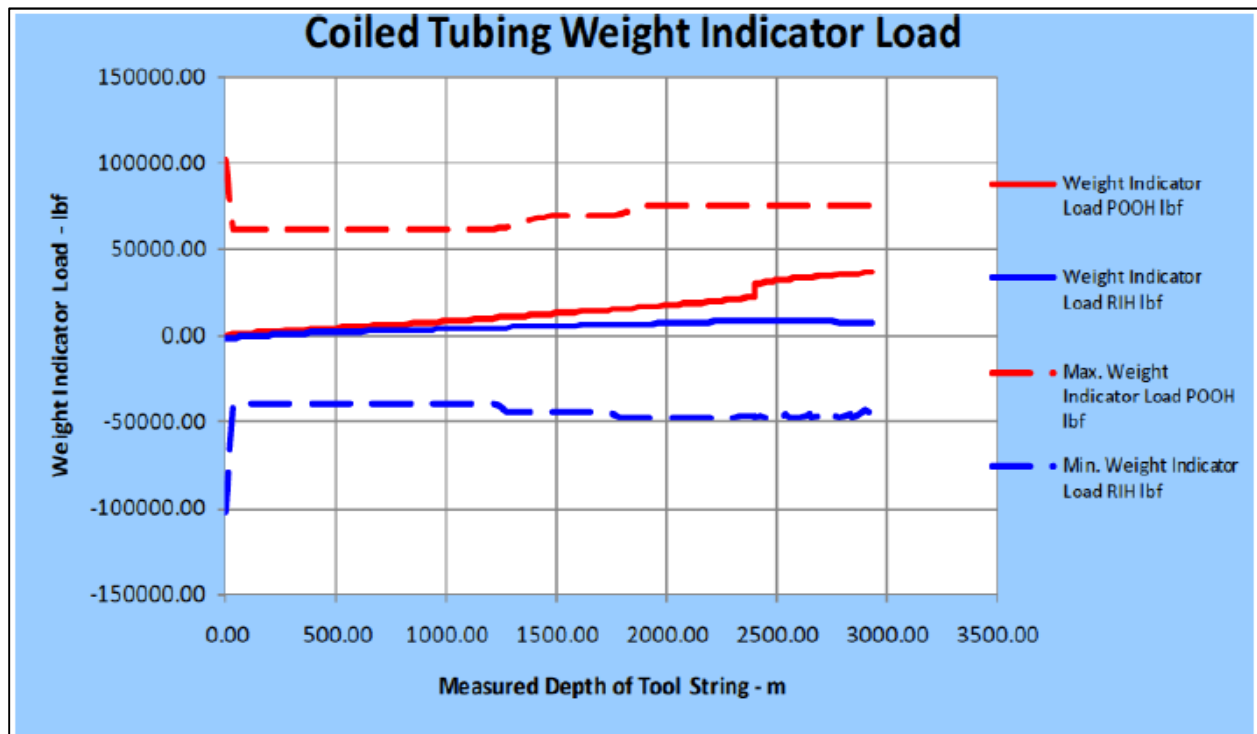


Figure 4-1: CT Weight Indicator load [28].

The real time data acquisition allowed instantaneous monitoring of drilling parameters and proper actions were taken to minimize risks and achieve successful drilling operation [28].

As illustrated in figure 4-2, the accumulation of drilling cuttings is assessed through monitoring the ECD and a hole cleaning wiper trip is performed when increasing trend is confirmed.

The ROP is optimized by using the WOB data so that the whole drilling operation performance is optimized [28].

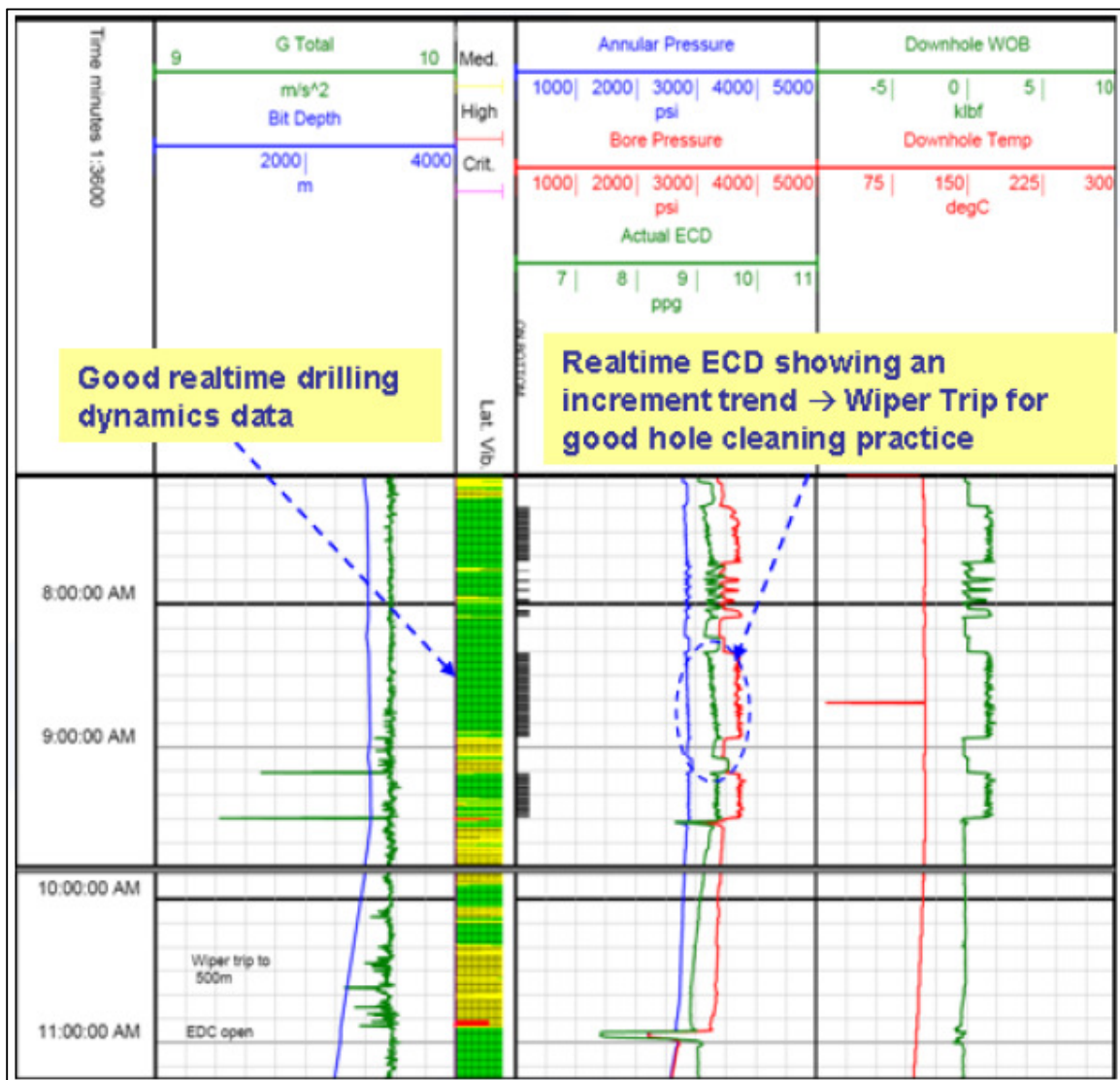


Figure 4-2: MWD Logs [28].

The resistivity data output have showed clearly the penetration through the fault in one of the well drilled in this CTD campaign. However, pressure anomalies were not noticed despite the spike in formation resistivity response [28].

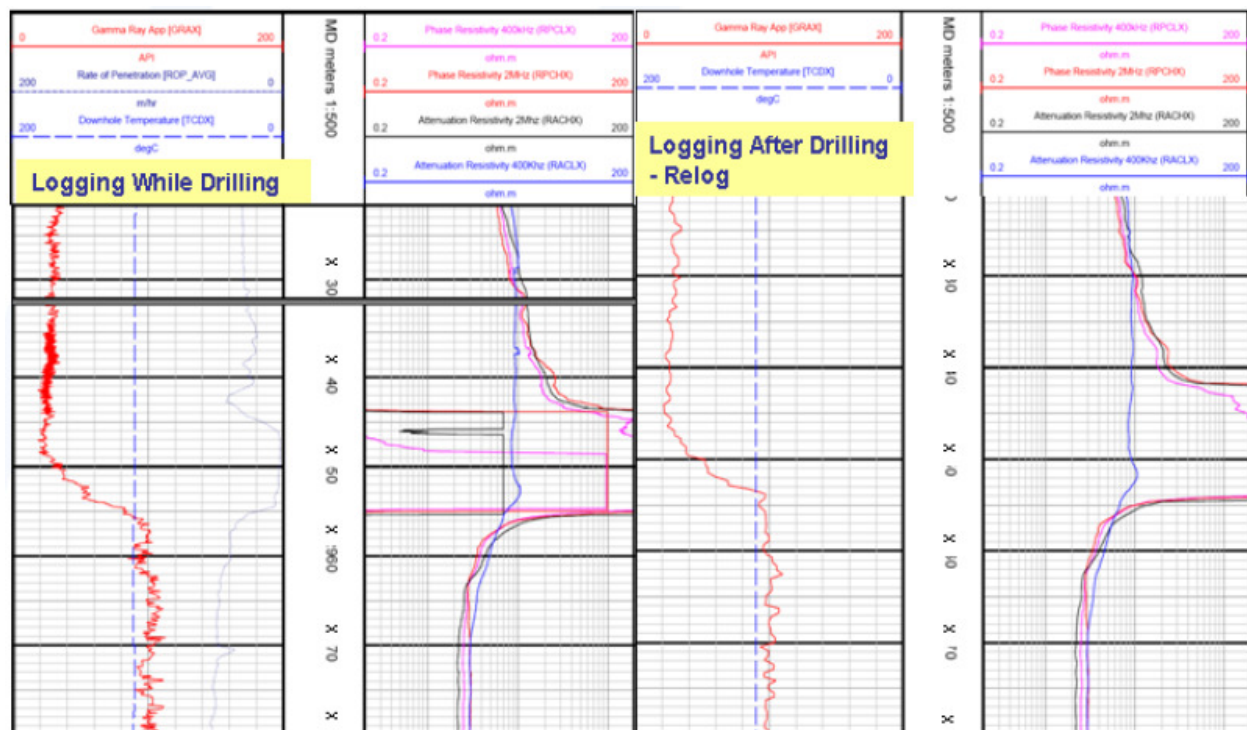


Figure 4-3: MWD Resistivity Log [28].

## 4.2 Cleveland formation – USA

### 4.2.1 Introduction

BP America identified the use of CTD application to drill re-entry wells in tight shale Cleveland formation located in North Texas Panhandle and Western Oklahoma. Initially, this field was developed with drilling vertical wells but due to reducing the surface area where the new wells can be drilled. This was replaced by drilling only horizontal wells conducted since 1997 [29].

In general, BP has performed CTD operations in this area and proved cost saving results in other places around the globe. Therefore, this technique was again considered for drilling re-entry well in Cleveland formation [29].

Intensive studies were carried out to gain better understanding of the formations characteristics in which the well trajectories are passing through. The samples from “MFS3” shale and “MFS4” sandstone were subjected to several core studies in order to identify mechanical failures that CTD wells may encounter. However, the recommendations of these studies that had impact on the operational phase which had to be taken in consideration during detailed planning phase. These are list as in following [29]:

- Minimize build up angle at the lowest when drilling through the “MDF” shale or avoid drilling through as an alternative option.
- Heavy mud weight will increase the shale formation stability but this may lead to fracture the shale and introduce more problems due to limited CTD capacity (not able to rotate and increases the risks of differential sticking)
- Obtain more Full-bore Micro Images (FMI) logs from new drilled wells due to lack of FMI logs. This can give better understanding of acting stresses.
- Time dependent shale instability can be achieved by increasing the mud salinity if chemical failure induced under.

Managed pressure drilling (MPD) condition was selected for drilling these wells using Nitrogen gas to maintain lower ECD and saving the mud cost. Several simulations considering issues such as hole cleaning performance, ROP optimization and acting loads on CT were performed during the planning phase [29].

#### **4.2.2 Wellbore Stability**

Due to limitation s of using large size LCM due to the risk of plugging filters in the BHA, it was hard to mitigate the fluid losses experienced. Using the Nitrogen as drilling fluid made it economically none operable to pump LCM down in the annulus due to large volume of mud needed. However, The CT suffered from excessive fatigue because of high flow rate of 3 bpm and tubing pressure of 3500 – 4000 psi used when drilling the build-up section. For the later wells, this was mitigated by changing the planned drilling program such that CTD was used to

drill the lateral sections that range from 1500 – 2000 ft in the Cleveland sand while milling window and the buildup section were drilled with a work over rig [29].

#### **4.2.3 Hole Cleaning**

After changing the operation scope to drill only the lateral section with CTD, monitoring the return of drilling cuttings closely helped to continue drilling before performing cleaning wiper trip interval from 150 – 400 ft (deviating from CTD best practice which recommends performing a cleaning wiper trip after a short interval ranging between 20 – 50 m is drilled). However, two wells were side tracked due to drilling through shale formations which encountered hole stability problems [29].

#### **4.2.4 Operation Execution**

Despite the technical problems encountered as described above, the CTD has achieved drilling of 20 wells successfully with progressive learning and efficiency trend [29].



## 5. CTD Feasibility:

The DG1 feasibility phase is carried out by group of different disciplines to identify wells designs feasibility, assess the associated risks and estimate time, cost and net profit value (NPV). Finally, the report generated will be submitted for management approval.

At the feasibility phase, the project coordinator must take into consideration all the aspects and flag them in groups of positive and negative bullet points. Then these points are to be compared against each other so that it would be possible to make the correct decision prior initiating the next step where concept selection followed by detailed planning phase can take place.

For offshore operations, when CTD is planned to be carried out as standalone operation, the rig modification if needed due to deck space and loading (weight per square area), power consumption, conflicts with other operation onboard as wells as the limitations of people onboard (POB) capacity must be taken in consideration beside assessing the technical feasibility.

For the technical evaluation, data such as the following need to be available as a basement to initiate feasibility phase such as [23]:

- Candidate wells.
- Well history and tubing conditions.
- Well completions.
- Well barrier status.
- Planned KOP and Target.
- Pore and fracture pressure.
- Maximum circulation pressure available at surface.
- Planned hole size.

Generally, well screening takes into account factors that have impacts on meeting the objectives of CTD during drilling operation and later in well life time. These should be analyzed when DG-1 feasibility phase is carried out. These factors include but are not limited to as in the following [23]:

- Well integrity related issue regarding current conditions of tubing, production packer, and cement as well as an evaluation of their status for the expected life time of the well.
- Overview of minimum ID restriction in tubing and checking optional milling possibility to provide passage for drilling assembly.
- Current completions status and conditions.
- Detailed study of targeted reservoir to optimize side track length and DLS [23]. When well path is defined, it is important to check drilling parameter such as WOB limitation due to helical buckling, maximum available tension on CT, CT fatigue life and hole cleaning efficiency which is related to maximum possible pump pressure [5].
- Project risk assessment.
- Logging and measurement while drilling (LWD) and (MWD) data availability (tools size limitations).
- Project time and cost estimation.
- Rig modification regarding possibility of building extra deck for CT operation and building mud pit as needed.

Although, CTD can be technically feasible but operators may conclude the drilling project does not meet the economical expectation [5]. Therefore, feasibility studies to address the project risk and challenges with expected outcome are vital for successful project management.

### **TTDC specific risk**

As specified above, CTD limitation induce an additional health, safety and environment (HSE) risks compared to conventional drilling operation. These risks highlighted in the following are valid for general through tubing drilling and completion (TTDC) operation in which CTD is part of [5].

