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Concentric Coiled Tubing Drilling System

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Summary

A concept review of concentric coiled tubing drilling (CTD) system is performed in this Master thesis, hereafter named DualCTD. The main purpose is to investigate and present the advantages, limitations and applications for the DualCTD system. A feasibility study has been carried out for subsea drilling of drainage holes from an existing well, and drilling of subsea production wells in the Barents Sea.

The DualCTD system consists of two concentric coiled tubing (CT) strings that form a separate circulation system for the drilling fluid. Drilling fluid is pumped down the annulus between the two CT strings to the bottom hole assembly (BHA) where a mud motor generates rotation of the drill bit. The drilling fluid cleans the bit for cuttings and transports the cuttings through a circulating sub/dual float valve and into the inner string. This separated circulating system provides effective hole cleaning from the bottom of the well. The drilling fluid can be a light fluid, that is optimized for hole cleaning capabilities.

A secondary annulus, formed between the DualCTD string and the borehole, is filled with a barrier fluid (BF). Viscous BF is used to separate the two fluid systems in the secondary annulus. Placing the BF in the secondary annuls below seafloor results in an optimized stabilized hydrostatic head. The BF can also be optimized for formation preserving properties. A choke valve in the return fluid line is used to control the back pressure and match the downhole pressure for the two fluid systems with the formation pressure. A light drilling fluid and a heavy BF will also increase the buoyancy of the DualCTD string.

Buckling calculations conducted show that longer horizontal sections could be drilled due to increased buckling resistance and reduced friction drag for the buoyant DualCTD string. Horizontal sections of up to 2300 m can be drilled with a 3,5” x 2,375” DualCTD setup with a 6” bit for vertical kick-off points of 2000 m and deeper. This is more than three times as long as for conventional CTD.

A hydraulic model for calculating the pressure loss in the circulating system is developed. Burst and collapse pressure was found to be limiting for the maximum flow rate due to high frictional pressure loss in the circulation system in deep wells. Cutting transport capacity of the circulation system was found to be low due to the low acceptable flow rates. Cutting transport capacity will therefore limit the maximum rate of penetration.

The DualCTD system will also make it possible to drill through challenging pressure regimes, depleted reservoirs and problematic zones with its unique potential for managed pressure drilling.

Well control approach for the DualCTD concept will be much of the same as in underbalanced-/managed pressure CTD operations The DualCTD blow out preventer needs to be verified for cutting of the DualCTD string. Running of casing and cementing operations may have to be performed on drill string due to the large weight of the casing and the low axial load capacity of the DualCTD string.

Significant development work is needed to bring the DualCTD to a field proven method

Sammendrag

En konsept gjennomgang av et konsentriskkveilerørsboresystem (CTD) er utført i denne Masteren, heretter kaldt DualCTD. Hovedformålet er å undersøke og presentere fordeler, begrensninger og anvendelser for DualCTD systemet. En mulighetsstudie er utført for boring av dreneringshull fra en eksisterende undervannsbrønn og boring av undervannsproduksjonsbrønner i Barentshavet.

DualCTD systemet består av to konsentriske kveilerør (CT) som danner et separat sirkulasjonssystem for borevæsken. Borevæsken pumpes ned gjennom ringrommet mellom de to kveilerøren, ned til bunnhullsenheten (BHA), hvor en slammotor genererer rotasjon av borekronen. Borevesken renser borkronen for borekaks og transporterer borekaksen gjennom en sirkuleringsport og inn i det innerste kveilerøret. Det separate sirkulasjonssystem gir effektiv hullrensing fra bunnen av brønnen. Borevæsken kan være en lett væske, som er optimalisert for hullrensing egenskaper

Et sekundært ringrom dannes mellom DualCTD strengen og borehullet. Dette fylles med en barrierefluid (BF). Tyktflytende BF blir brukt til å separere de to væskesystemer i det sekundære ringrommet. Separat BF i det sekundære ringrommet resulterer i en optimalisert hydrostatisk fluid kolonne tilpasset formasjons trykket i brønnen. BF kan i tillegg optimaliseres for formasjons bevare egenskaper. En strupeventil i retur røret til borevæsken benyttes for å styre mottrykket på borevæsken for å samsvarer dette med nedi hulls trykket for de to væskesystemer. En lett borevæske og en tung BF vil også øke oppdriften av DualCTD strengen.

Bukling beregninger som er utført viser at lengre horisontale seksjonene kan bli boret på grunn av økt bukle motstand og redusert friksjons motstand for DualCTD strengen. Horisontale seksjoner på opptil 2300 m kan bores med en 3,5 "x 2375" DualCTD oppsett med en 6 "bit for kick-off dybder på 2000 m, og dypere, fra vertikale brønner. Dette er mer enn tre ganger så lang som for konvensjonell CTD.

En hydraulisk modell for å beregne trykkfallet i sirkulasjonssystemet er utviklet. Burst og kollaps tykk ble funnet å være begrensende for maksimal strømningshastighet på grunn av det høye friksjonstrykktapet i sirkulasjonssystemet i dype brønner. Borekaks transport kapasiteten til sirkulasjonssystemet ble funnet å være lav på grunn av de lave akseptable strømningsratene. Borekaks transportkapasiteten vil derfor være begrensende for den maksimale borehastigheten.

DualCTD systemet vil gjøre det mulig å bore gjennom utfordrende trykkregimer, trykk avlastede reservoarer og problematiske soner med sitt unike potensiale for trykkbalansert boring.

Brønnkontroll tilnærming for DualCTD konseptet vil være mye av det samme designet som i underbalansert-/trykkbalansert kveilerørsboreoperasjoner. DualCTD utblåsningsventilen trenger å bli verifisert for kutting av DualCTD strengen. Kjøring av foringsrør og sementeringsoperasjoner kan måtte bli utført ved bruk av borestreng, på grunn av den store vekten av foringsrøret og den lave aksiale bæreevnen til DualCTD strengen.

Betydelig utviklingsarbeid er nødvendig for å bringe DualCTD konseptet fra konseptstadiet og til en utprøvd bore metode.

Acknowledgements

I would like to thank Professor Sigbjørn Sangesland for the opportunity to write this Master thesis under his guidance, and also for his feedback and support when needed.

It has been a great experience for me to work with a new concept that can have a potential impact for the future of oil and gas drilling.

Regards,

Håkon Sandven

June, 2014

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1. Introduction

Oil and gas will be an important part of the world's energy demand in many generations to come. To meet up with the increased demand, new fields need to be found and developed. It is also important to improve the recovery factor from already existing fields. One of the solutions to improve oil recovery is to drill new wells into undrained parts of the reservoir and/or drill injection wells. Drilling is one of the most capital intensive operations in oil and gas extraction. With today's low oil price, new cost saving solutions for drilling operations needs to be developed.

In this Master thesis The DualCTD system is reviewed, with a goal to reduce the cost of new wells by performing the drilling operations from lower specification drilling/intervention vessels. The DualCTD system is also intended to drill through challenging pressure regimes, depleted zones and loss zones. The DualCTD system consists of a coiled tubing (CT) inside a larger CT. A separated circulation system will be formed in the annulus between the two CT strings and inside the inner CT string. This separated flow conduit is intended to solve some of the challenges with coiled tubing drilling (CTD), which involve bad hole cleaning and low resistance to buckling.

State of the art technology on dual circulation systems are reviewed to find technical aspects and solutions that can be implemented in the DualCTD system. Advantages, limitations and applications for the DualCTD system are examined. A hydraulic model is developed with a basis from the literature in the theory part. Hydraulic simulation programs available to the author were not possible to modify to calculate the pressure drop for the DualCTD system. The hydraulic model is used to calculate the frictional pressure drop for the concentric DualCTD system for the given string setups, flow rates, fluid rheology's and well paths. Results from this model are compared with burst and collapse pressures simulations for the DualCTD strings to find an optimum string setup and flow rate. Hole cleaning velocities and maximum cutting carrying capacity for the DualCTD setup is used to calculate the corresponding maximum rate of penetration (ROP) for the system.