- The majority of operational time is spent in reservoir section. Extra well control awareness is needed.
- Possible damages to completion, DHSV, and/or x-mas tree and therefore, all barrier elements must be tested upon completion of TTDC operation.

- Higher ECD induced by high friction due to smaller annulus (Slim hole).
- High risk of surge and swab during tripping for whole wellbore. Down hole pressure gauge (DHPG) is essential to monitor surge and swab as well as down hole ECD.
- Challenges related to kick detection due to small volume of open hole annulus.
- Barrier elements between exit window and B-annulus should be evaluated in advance.

## 5.1 Technical Feasibility

There has been noticeable progress in developing CT services and extending their application but limitations still exist specially for drilling operations. This is due to small sized equipment used in CT in comparison with equipment used in conventional drilling. However these are more tools limitation rather than limitation directly linked to CT functionality [24].

Just like conventional drilling, drilling parameters are inter-connected and affecting each other's. Therefore, oil companies must define optimized drilling parameters such as rate of penetration, hole cleaning efficiency and tripping time [24].

These parameters are dependent on hydraulic performance and mechanical forces available at the drilling bit. In addition, the last two parameters (hydraulic performance and mechanical forces) are dependent on the size of CT selected for the drilling operation as well as primarily condition of the wellbore (tubing and open hole size, well friction.. *etc.*) [24].

The flowchart below illustrates the dependency of selections and alternatives options when objectives cannot be met as the final goal is to rout the drilling project to be technically feasible.

The focus of technical feasibility will be on the following:

- 1- Well Screening and Modeling
- 2- Hydraulic Design
  - Hole Cleaning
  - Mud design
- 3- Underbalanced & Managed Pressure drilling
- 4- Well Control in Slimholes
- 5- CTD Bottom Hole Assembly

- 6- CTD Surface Equipment
- 7- Tubing Selection

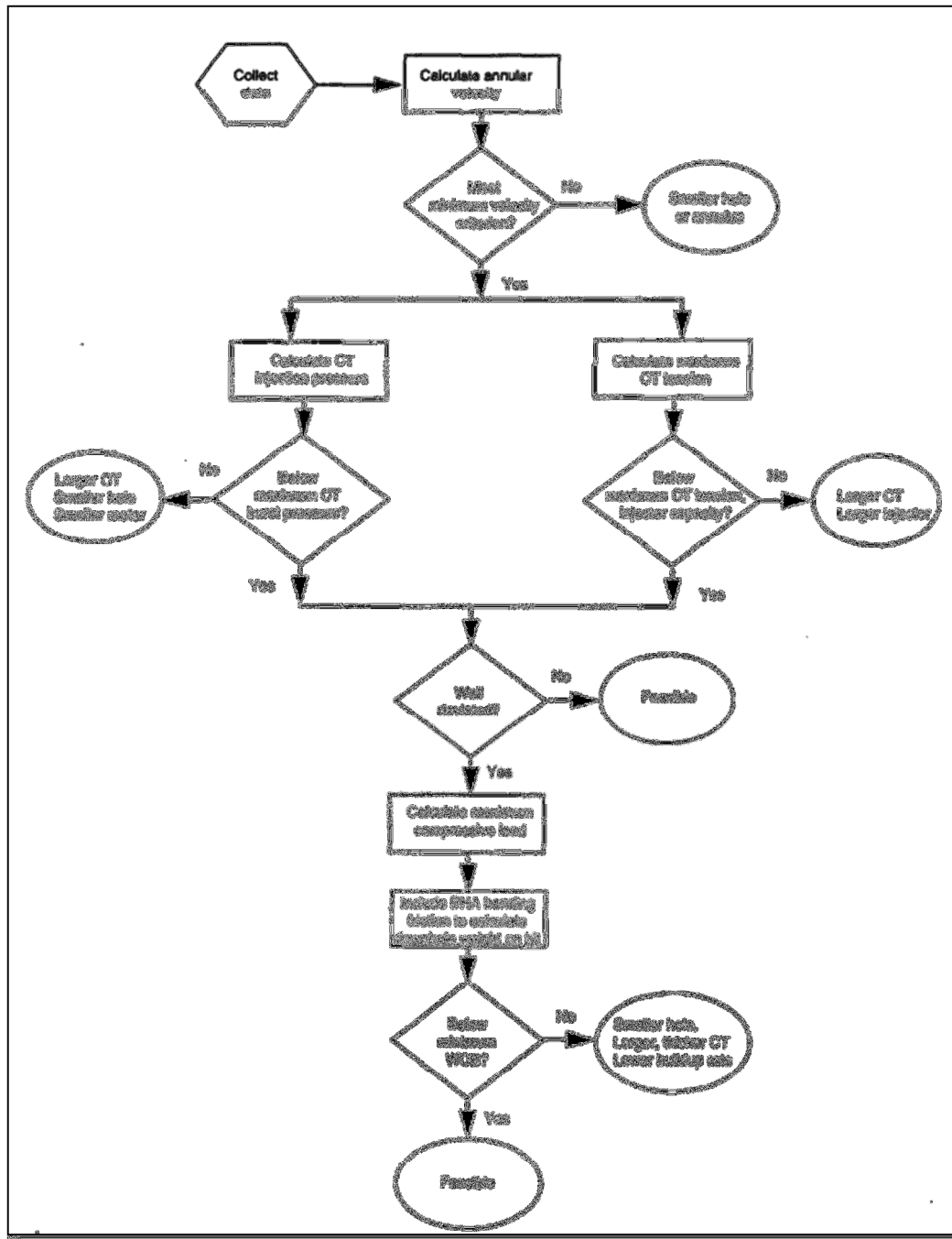


Figure 5-1: Flow chart to achieve a technically feasibility CTD project [24].

### 5.1.1 Well Screening

The feasibility of CTD project planned on GF-A which thesis is related to, kicked off with five candidate wells ranked as “Considered for further investigations” [25] in which expected range of KOP depth and TD were identified as referred to in the table below:

**Table 5-1: CTD Candidate wells information [25].**

WELL	Kick-off Interval		Exit through	Comments
	From	To		
A-11	1 908	2 100	4 1/2" and 7" liner	Mill through two casings. Evaluate to log cement between 4 1/2" and 7"
A-14	2 270	2 274	7" liner	Exit through: 7" liner with hinged whip stock 4 1/2" mule shoe
A-23	2 765	2 806	7" liner	Exit through: 7" liner with gravel pack on the outside, hinged whip stock 4 1/2" mule shoe (3,68" min ID)
A-26	2 035	2 039	7" Liner	Exit through: 7" liner with hinged whip stock Cement quality?
A-31	2 700	2 704	7" Liner	Exit through: 7" liner with hinged whip stock 4 1/2" mule shoe (3,68" min ID)

The intention is to start with an easy well with less technical challenges to build experience and competences for more complicated wellbores [25].

### 5.1.2 Kick off point (KOP)

All KOP are positioned below the Shetland shale to avoid any possible high-pressure zones in Top Shetland. Wherever possible, KOPs are placed so that exit through only one casing string is needed. This is to avoid problems that might be encountered such as difficulties during milling operation and to avoid getting mechanical stuck between the casing and tubing. The quality of cement still needs to be evaluated by logs or by length to ensure safe operation during milling the

exit window [25]. An over view over candidates wells and their schematics can be found in Appendix B.

### 5.1.3 Well Path Modelling

#### 5.1.3.1 A-11 A summary of modelling results

This well is planned with 1152 m side tracked length to reach the target reservoir. It considered a long section for CTD with high risk of failure due to drag constraints as well as drilling uphill (inclination of 95°) for more than 600 m with high DLS of 15°/30 m. High considerations must be taken regarding CT buckling and limited WOB [25].



Figure 5-2: Section view of well A-11 [25].

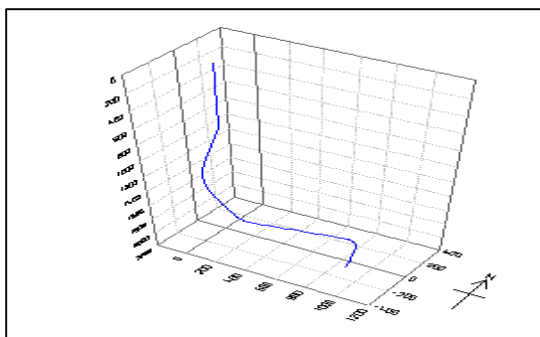


Figure 5-3: 3D view of well A-11 [25].

5.1.3.2 A-14 A Summary of modelling results

The main concern of this well is the high turn (120°) in well path and planned DLS is 19 °/30m. The planned length of this side track is 397 m which is considered a reasonable length for a CTD application. However the drag simulations must be performed to assess feasibility due to high DLS [25].

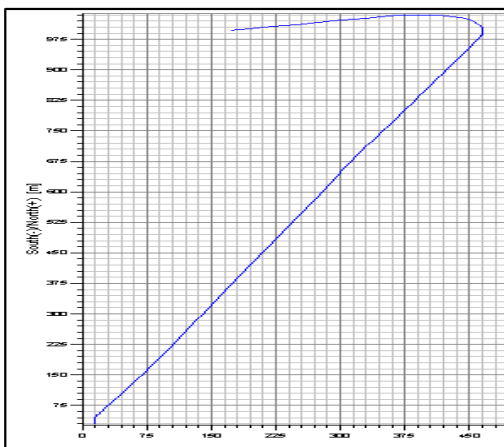


Figure 5-4: Section view of well A-14 [25].

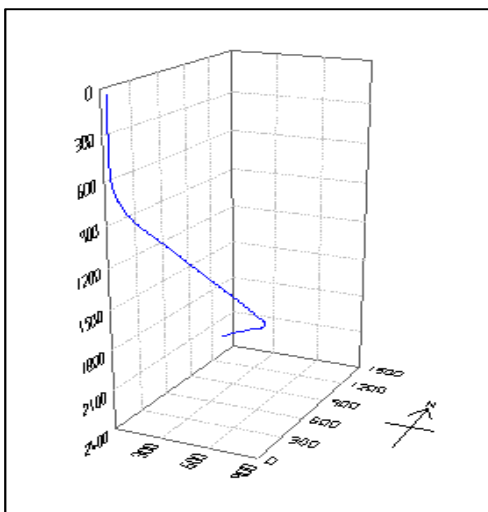


Figure 5-5: 3D view of well A-14 [25].

### 5.1.3.3 A-23 A summary of modelling results

The planned section length for well A-23 is 554m. If this well is planned at the end of the CTD campaign this should be an achievable length. Planned DLS, 6°/30 m, is acceptable [25].

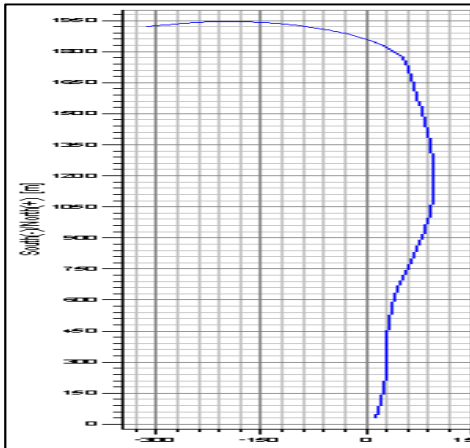


Figure 5-6: Section view of well A-23 [25].

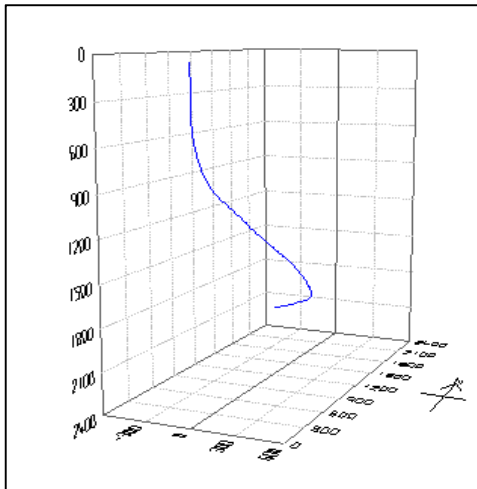


Figure 5-7: 3D view of well A-23 [25].



5.1.3.4 A-26 A summary of modelling results

This is the easiest planned side track in terms of length, DLS, and deviation. The planned section length is 254 m with DLS is 3°/30m and deviation of 86°. Therefore, this should be the first well in CTD campaign [25].

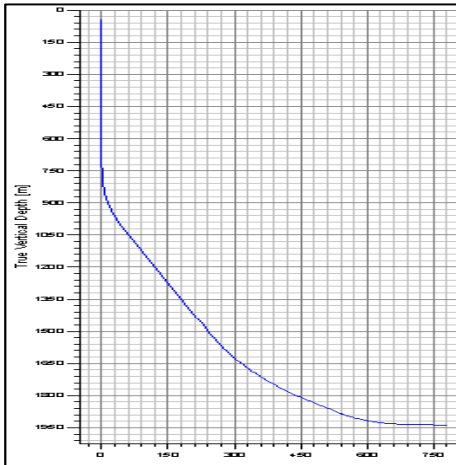


Figure 5-8: Section view of well A-26 [25].

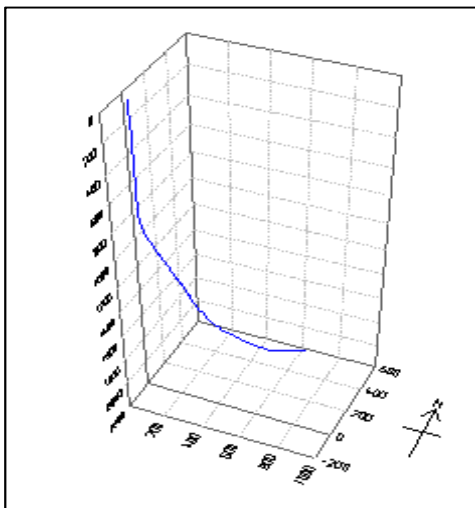


Figure 5-9: 3D view of well A-26 [25].

5.1.3.5 A-31 A summary of modelling results

355 m length side track is planned for this well. This is an achievable length by CTD. However drag simulations must be performed due to high DLS, 20°/30m and turning of up to 57°. Following the planned well path can be a challenge [25].

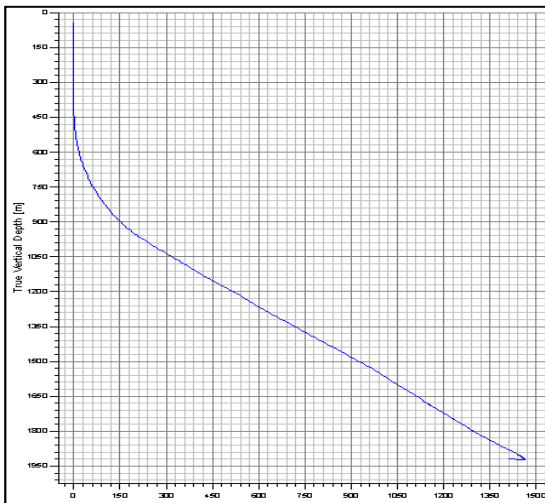


Figure 5-10: Section view of well A-31 [25].

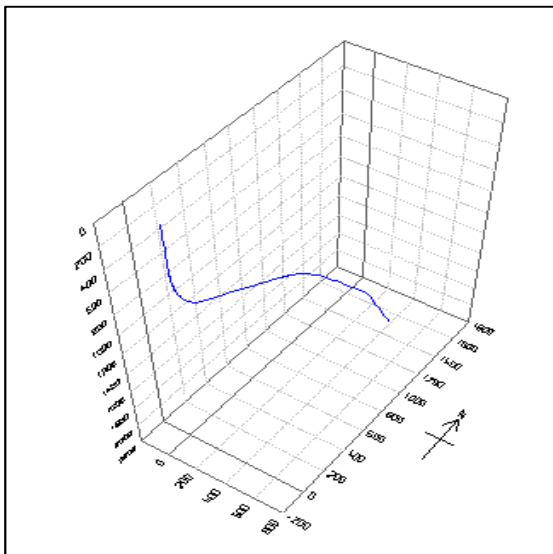


Figure 5-11: 3D view of well A-31 [25].