SI units are used in the majority of the calculation in this master thesis. However, oil field units are used where it is convenient.

This thesis aims on presenting the advantages, limitations and applications for the DualCTD system.

2. Background theory

2.1. Conventional Drilling

Rotary drilling became the preferred penetration method for drilling oil and gas wells in the middle and late 20^{th} century. Since then the principle has stayed the same.

Conventional drilling is performed by use of a drill string and a Bottom Hole Assembly (BHA) with a drill bit. The drill string consists of single drill pipes threadingly connected. The principle is to rotate the bit from surface to grind and cut the rock. The cuttings created are then removed by a fluid system, mud, which is circulated down inside the rotating drill pipe, through the bit and up the annulus. After the hole is drilled it has to be cased, to keep the hole stable and open.

2.1. Drilling Pressure Windows

The pressure from the mud column in conventional drilling has to stay within the formation pressure drilling window. The drilling window is determined by the formations pore- and fracture pressure, illustrated in green color in Figure 2-1. To be able to stay between the pressure limits and reach the given target depth of the well, the drilling process has to be done in several stages. Drilling engineers has to makes a casing program with different casings to seal off different pressure zone downhole, to be able to reach the final depth. The open circulation system that is used in conventional drilling is called overbalanced drilling. Overbalanced drilling has been suitable for most drilling operations up to date, but when pressure profiles starts to get abnormal, overbalanced drilling is no longer the right tool to use. As of today when the “easy” oil is extracted and the business needs to look other places to find the oil, more complex pressure profiles occur. Deepwater drilling, depleted fields, loss circulation zones etc. are cases that need other drilling solutions to be able to performed the operations in a safe and efficient manner. Underbalanced operations (UBO) and managed pressure drilling (MPD) are the solution to some of these problems. Figure 2-1 illustrates the different drilling pressure windows:

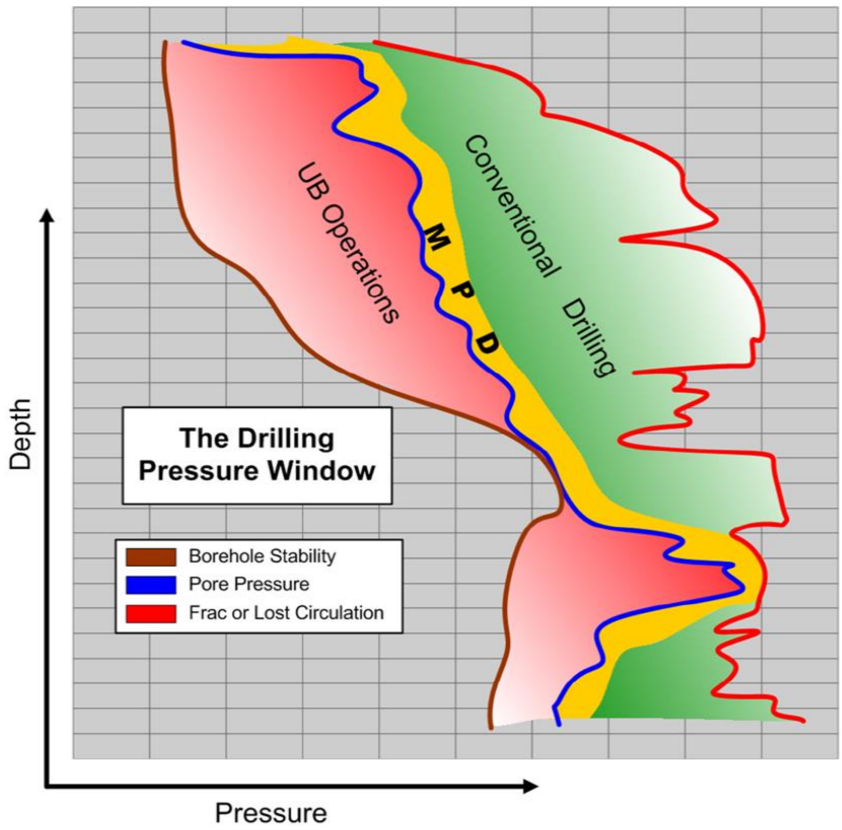


Figure 2-1 Drilling pressure windows (Eck-Olsen 2014)