### 5.1.4 Hydraulic Design

A CTD design requires the optimization of different factors to meet its objectives. The hydraulic design needed to optimize the dependent factors as they are listed below [5]:

- BHP with specified margin.
- Efficient hole cleaning
- CT can withstand maximum expected circulation pressure.
- Minimum flow rate needed to start up down hole motor.
- And, minimizing drilling fluid needed.

The design must take in consideration many variables such as CT ID and length, fluids density and rheology, annular size and velocity, fluid temperature and chock pressure when applicable [5]. An iterative calculation is done using the Wellbore simulator that is built with different numerical models such as solid transport model, mass conservation model, multiphase flow and particle transport in deviated well as well as other sub models are included in the simulator to predict the hydraulic variables such as fluid pressure, density and solid transportation [27].

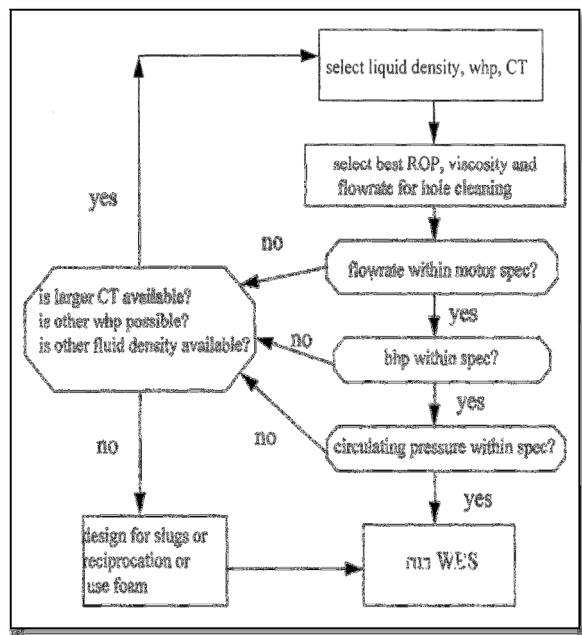


Figure 5-12: CTD drilling liquid design flowchart [27].

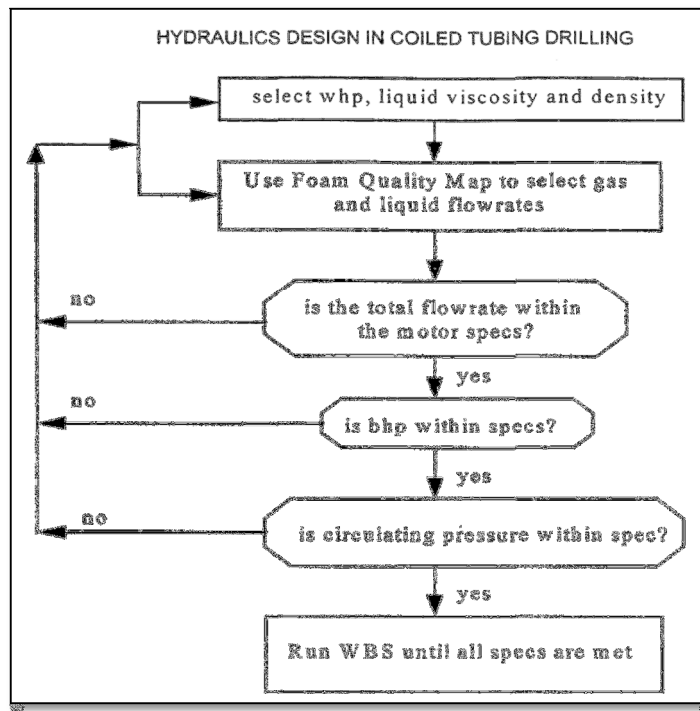


Figure 5-13: CTD drilling foam design flowchart [27].

#### 5.1.4.1 Hole Cleaning

Wellbore cleaning is directly related to annular fluid velocity in which can be calculated when the hole and tubing size are given. Based on the hole size, the largest available downhole motor can then be selected, and CT dimension dictates 80% of maximum fluid rate going through the motor which will result in the annular velocity that can be achieved [24].

Normally, the horizontal or high deviated section and where well ID is relatively large enough to slow down the annular velocity are considered to be the most critical section along the wellbore regarding hole cleaning efficiency [24].

A simulation program is run to predict minimum annular velocity needed for given wellbore size with different deviation angle range from vertical to horizontal sections. When maximum annular velocity can be achieved is not sufficient enough for hole cleaning, a larger CT must be then selected to make it possible to increase the flow rate through the coil and also reducing the annular

cross section area. If bigger CT is not available operator must consider reducing the hole size to improve the annular velocity so that hole cleaning efficiency is maintained [24].

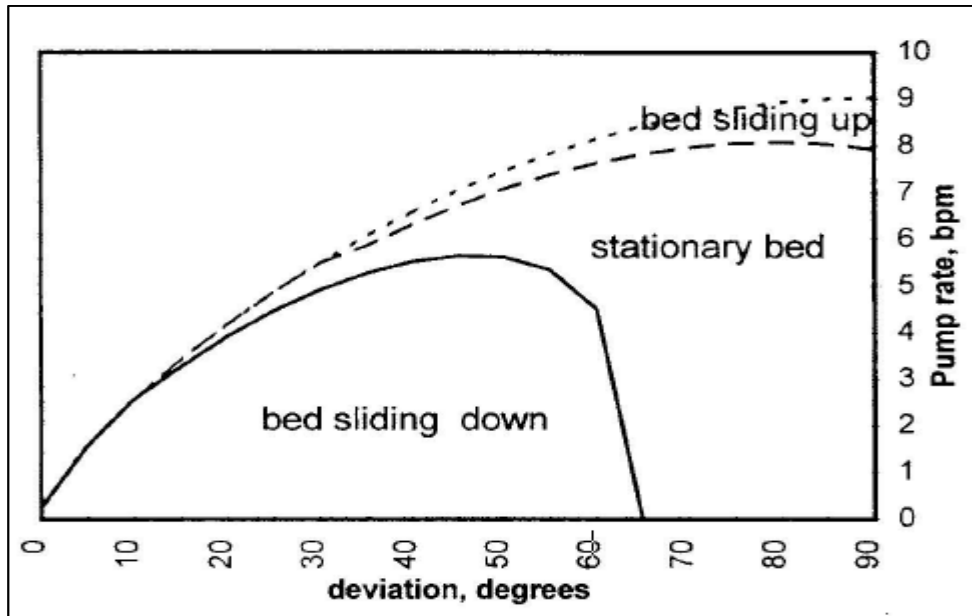


Figure 5-14: Simulated graph for water in the casing flow regime [24].

#### 5.1.4.2 Mud design

The basic requirements for drilling fluid's rheology used in conventional drilling are different when operating with CTD. However, these requirements are similar to the ones valid to slimhole drilling due to small pipe ID and annular size. Therefore; drilling fluid must be designed to minimize pressure losses induced due to friction as well as minimizing the ECD [5].

As previously mentioned, pipe rotation is not possible with CTD operation which then exclude the option of mechanically removing the cutting bed settled along the wellbore. Therefore, increasing the flow rate will be needed as prevention and/or mitigation measure to overcome this issue. In some cases, it has been noticed that thick fluid with low flow rate has the ability to maintain clean hole by transporting the solids produced the drilling operation by means of suspension. However,

in CTD this can lead to major consequences due to the fact CTD is operating only with sliding mode and once cutting bed is generated, it will be difficult to remove even with high flow rate [5]. Experiences have showed that using low viscosity fluid can maintain better hole cleaning because it will stay in turbulent flow even with low rates and preventing solids accumulation in the wellbore leading to better hole cleaning efficiency. Usually, high viscosity fluid is circulated occasionally (for example every 5 m drilled) to sweep the cuttings and debris and maintain the hole clean.

The drilling mud's criteria that are valid for slim hole drilling are valid as well for CTD operations as listed below [5]:

- Optimized viscosity
- Density stability
- Shale inhibitor
- Compatible with reservoir formation
- Good lubrication properties
- Capable of efficient drilling cuttings transportation.
- Stable at operating temperature.
- Fluid-loss within acceptable criteria

When drilling in mature field with overbalanced drilling technique, depleted and high pressure formations can be present along the well path. The mud weight used must be heavy enough to compromise for high pressure formations. However this will lead to high differential pressure in low pressure and depleted zones which increase the risk of differential sticking [5].

Historically, drilling at overbalancing has low successful record due to differential sticking with no possible pipe rotation and hole collapse sequences when attempts are done to free the pipe [30].

The CT set up provide ideal solutions to use underbalanced or managed pressure drilling as described in the following sections [5].

### 5.1.5 Underbalanced and managed pressure CTD

The majority of CTD performed in Canada is primarily to avoid sensitive reservoir damages by maintaining underbalanced condition while drilling with CT. The main advantage of CTD is represented in the ability to produce the fluids from the formation and simultaneously pumping and tripping in and out of the well [6].

Risks of fluid influx from high pressure zone to the wellbore must be analyzed and maximum possible pressure that can be seen at surface must be lower than surface pressure control equipment's operating limits [30].

CTD is distinguished by the ability of drilling multilaterals in live wells. However, drilling with underbalance application is "reservoir specific" which means depends on the reservoir properties and characteristics [4]

In managed pressure drilling, the mud weight is used to provide the primary barrier while surface pressure is applied providing the possibility for dynamic overbalance to control borehole stability by using surface pressure to control variation in well pressure due to ECD effects [31].

### 5.1.6 Well Control in Slimhole

As mentioned earlier, the presence of high pressure and depleted zones along the well path for candidate wells may require higher mud weight than what actually is required for well control purpose. Therefore mud weight is generally optimized to compromise the following factors [5]:

- Well control
- Differential sticking
- Hole stability
- Minimizing ECD effect
- Minimizing formation damages

When drilling slimhole and a well control situation occur (uncontrolled flow of hydrocarbon), this should be handled with driller's method due to small annular volume comparing to CT string

volume. For example, at 10,000 ft of 2<sup>3/8</sup>-in CT, the internal volume of CT string is 6.6775 m<sup>3</sup> whilst 0.8 m<sup>3</sup> represent a volume of 500ft of 3<sup>1/4</sup>-in openhole section [5].

As a results of this big difference, no advantages are given by using the wait and weight method. However, the small annular volume will result in turbulent flow even with low circulation rate. The turbulence will work to break and disperse the gas in the liquid and eventually less kill pressure is required at surface [5].

The small annular volume will also assist in an early detection of penetrating the high pressure zone because the bottom up circulation arrive surface quicker than conventional wells which then limit the risk of the kick [5].

Consequently, small volume of gas influx to the wellbore has a considerable impact on well pressure due to small well volume which will lead to longer gas column in the annulus. Therefore, the measures must be in place to help in early detection of influx once occurring [5].

Detailed drilling program must take in consideration well control action as per the company guidelines. These actions must be available for the drilling crew and must be practiced during the well control drills conducted over a defined periods [5].

The practice of taking slow circulation rate (SCR) (to take in account ECD during the well kill) is normally done after [5]:

- When changing the BHA
- Changing the mud weight
- Every 150m of drilling
- Repairing the mud pump
- New driller's working trip.

### **5.1.7 CTD Bottom Hole Assembly (BHA)**

The drilling BHAs that are used for CTD are the same equipment used for conventional rotary drilling but designed with smaller diameter. The tools that are commonly used with normal CT



operation such as the connector, flapper valve, disconnect and circulation sub and of course the coil itself are also utilized for the CTD operations [5]:

An exclusive orientation sub is added to the BHA to steer the well to the required direction. The drilling equipment and techniques will be the same as used in slid drilling mode used with conventional drilling [5].

The CTD BHAs are available with mud pulsed telemetry, and the other type is electrically powered tool using an installed electrical line (e-line) in combination with CT [7].

#### 5.1.7.1 Orienter

As indicated by its name, this tool compensates for the CT rotation disabilities. It is utilized to turn the drilling BHA and together with the bent sub drives the drilling bit to meet the desired direction. It is operated based on differential pressure inside and outside the CT. The pressure pulses sent from surface mud pump down to the tool through the coil will drive a piston and making a turn in steps of  $20^\circ$  increment clockwise or counter clock wise based on different manufacturer design. This sequence requires pulling off bottom to start actuating the orientation sub [32]. The sub can turn only in one direction in which requires approximately  $300^\circ$  when correction needed to meet the desired well trajectory. However, confirmation of correct tool face is difficult to assume before the drilling is resumed and the torque is determined [5]. Lifting of bottom can also induce fatigue and may reduce the operation life time of the CT [32]. The simplicity, as well as the operational reliability is the advantage of this orientor type [5].

The electrical orientor is also available for electrical system and gives the possibility to turn the bit without the need to lift of bottom. They can be operated in high torque and are independent of flow rate with advantage of giving smooth well trajectory due to better controlling mechanism. However, the electrical system can impose logistic constrains for the project due to the weight of the CT with installed e-line [33].

### 5.1.7.2 Downhole Motor

The performance of CTD BHA is dependent on the motor selection. The selection is dependent on the BHA type. When rotary steerable system (RSS) is used a Positive Displacement Motor shall be so that the RSS can be powered up.

However, the motor must be able to operate optimally under low flow rates and can give the necessary torque needed to the bit. For CTD the motor should meet the following criteria [5]:

- Long operating and circulation time reliability to ensure drilling success.
- Capable to achieve high doglegs ( $30^\circ$  -  $40^\circ$  / 30m) consistently.
- Providing sufficient torque at the desired flow rate.
- Maximum operating differential pressure to be less than ~50 bar.
- To be short in length to minimize the distance between directional and inclination subs and the bit.
- Provide bit revolution range from 200-400 rev/min.
- Operating temperature within expected bottom hole temperature (BHT).
- The motor must be elastomers resistant to avoid wearing the elastomer component in the motor.

The two main types of down hole motor are the positive displacement and turbine motors available for slim hole drilling.

- Positive displacement motors (PDM):

It provides the mechanical power needed to drive the drill bit is generated from the hydraulic power created by pumping the drilling mud. This motor consists of the stator and the rotor [34].

The power section is comprised of two components, the stator and the rotor. The stator represents the steel housing with inner bore designed with helical pattern in the center. The helical steel shaft is the rotor in which together with the stator create a seal by their helical shape. The rotation of the lobes is initiated by the pressure drop across the cavity that is achieved when the drilling fluid flow through [5].

As illustrated in figure 5-15, the number of lobes the stator has an equal to the number of rotor lobes plus one. In general the more the number of lobe the less rotational speed is given by the PDM.

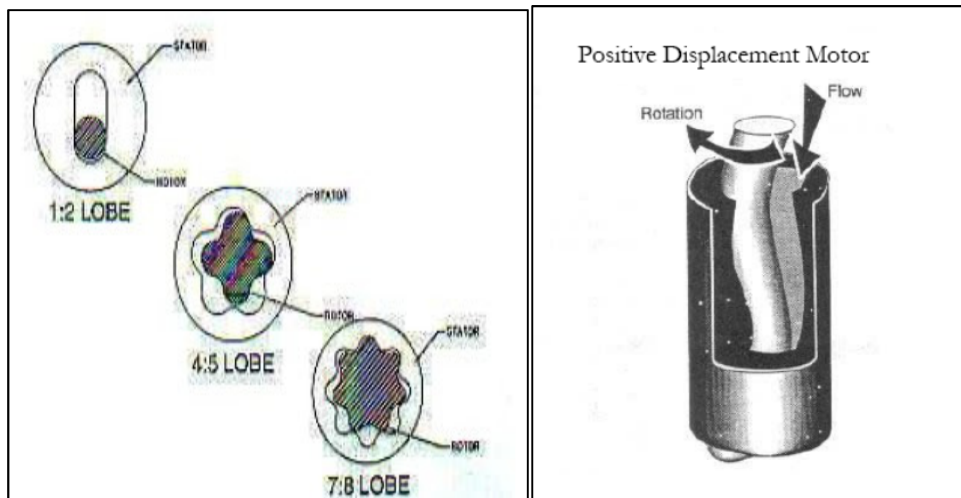


Figure 5-15: Positive displacement motor [34].

Moreover, the torque output is proportional to the differential pressure which is proportional to the total length of the power section. The PDM is built in modules which are classified in stages to allow controlling the torque output needed to meet the job objectives. This means the longer the PDM the more torque is available at the drilling bit [34]. A rubber seal between the rotor and stator is required to operate the motor. The rubber is subject to damages induced by gas and swells under exposure to aromatic fluids at high temperature conditions.

However, the benefit that PDM provided over turbine motors are [5]:

- Operating at low differential pressure.
- Permits the use of PDC bits because of low revolution speed (range 150 - 300 rpm).
- Reliable
- Built in adjustable bent housing.
- Medium to high torque output.

**Turbine motors:**

This motor does not contain rubber components so that is not affected by the type of the mud and BHT. It runs at high speed limiting the options of the drilling bits to high speed diamond bit. However, the Polycrystalline Diamond Compact (PDC) bits can be used by reducing the speed using a gearbox below the motor but this will limit the buildup rate of the motor. This motor is seldom used in conventional CTD due to high surface pressure and high flow rate required which will negatively affect hole cleaning capability due to higher ROP [5].

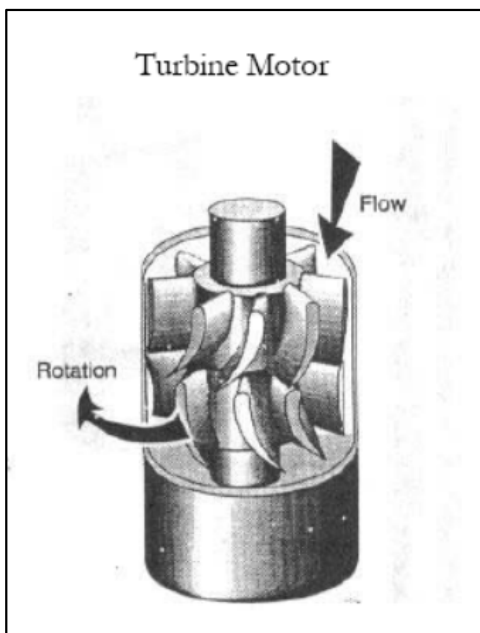


Figure 5-16: Turbine motoe [34].

5.1.7.3 Bit Requirement:

The bit selection in slimhole drilling is generally limited. These constrains are represented in the motor selection which is related to the tubing size and specifications resulting in flow rate and torsional limitations [5]. Experience have showed how small changes in bit design can make significant improvement in drilling operation due small hole size affecting the annular clearance [35].

Primary bit features that need to be taken in consideration during design phase to meet the drilling objective for different drilling phases and are as in the following [5]:

- Torque:

The torque generated while drilling must be minimized in CTD by compromising the ROP due to limited flow rate. For a short while, the aggressive bits can provide high ROP but motor stalling is then very likely to occur. Motor stalling will lead to extra time spent to resume the effective drilling process due to picking of bottom, and stop pump to adjust the tool face [5].

Consequently, interrupted tool face may lead to diverting the drilled section from the planned target especially when drilling with high dog severity. Therefore, its crucial compromising ROP to operate within the torque range for the given weigh on bit (WOB) [5].

- Steerability:

Just after the KOP and in the beginning of the openhole section where the buildup rate is high, it is very important to have a bit designed with great steering flexibility so that directional well trajectory can be achieved. The bit design is crucial for the bit stability and eventually might be important for drilling the tangent section [5].

- Bit Life:

This is the operating life time of the drilling bit while providing reasonable ROP and maintaining gauged hole. However, the ROP can be compromised with respect to maximizing drilling time and keeping the hole in-gauged since longer time could be spent on performing a trip to change the drilling bit [5].

- ROP:

It is always intended to design the bits that ensure higher ROP to reduce the drilling cost and meeting the target depth prior to the need of changing the bit or other possible failures [5].

**Bit selection:**

The selection of primary and optional bit will be done during the detailed planning phase. However, the selection must be made based on formation characteristic in which will directly influence the hole cleaning efficiency and the motor selection so they match for revolution speed, flow and torque [5].

## 5.1.7.4 Logging tools

These are categorized based on data transmission telemetry system between the down hole tool and surface acquisition system: mud pulsed, electrical, fiber optic and electromagnetic. The logging tools are used for directional measurements and to get the formation natural gamma ray signature identifying drilling through new formations [5].

The mud pulsed tools are communicating with surface equipment through the drilling fluids. These are proved to be reliable but limitations with respect to data transmission for underbalanced drilling with gas injected in tubing. For the logistics aspects, these are preferable to use because of excluding the extra weight from the e-line or the fiber optic [5].

## 5.1.7.5 Whipstock

The whipstock is a steel “wedge-shape” [36]. designed with a groove that goes along the body down to the down side. It is set in the casing at the KOP depth and oriented to the desired azimuth. It acts as a basement directing the milling bit to drill the opening window resulting in deflection angle that is dependent on the selected edge-angle of the whipstock and then the drilling of the side track can be performed [36]. However, for CTD it is crucial that the maximum OD of the whipstock can pass through the minimum ID restriction existed in the tubing and it can be expand up to the liner/casing ID at the setting depth. It is also important that the axial line passing through the whipshock is at the center of the wellbore so that no restrictions are encountered when running with milling assembly. A Lead Impression Block (LIB) might be an option to confirm the correct positioning in the wellbore to confirm no mechanical obstruction is created at the top of the whipstock.

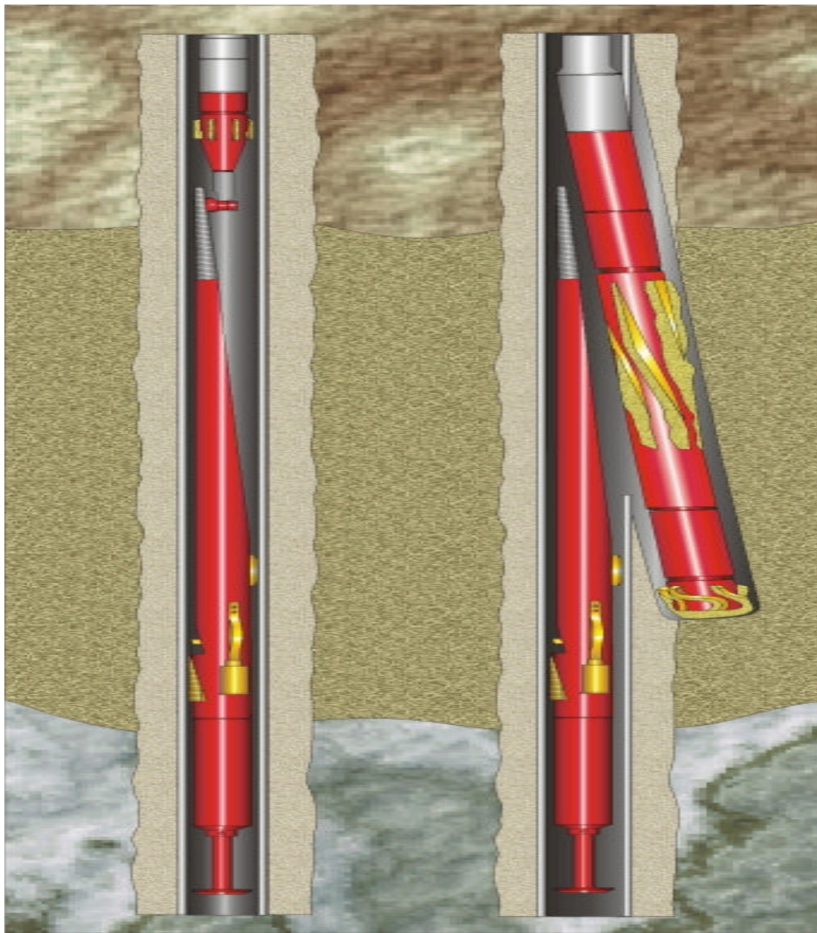


Figure 5-17: Cased Hole Whipstock [37].

A whipstock types with hole inside gives the possibility to produce from the mother well and the new re-entry lateral section is used in multi-laterals wells.

### 5.1.8 CTD Surface Equipment

The surface equipment to handle the drilling fluid will be the same as for conventional drilling. However, when planning CTD as standalone operation simultaneously with conventional drilling, a modification on the rig is likely to be done to withstand the load per square meter for the new installed equipment. However, the drilling fluids equipment needed are as in following [5]:



- Choke manifold
- Active/Trip tank
- Degasser
- Shaker
- Vacuum degasser
- Centrifuge
- Reserve tanks min 60 m<sup>3</sup> total volume
- Fluid Pumps

### 5.1.9 Tubing Selection

#### 5.1.9.1 Tubing Tension

The tension forces acting on the tubing must be calculated taking in consideration all other affecting parameters such as tubing weight, tubing buckling, temperature, buoyancy, and wellbore friction. A simulation is run to predict the drag and maximum surface tension expected. The CT maximum tensile limit will then be compared to the expected tension plus 15000 lb of over pull to determine the tubing size to be used for the operation. The pulling capacity of the injector head must also be confirmed otherwise a new injector head with higher pulling capacity must be used [5].

#### 5.1.9.2 Weight on Bit (WOB)

A simulation program is used that predicts the maximum available WOB that can be applied for the given CT size. This parameter is crucial for drilling in horizontal and highly deviated wells. Therefore, it is important to determine the compression loads that can be applied on the CT to provide the required WOB taking in considerations the buildup section and DLS along the



wellbore. Similarly, the tensile load, the maximum needed compression load must be compared with the CT designed compressional load to confirm the suitability of the CT for the operation [5].

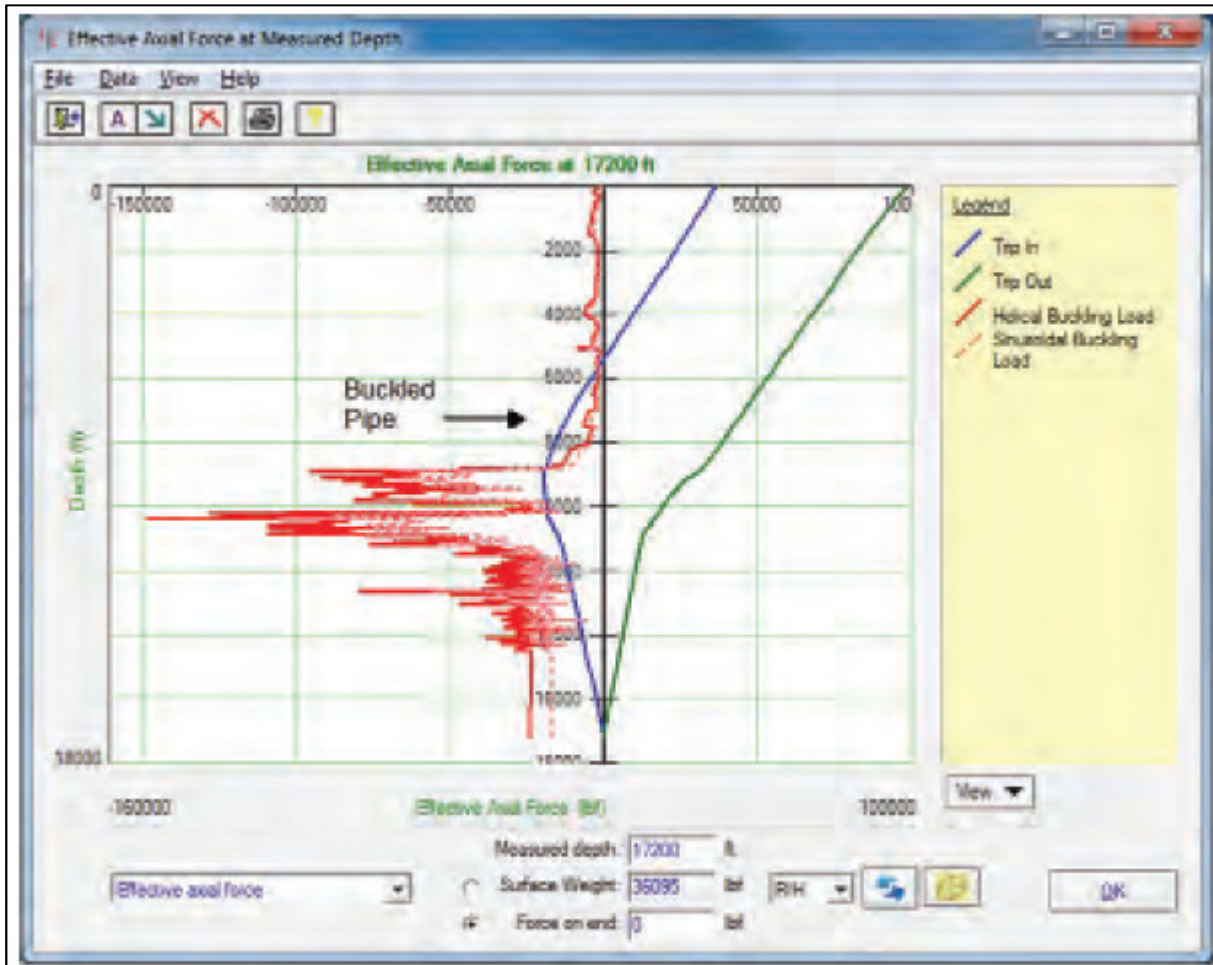


Figure 5-18: CT weight load simulation indicating buckled pipe [38].



5.1.10.2 Plug and abandonment (P&A)

The plan of final P&A must be taken in consideration during well design phase for both, the mother well and the lateral section. This can be planned based on individual well configuration that can vary from one well to another. There is no general solution existed. Therefore, the final P&A can be done above the lateral (covering several branches). In this case, there will be no issues related to the final P&A in the design phase for through tubing drilled and completed (TTDC) wells [23].

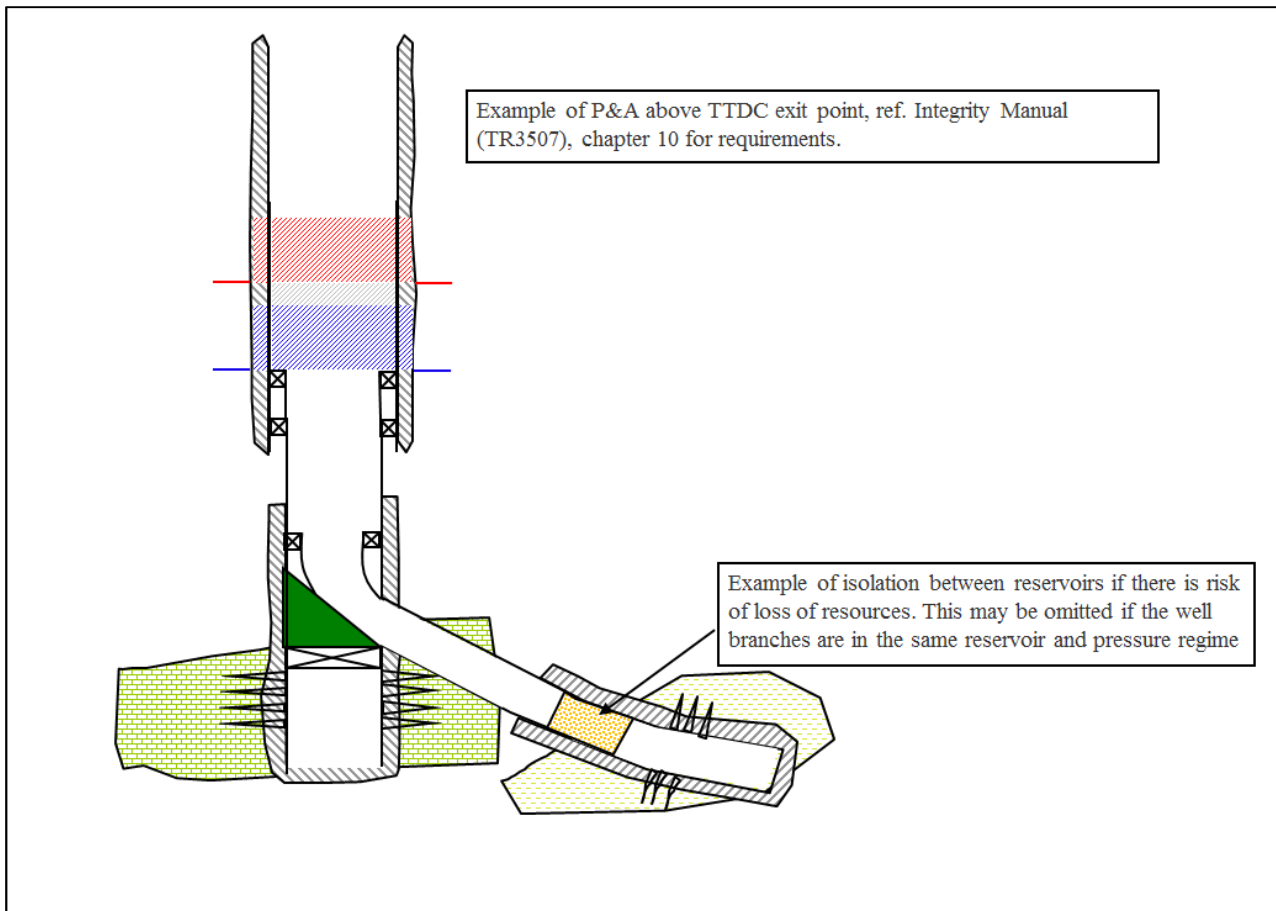


Figure 5-20: Example of P&A of TTDC wells [23].

## 5.2 Platform and utilities

### 5.2.1 Personnel on Board (POB)

The capacity for offshore rigs is known to be limited. The CTD operation is planned to be performed simultaneously without compromising conventional drilling operation on the platform. Therefore, there will be extra need for bed space with a number of bed that is three times larger than in a normal intervention operation, assuming that a separate CT mud plant is utilized. However, fewer personnel will be needed onboard during rig up and rig down activities. In addition to the CTD personnel during the operation, a modification team has to be sent out prior to the campaign to prepare the rig in terms of deck space and power supply.

The allocation of extra beds will indeed influence other planned activities on the platform and other alternatives will be looking at daily shuttling or mobilizing a floatel [25].

### 5.2.2 Space on deck

The equipment needed for CTD are more than what are needed for ordinary CT operation and therefore more space on deck will be needed. Extra deck that can withstand the heavy weight of heavy equipment like mud plant will be needed. For safety requirement, if a boat is used to carry the mud plant then the derrick mud plant must be the backup option for CTD and simultaneous operation will be no longer possible [25].

## 5.3 Time and Cost

Similar to other projects, CTD should be optimized to ensure effective cost strategy taking in considerations the technical limits during execution phase. The total cost estimated to run the project is crucial to ensure management approval. It is therefore, the planning engineer responsibility to choose the most competitive solutions that offers the most effective cost saving. However, the cost is inter-connected with project's time estimation which can be predicted by the aid of using actual time spent to perform the specific task when other wells were drilled [25].

The figure below shows the P10, expect time and P90 in days as the time needed for preparatory operations, prepare mother wellbore for P&A, drill side tracked section and running completion.

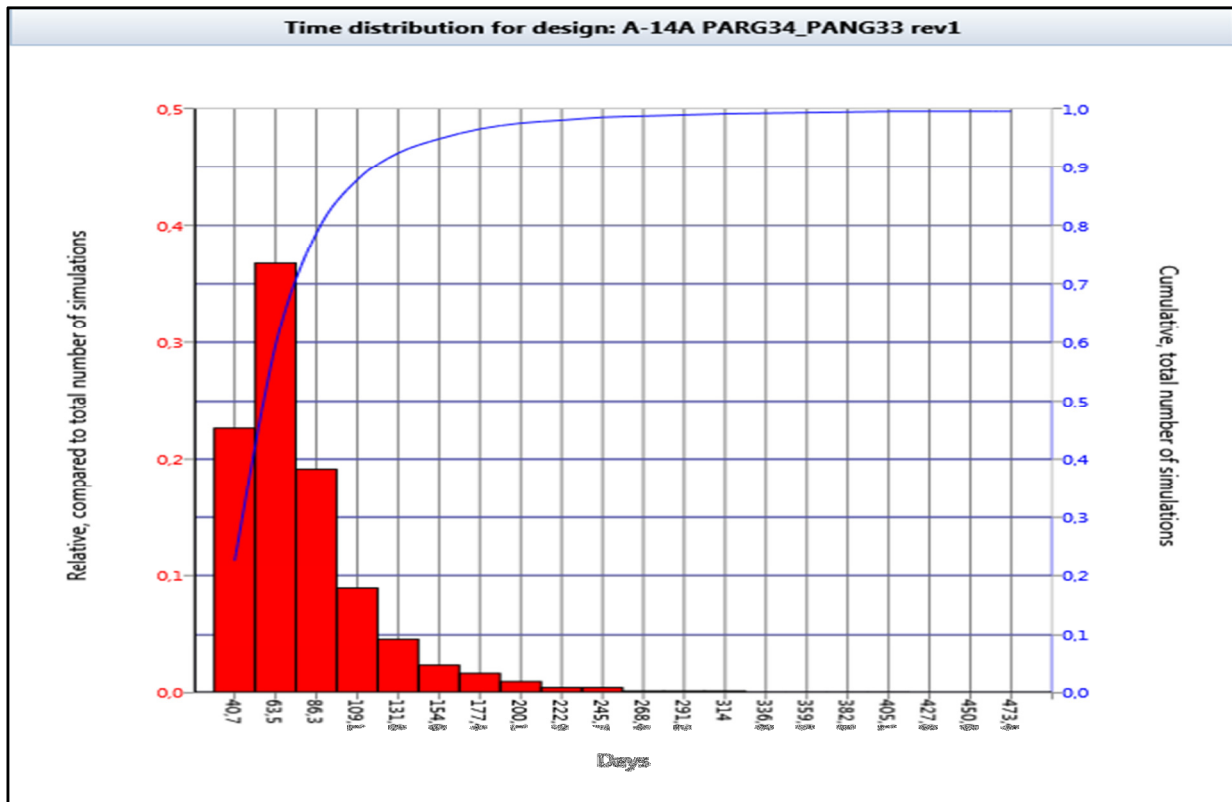
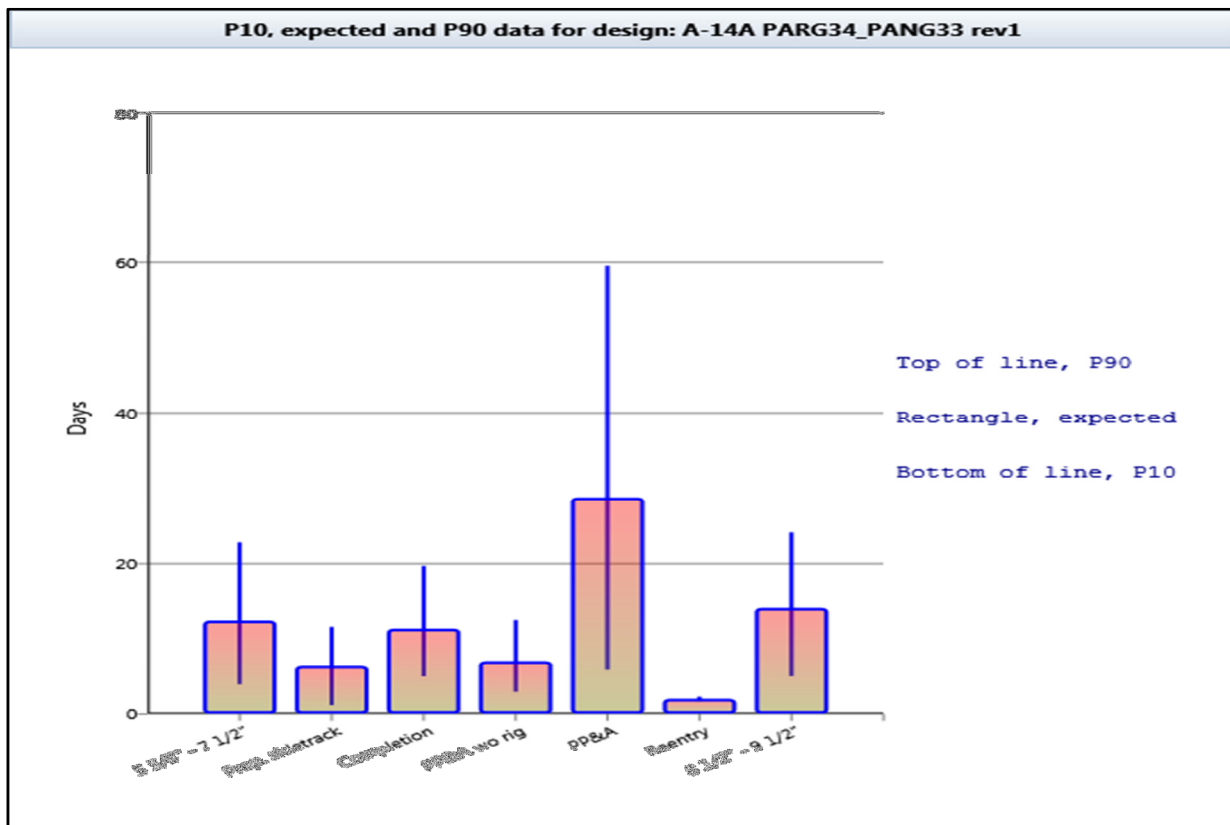


Figure 5-21: Time estimation using drilling & well estimator [25].



**Figure 5-22: Activity time estimation using drilling & well estimator [25]**

The daily personnel rate has a significant contribution to the total cost especially at the start of the CTD campaign. This is due to limited experience and the extra personnel with different competences that must be available to ensure successful project execution. Eventually, this number can be reduced when experience is built up and both the operator and the CT provider need to cooperate to cross train the offshore personnel so that POB can be kept to minimal.

Unlike the drill pipe used for conventional drilling, the CT has limited life depending on many factors such as pressure, number of cycles over the goose neck. In general, the CT itself can contribute up to 10% of the total CTD well cost [24].

The surface equipment and BHA rental costs together are considered the major contributors to the total cost needed for the CTD. This can be as much as 50% of the total cost needed to drill the well [24].

The daily rental cost and services that are run during well intervention, and then for drilling, and completion multiplied by the number of days estimated can give sufficient cost estimated needed for the execution phase.

Moreover, the top side modification such as building new deck, mud plant and other modifications are adding extra cost for the whole project which considered very expensive in overall cost picture when only few wells to be drilled.

At last the project estimated total cost will be compared to value added investment and the final NPV can be estimated and then cash allocation can be approved by the license management.

## 6. New Technologies

Implementing new technologies can make great difference to drilling operation. The new technologies are intended to give better solutions than the existed services in the marked. This section will list few new technologies that can make positive impact to the overall project feasibility.

### 6.1 Rib Steerable Motor (RSM)

In conventional drilling, the Rotary Steerable System (RSS) allows dynamic control of well trajectory with rotating drill pipe and slide mode drilling is no longer required to kick the well to the desired direction [36]. This is simply achieved by three independent hydraulically powered ribs as it shown in fig 6-1. Generally, the RSS enables drilling smoother wellbore with less tortuosity in more complex trajectories because of its ability to actively controlling the steering system [39]. With conventional motor, the tool must be rotated by the orienting sub in order to achieve the desired direction. This tool is capable to steer the drilling bit without a need for rotating the entire BHA and eventually compensates for the CT rotations limitation and exclude the use of the orientation sub [39].

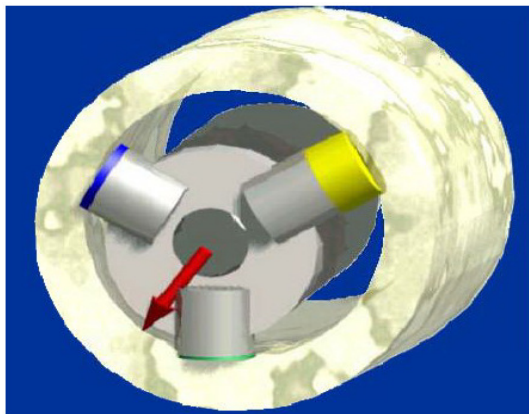


Figure 6-1: Independent adjustable ribs [39].



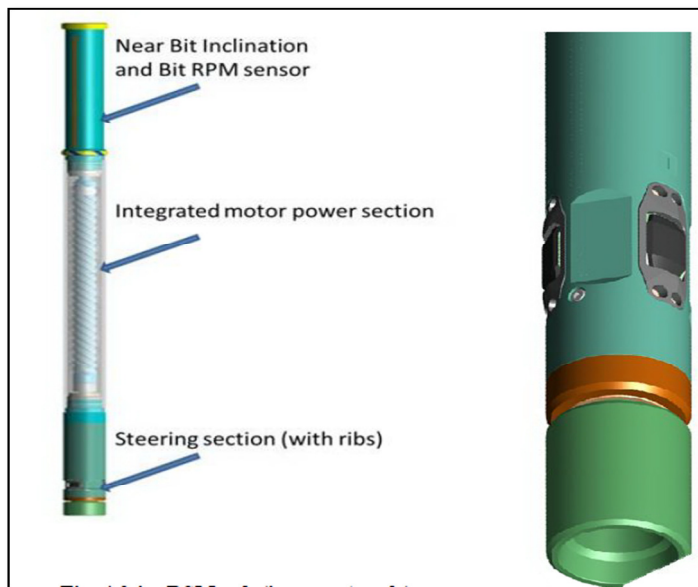


Figure 6-2: RSS motor [39].

As illustrated in figure 6-2, the new 3in Rotary Steerable Motor (RSM) used for CTD operations consists of near bit inclination, bit RPM sensor, integrated motor power section and steering section that is incorporated with the ribs. This tool that is designed for drilling 3 ½-in and 4 ¾-in hole sizes can be also run on e-line. This will allow for instantaneous communication with the tool because of faster telemetry link between surface and downhole equipment [39].

The four operating modes which are available for the ribs can be listed as in the following [39]:

- “Off mode”: All ribs are retracted within the OD of the tool to prevent unintended steering. This is typically used when RIH and when POOH.
- “Inclination Hold Mode”: Automatically controlled ribs in order to keep the current hole inclination.
- “Steer Mode”: The engagement and dis-engagement is controlled internally to achieved the desired azimuth and hole inclination.
- “Center Mode”: Steering is minimized with uniformly engaged ribs.

The drill bit is driven with the incorporated power section mud motor that is operated within a wide range of maximum 120 gpm flow rate and differential pressure up to 1450 psi. This tool is

designed to be fully compatible with all existing CTD downhole monitoring and MWD equipment [39].

The main advantages this tool can offer are:

- The inclination measurement sensor is placed closer to the drill bit which makes it easier to define the hole inclination and proper action is taken when the drilling is heading to unintended direction. This will help to target thin beds that are typically the purpose of promoting CTD application.
- Reducing wellbore tortuosity by actively controlling the tool ribs to maintain the angle needed for drilling the tangent section. In conventional BHA, this is done by routing the well path left and right to get the desired direction in which eventually results in snake shaped wellbore.
- Reducing the drag on the CT and longer laterals can then be drilled with CTD. This is related to the point above, as smooth hole will reduce the friction forces acting on the CT and more WOB will be available at bottom so that it will be possible to drill deeper targets.

## 6.2 HydraSet™ CT Jar

The limitation of small overpull available at surface has a high impact on CTD planning especially when candidate wells are to be drilled in old reservoirs with low pressure and high pressure formation overlap with drilling operation. A high mud weight will then shall be chosen to maintain borehole stability for the high-pressure formations and creating high stuck risk situation. This is due to the high overbalanced condition in the depleted.

Keeping in mind that coil cannot rotate, this will present the hole cleaning as a big challenge and needs to be properly understood by using proper modeling in order to prevent non-productive time associated with performing hole cleaning trips. When reservoir characteristics allow underbalanced drilling, the cutting removal and tubing stuck problems will be no longer an issue. Furthermore, CTD operation in Canada has proved that drilling of 200m can be drilled without wiper trips [45].

For long horizontal wells where slack weight is not available, the solutions' of new designed jar for these wells is made by using the pressure provided through pumped fluid, the jar can be set and fired until the BHA is being released. This eliminates the force need at surface and does not affect the life cycle of the coil. This jar provides very high impact force and by manipulating the pumping pressure with no need to move the CT at surface. The pressure chamber incorporated within the tool allows infinite number of resting and firing until the tool is no longer stuck [41].

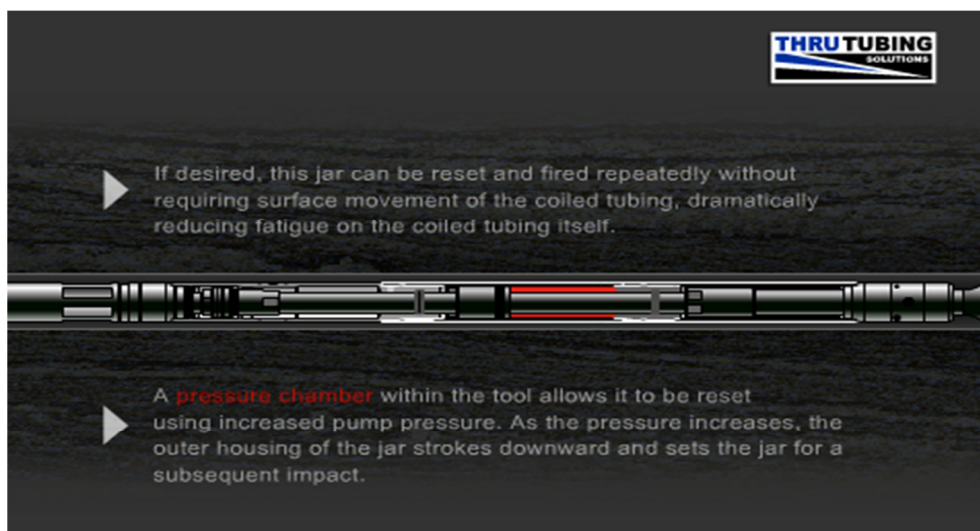


Figure 6-3: HydraSet™ CT Jar [41].

### 6.3 Dynamic Excitation Tool

The objective of this tool is to reduce the static friction acting against the CT and the BHA in order to prevent helical buckling and possibly CT lock up. It improves the weight transfer and enables CTD to extend its horizontal reach. This tool has been tested in Ullrigg test rig in Stavanger-Norway to qualify it for CT operation and to compare the drag forces and the WOB difference with and without the tool included in the BHA. Furthermore, the tool has successfully performed jobs in CTD performed in Alaska and received positive feedbacks from onsite personnel [45].

This tool operates by the mean of converting the pressure pulses created by changing of the flow area into mechanical vibration acting in the axial direction. It consists of short PDM in which its

rotor provides the mechanical movement needed to operate a valve within the tool. This valve is basically made of two plates with holes. The upper plate rotates with the rotation of PDM's rotor while the lower plate is fixed in place. The flow rate will be at maximum value when these two holes are aligned as it is shown in position B in figure 6-4. The flow is then reduced as the flow area reduces by the oscillation of the upper plate. The change in the flow will then create pressure pulses resulting in tool vibration and driving the tool in outward axial direction [45].

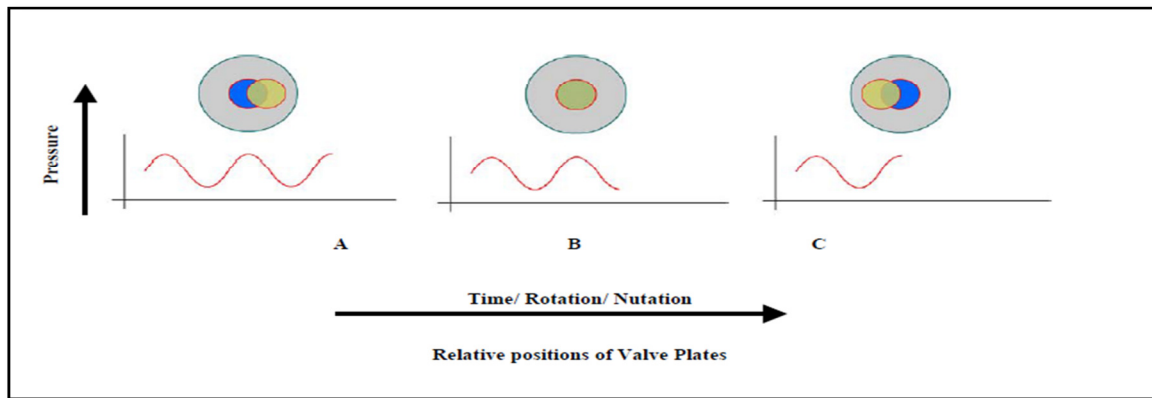


Figure 6-4: Dynamic excitation tool -valve's plate position [45].

### 6.4 Open hole Clad (OHC)

This technology was initially developed to eliminate the risks encountered by unstable formations such as high pressure and/or thief zones associated with re-entry drilling where pressure regime along the well varies significantly [42]. This steel tube can give the mechanical support needed to prevent formation collapse into the wellbore and provide the hydraulic isolation that stops fluid loss in to the formation.

The OHC can be set at any zone along the wellbore without a need to be tied-in into the previous casing [42].

The setting area needs to be under reamed in order to prevent reduction in the hole size. However, the expandable type (Clad-thru-Clad) does not reduce the hole size and therefore, the drilling can be carried out to planned TD with the same bit size [43].

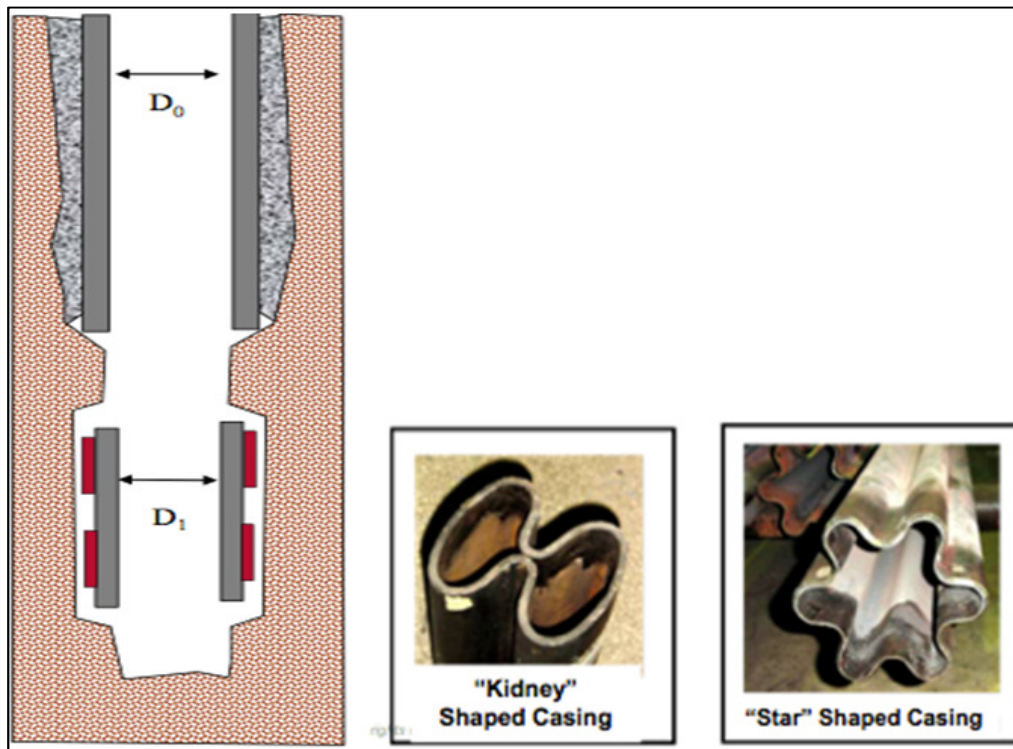


Figure 6-5: Open clad thru clad [44].

The clad is normally set in the area which has been recently drilled. It is run to current well TD and required expansion pressure is applied to initiate the setting sequence [44].

## 6.5 CTD Opportunities in 10 years.

Most of the offshore platforms are accompanied with drilling derricks that can perform the drilling of the new wellbores to reach the new targets. However, this is not possible for the subsea wells which require a mobilizing of MODU to drill the new wells. The efforts are put in place to build light well intervention vessels which are able to pump and handle the hydrocarbons onboard. Skandi Aker is designed with the ability to perform subsea well interventions with both WL and CT [47]. Moreover, the Category B vessels that are developed by Statoil and Aker Solutions with

the intention of targeting subsea wells for future interventions with CT and WL as well as drilling wells by utilizing the TTRD application [48].

As many of these subsea wells will be subjected to CT interventions, there is a potential to drill sidetrack sections and convert them from a single bore well to multi-laterals wells in order to increase the reservoir drainage area. Despite the technical challenges associated with CTD, this can be done in one trip at location. First, the primary intervention operation for the main bore can be done and then drilling the sidetrack section can be initiated by setting a whipstock that has a hole in the main bore and then drilling new sidetrack sections. With the Category B, this can be done with underbalanced drilling (UBD) allowing drilling new laterals without the need for killing the main wellbore.

## 7. CTD compared to Through Tubing Rotary Drilling (TTRD)

Drilling re-entry wells by side tracking from mother wells can also be done using the TTRD technique by utilizing the same equipment used for conventional drilling operation. However, smaller drill pipe size will be needed to be able to pass through to the minimum restriction existed in upper completion. Statoil has performed this application in its fields but it is conducted in Veslefrikk using the Rig Assist Snubbing unit (RAS) together with the rig for the side track drilling conducted in 2003 [26].

Both opportunities and limitations when comparing between CTD and TTRD application can be listed as in the table below:

**Table 7-1 Comparison between Conventional Rotary drilling and CTD [4]**

	Conventional Rotary drilling	Coiled tubing drilling
Package size and movability.	Big and large equipment but usually built in modules	Relatively small portable equipment but coiled tubing reel normally is the biggest piece.
Reliability.	Permanently installed on the rig and more reliable with long history record and experience for continuous operation.	Designed for short time operations and subjected to damages during transportation.
Drilling in underbalanced conditions.	Possible but extra equipment are needed. Operation must stop when making new pipe connection and while tripping in and out of the well	Surface pressure control equipment with continuous tubing provide perfect match for underbalanced drilling operations.

Logging while drilling.	Limited data acquisition due to wireless telemetry communication	Using WL inside CT gives the ability for high bandwidth telemetry feature.
Operational cost	Less expensive than CTD in general	Expensive compared to conventional drilling rigs. Expensive startup cost.
Wellbore cleaning efficiency.	High circulation rate and pipe rotation plus standoff <sup>4</sup> distance provided by pipe joints gives this technique the advantage for hole cleaning.	Hole cleaning is one of the considerations for CTD in deviated and horizontal sections.
Operation safety	Workers need to be present all the time to make connections (working in red zone area).	No need for workers while tripping in and out of hole.
Through tubing operations	Wear consideration and minimum ID in the well can be the limit or show stopper.	Perfect for through tubing drilling when other operational parameters are feasible.
Availability of pull forces at surface and weight on bit down-hole.	Relatively high limit is available at surface due to strong pipe properties.	Weight on bit is one of the considerations for deviated and horizontal section. Less pulling force is available at surface due the CT feature.

<sup>4</sup> Standoff is the distance from the wellbore wall to the pipe body provided by two or more centralizers. In this case, this is provided by the drill pipes joints.



From the table above, we can see the advantages that CTD can offer. These advantages can be identified to be safe working environment, underbalanced drilling and better real time monitoring by using WL telemetry option. It noticeable that CTD doesn't offer better cost saving for a single well project.

Statoil is going to initiate a CTD campaign on other field in the NCS this year. The final results of this campaign will be published accordingly. However, Statoil has acquired very good understanding of implementing TTRD application with rich experience collected in a live best practices document. This document is used to guide the any license drilling team to plan TTRD operation in safe and efficient manner.

For the time being, GF-A will continue utilizing the TTRD for drilling new wells and further consideration might be taken to re-evaluate CTD application as an alternative drilling application.

## 8. Conclusion

Gullfaks as a field was discovered in 1979 with estimated initial recoverable reserve of 2.1 billion barrels. In 2004 the remaining recoverable reserve as a function of time was reduced to 234 million barrels [46].

Drilling re-entry wells using CTD application in parallel to conventional drilling from the rig derrick represents a great opportunity to double the number of wells drilled, and targets more formations to potentially increase the amount of recoverable reserve and extend the field production's life time. TTRD has been the traditional concept for the re-entry application while the CTD is considered at this stage as an alternative approach.

The CTD equipment and best practices were significantly improved since it first started in early 1990s. The improved reliability of CTD application made complex projects to be technically and economically feasible for re-entering old wells and saving the upper completion for efficient cost and time saving by utilizing the CTD application.

The successful project implementation requires proper understanding of the limitations and opportunities of CTD, identifying the governing requirements, evaluate associated risk and reviewing the results so that final objectives can be achieved in an efficient and safe manner.

The economical evaluation of this project did not represent a show stopper as net profit value (NPV) proved its feasibility.

However some operational challenges have been addressed during this study related to well trajectories, lateral length, exit point, hole cleaning, wellbore stability, ROP and available WOB. These challenges are dependent on different variables which need to be optimized in order to obtain the optimal value for each of these variables. For example, the hole cleaning efficiency is dependent on the lateral length, wellbore geometry and drilling fluid density together with the maximum achievable surface pump pressure. In another hand the total lateral length is dependent on CT size which will dictate the maximum available WOB. While the hole stability is highly affected by high mud density. However, drilling a long lateral section will increase the concerns regarding hole cleaning efficiency due to the limitations of maximum achievable flow rate and

pressure at surface which will dictate the annular velocity needed to lift the drilling cuttings to maintain a hole clean.

The Rib Steerable Motor presented in section 6.1 can be included in the drilling BHA to enhance the well tortuosity and obtain a smoother wellbore. This will minimize the friction forces acting on the CT and more WOB will be available. This technology will make drilling longer lateral sections are more likely to be achievable.

However, these, challenges can be prevented during the well design phase or mitigated during the operational execution. It's highly recommended to start with the easiest well that present the minimum technical challenges to build the experience needed for drilling the other wells in this campaign.

As hole stability can be an issue with heavy drilling fluid, the well trajectories are planned to avoid the over pressure Shetland shale. However, Managed Pressure Drilling (UPD) can be utilized after drilling first well in overbalanced condition so that well pressure will no longer be a concern for the weak formations. The new technologies available in the market can offer good solutions needed to prevent or mitigate the operational related risks. The openhole clad (OHC) can be used to isolate over pressured zones that might be encountered along the well path. The experience of utilizing LWD data with CTD operation as discussed from Terengganue offshore – Malaysia can make good impact for active hole condition monitoring and direct the drilling operation based on acquired data realtime.

Moreover, the platform modification can also be carried out by building new deck especially made for CTD surface equipment and with the mud plant based on experience collected from other platform in NCS.

However, the main show stopper for this project was represented by the people onboard capacity for the crew needed to perform the rig modifications and further for the crew needed to perform the CTD operation. The CTD operation was planned to be performed under the responsibility of the intervention team that has a limited allocation of total 18 beds. A total estimated number of 50 crew personnel are needed for CTD campaign assuming that the mud plant is to be run by dedicated crew independent of the drill crew. Therefore, this project is currently not feasible and further studies will not be carried out.

However, CTD application is still a considerable solution whenever the POB is no longer a show stopper. This is due to the advantages that CTD can offer over the TTRD such as fast tripping in and out of the well, drilling and circulating under pressure and continuous downhole telemetry communications. In addition, the CTD is the only application that can fulfill the main objective of initiating this study that aimed to drill re-entry wells independent of the rig derrick in order to increase the total number of wells delivered over the same period of time which is not possible with TTRD.

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APPENDIX A CTD BHAS

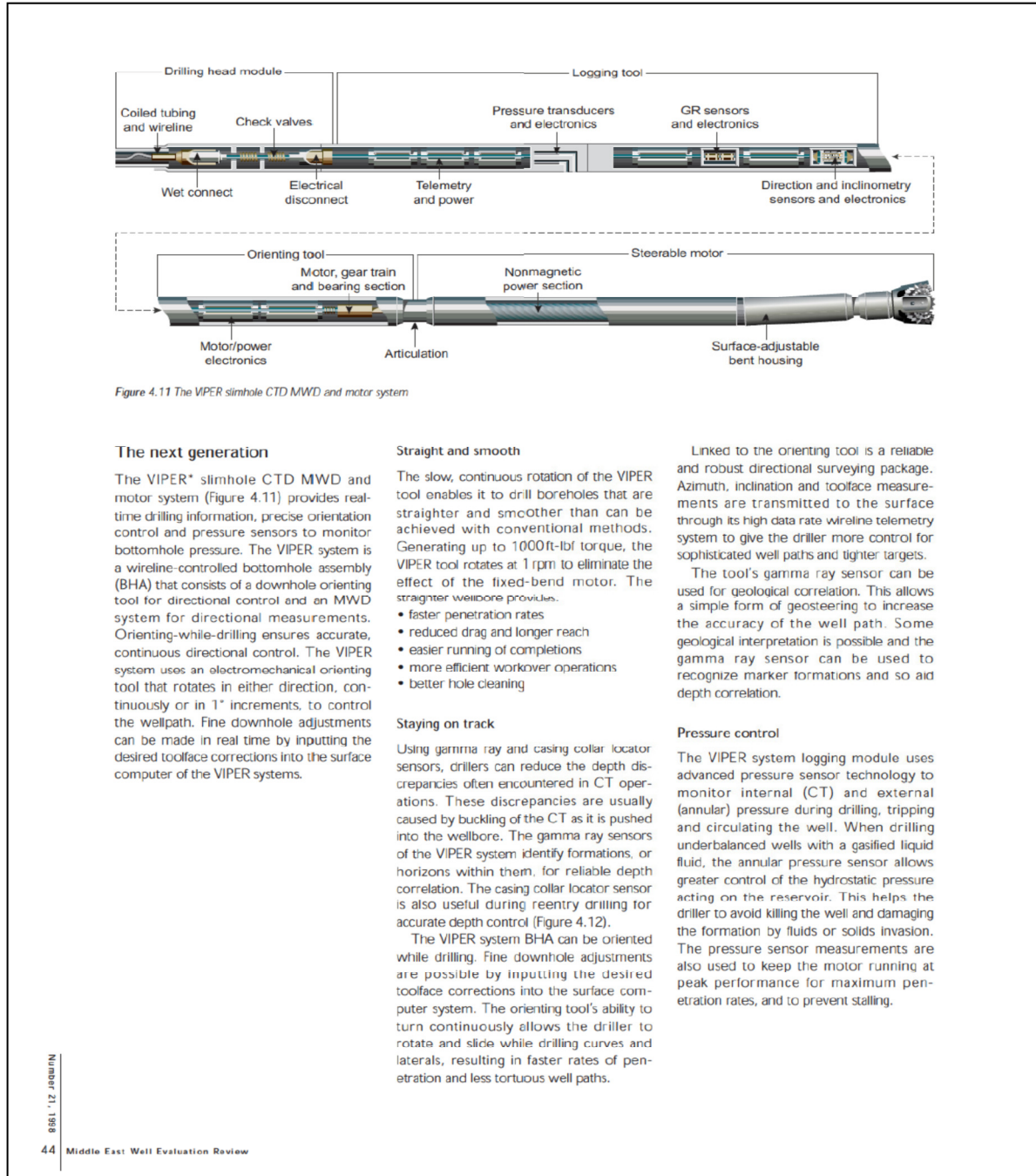


Figure 0-2: VIPER slimhole CTD MWD and motor System [49].

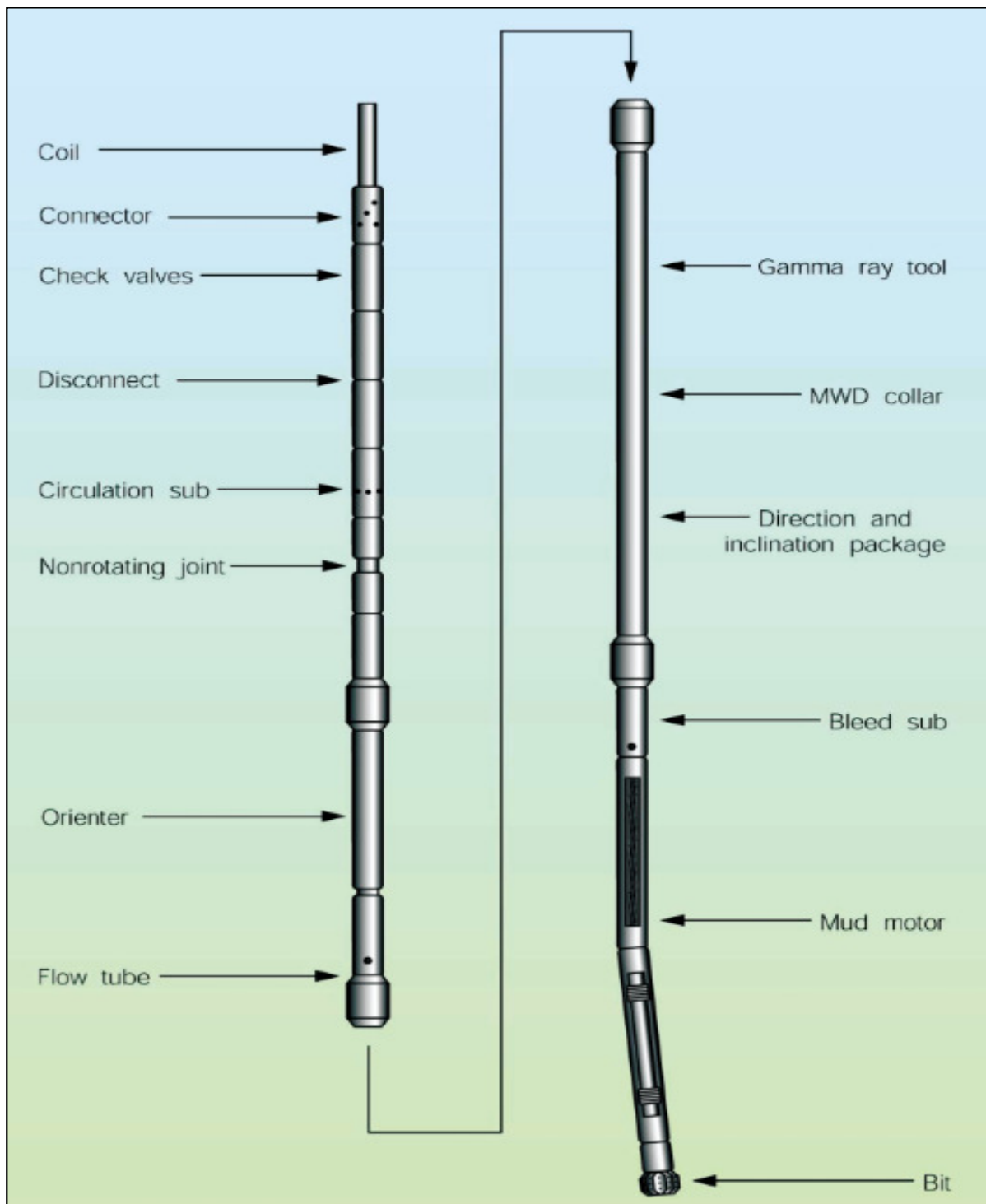


Figure 0-3: CTD basic hydraulically operated BHA [40]

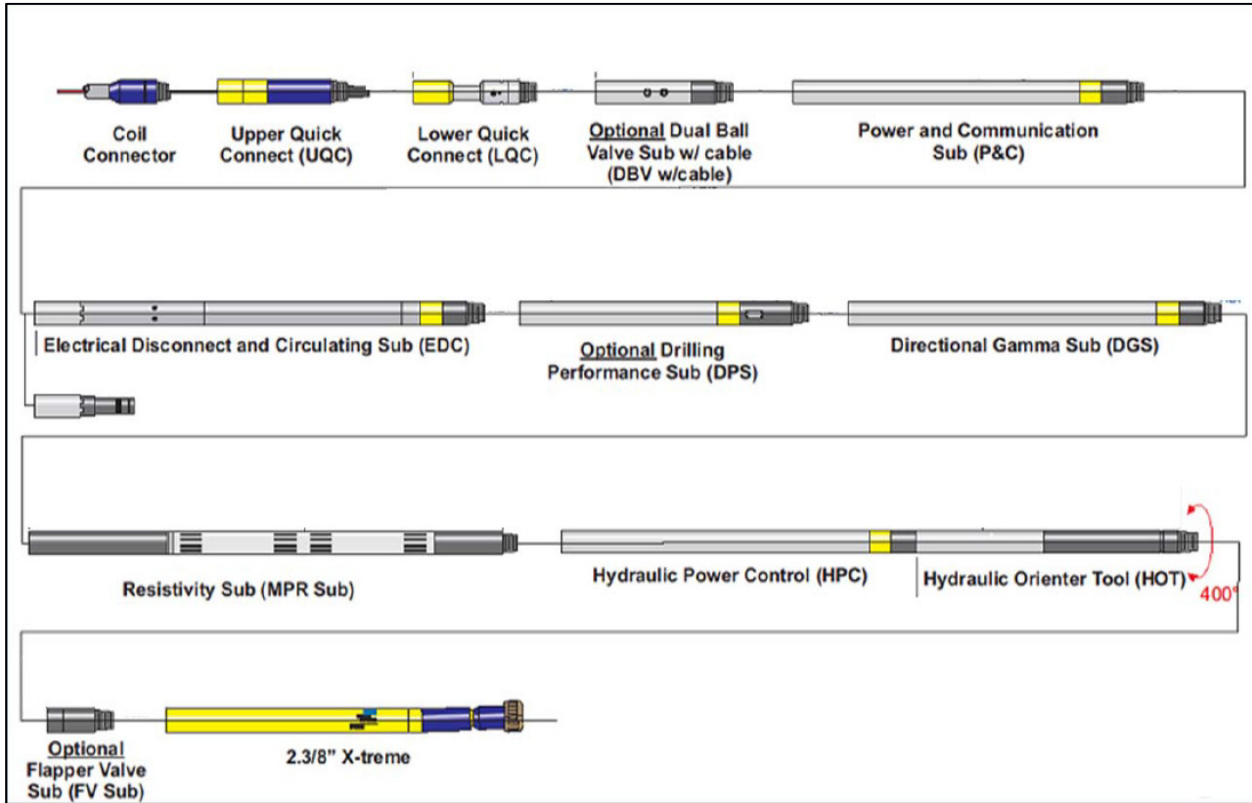


Figure 0-4: 2 3/8" E-line CTD BHA [28]

APPENDIX B CANDIDATES CTD WELLS IN GULLFAKS-A

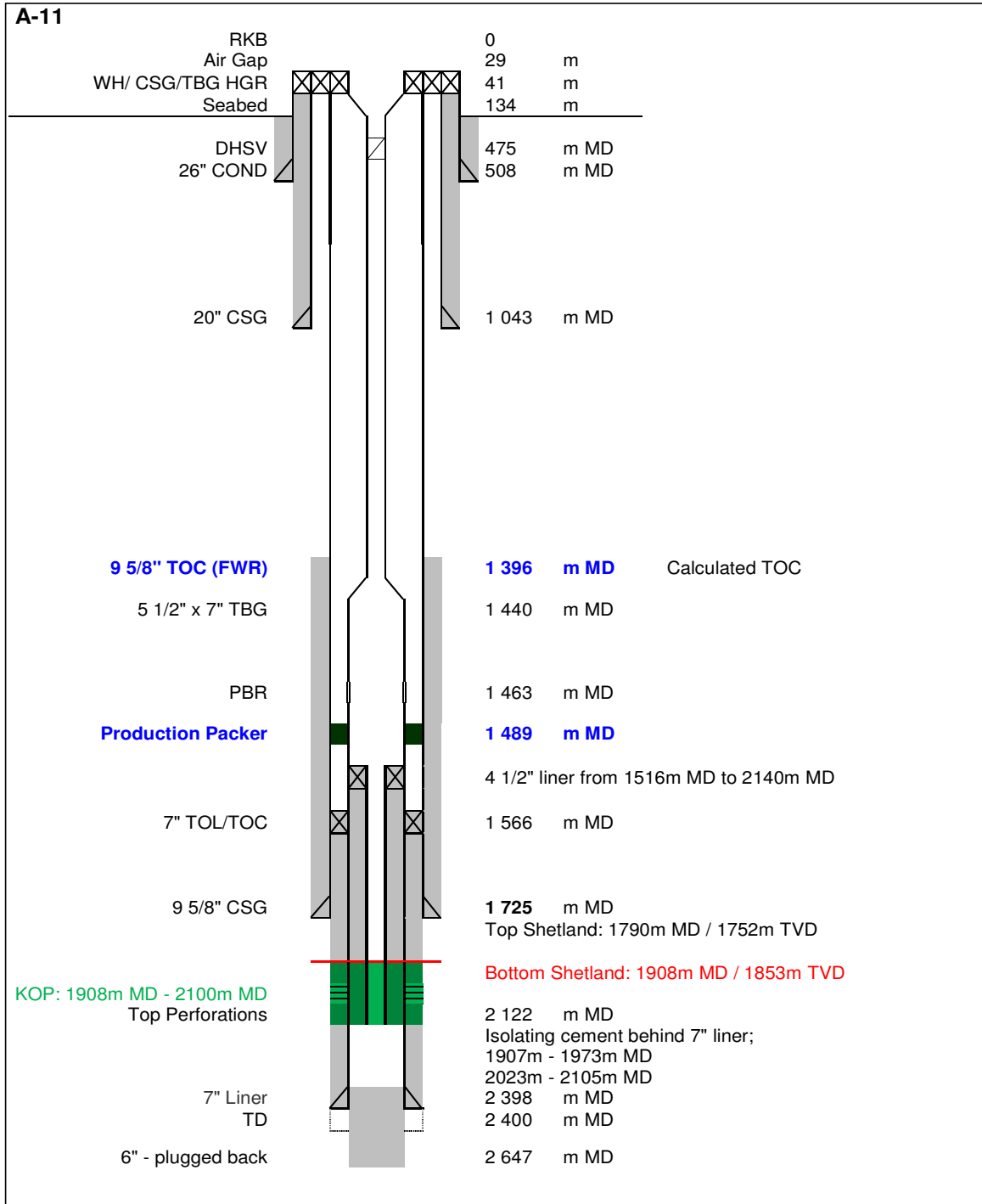


Figure 0-5: A-11 KOP evaluation [25].

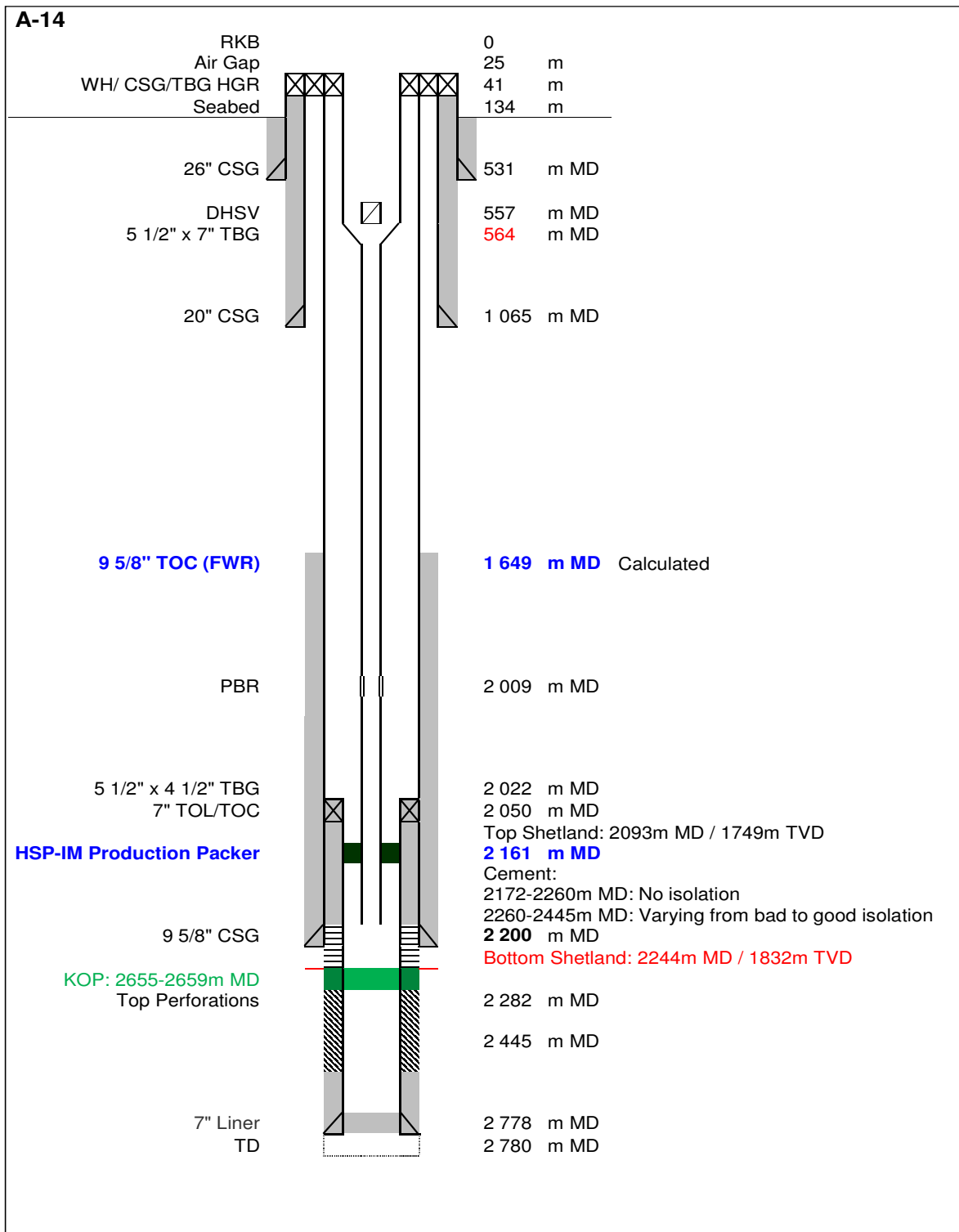


Figure 0-6: A-14 KOP evaluation [25].

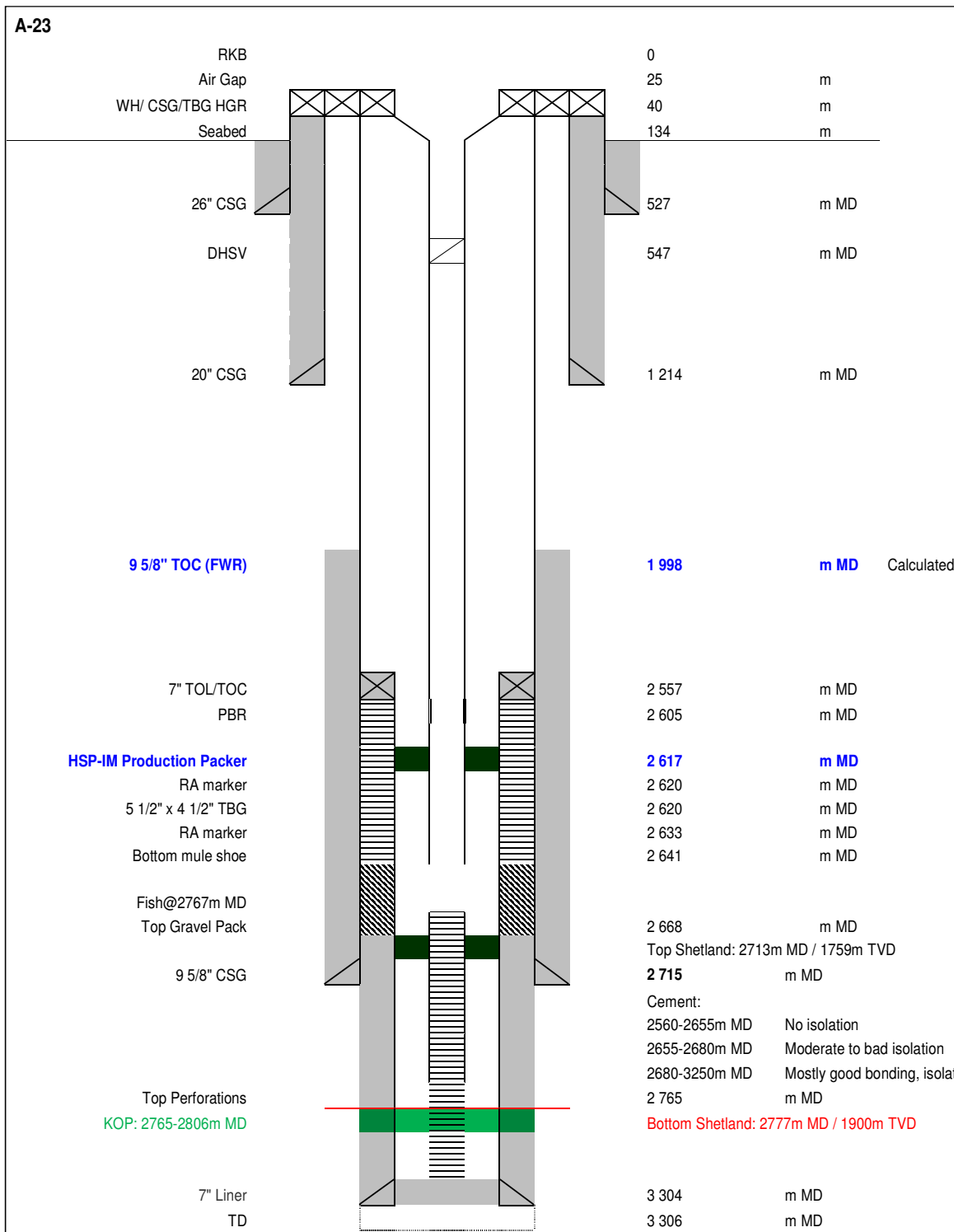


Figure 0-7: A-23 KOP evaluation [25].

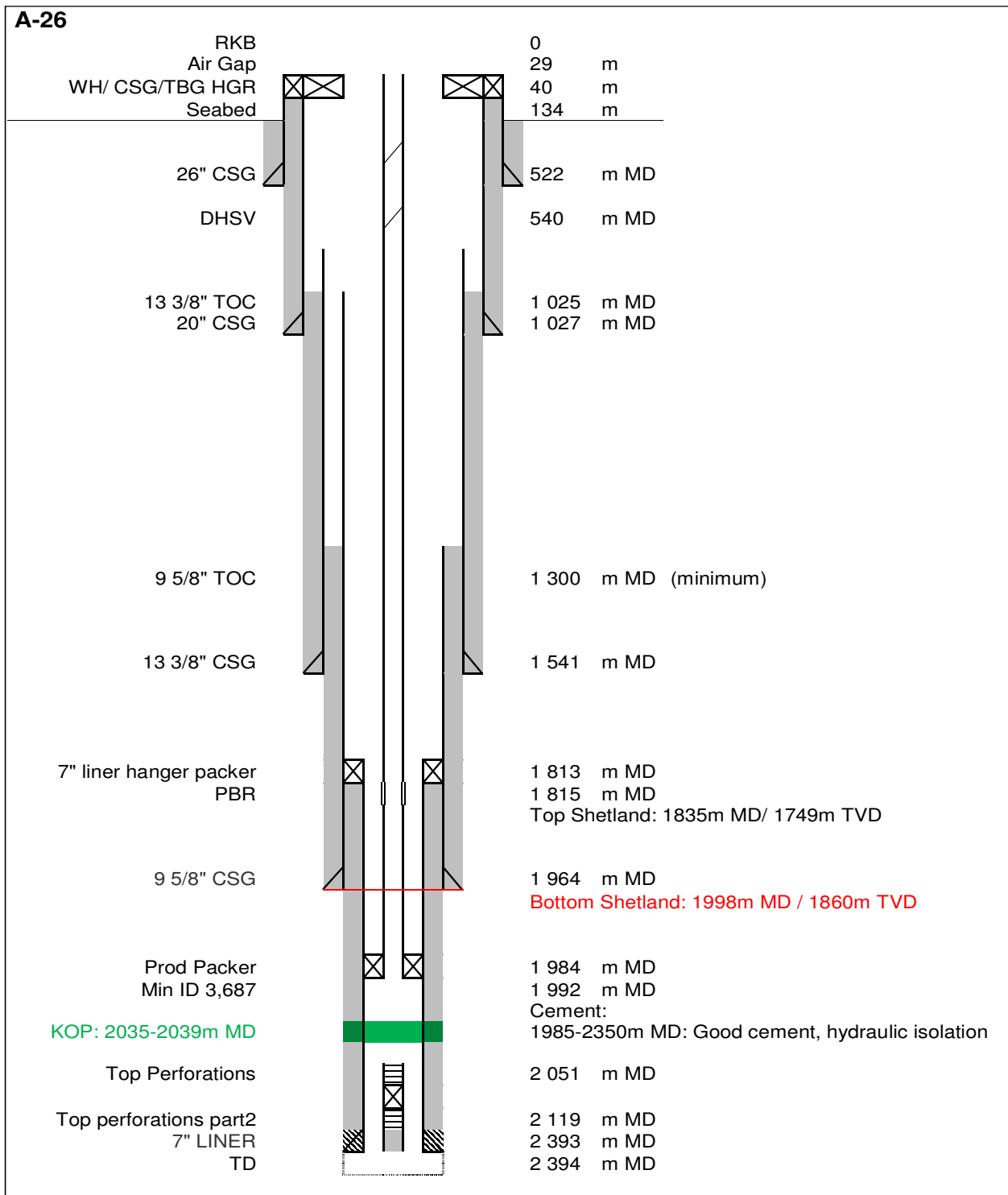


Figure 0-8: A-26 KOP evaluation [25].

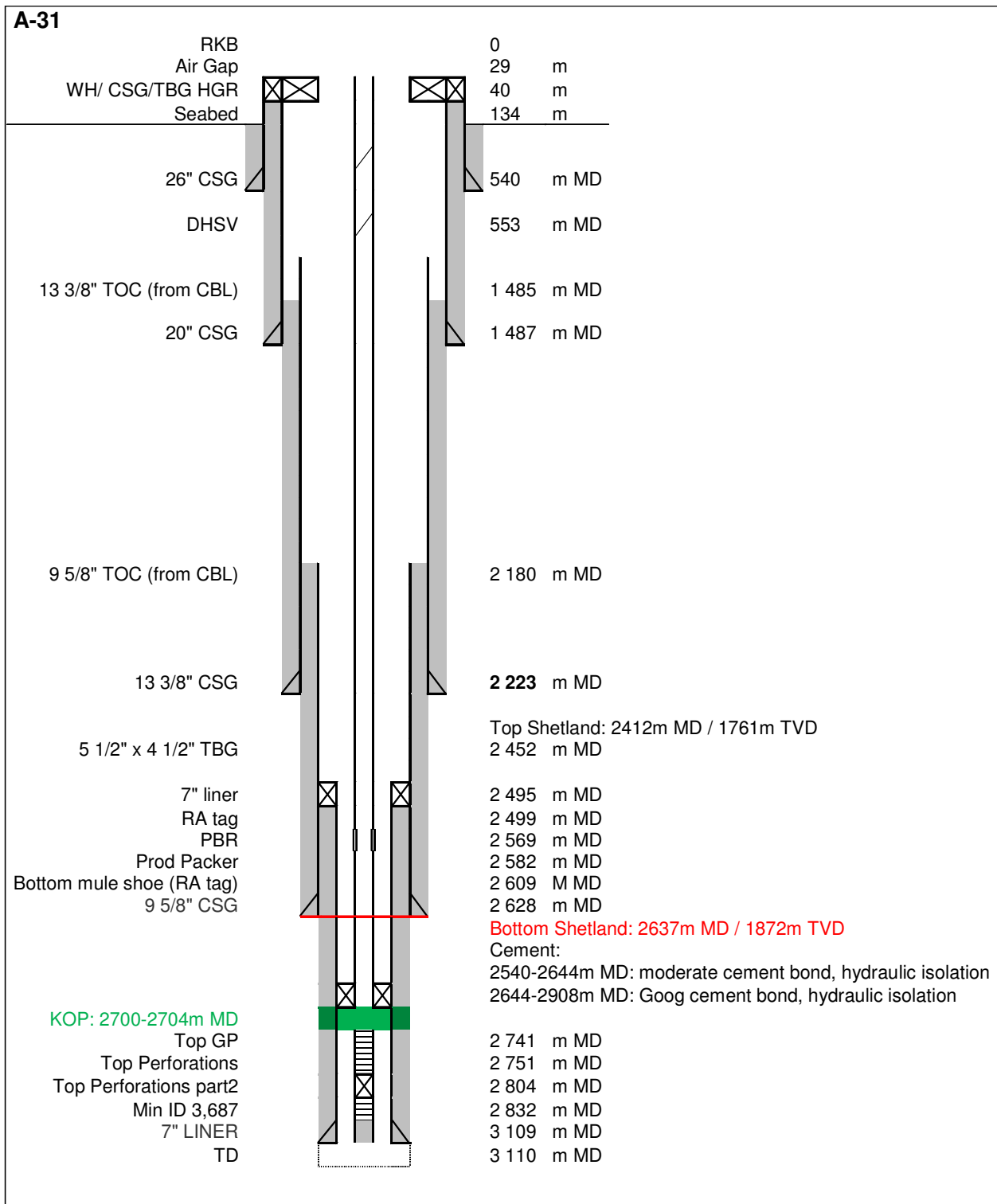


Figure 0-9: A-31 KOP evaluation [25].