2.1.1. Under Balanced Operations

In UBO operations the hydrostatic head of the drilling fluid is intentionally designed to be lower than the pore pressure of the formation being drilled, illustrated with red color in Figure 2-1. This may result in influx of formation fluids which must be circulated out and separated at surface (Eck-Olsen 2014). UBO is used in many drilling operations on land in USA and Canada, it has also been performed with success offshore in Norway. UBD operations eliminate many of the problems that can occur when drilling conventional, some of the advantages are: better well control, it induce less formation damage in the reservoir zone, eliminates differential sticking, solves expensive loss circulating situations, increase ROP in hard formations and increased bit life. Earlier production and producing while drilling are also favorable. Pressurized surface facilities for separation of drilling fluid, formation cuttings and produced reservoir fluid is needed. New hazards and challenges related to well control is introduced with UB operations. The mud column as primary barrier is replaced by a mechanical rotating control head barrier and high pressure lines at surface. Working on live wells in UB operations require extra equipment, good planning, high focus on safety and good training of experienced rig crew (Eck-Olsen 2014).

2.1.2. Managed Pressure Drilling

MPD operation was developed for the need of a near balance drilling technology. It got its name and was given its own identity around 2003. MPD is an adaptive drilling process where the annular pressure profile is precisely controlled throughout the wellbore. With the intention to avoid continuous influx of formation fluid to surface, any influx will be circulated out and threated accordingly with appropriate surface equipment. The objective is to manage the annular hydraulic pressure profile and ascertaining the downhole pressure environment limits. Figure 2-1 illustrates the MPD pressure window, illustrated in yellow color, situated between the pore and fracture pressure and sometimes close to the borehole stability limit (formation breakdown limit). MPD is used in drilling of wells with narrow downhole pressure limits, by applying tools and techniques to mitigate the risks and cost with these operations. MPD can mitigate drilling problems as: stuck pipe, lost circulation, wellbore stability, well control etc. MPD includes control of many drilling parameter as: back pressure control, fluid density, fluid rheology, annular fluid level, circulating friction, hole geometry, or a combination of these (Eck-Olsen 2014). MPD requires more well control equipment, MPD subcontractors with equipment and highly skilled and trained rig crew to be performed in a safe and secure manner. MPD can also extend sections or eliminate casing points, this is described more in Chapter 3.

2.2. Coiled Tubing

Coiled tubing (CT) is a long flexible steel pipe string reeled around a large drum for storage, transport and deployment. The CT has one continuous longitudinal seam, electric-welded with high-frequency induction welding. Coiled tubing can be used in various well intervention operations, coiled tubing drilling (CTD) and pumping operations (PetroWiki #1 2015). Normal CT string diameter ranges from 0.75 in. to 4 in. and single strings with lengths up to 30 000 ft. have been manufactured (ICOTA 2005). Today, the CT industry is one of the fastest growing segments in the oil service sector.

2.2.1. History of CT

The first CT technology was the PLUTO, an acronym for “Pipe Lines Under the Ocean,” project during the 2nd world war. This was a top-secret effort initiated by Churchill to install pipelines across the English Channel, from England to France. Several pipelines were installed to provide fuel for the D-day invasion. Most of the pipelines were made up by butt welding 40 ft. (12m) long, 3in diameter steel pipes together to form continuous pipes. The steel pipe sections were welded end to end and a cable-lying vessel towed floating drums with the steels pipes spooled on. 23 pipelines were successfully deployed, ranging from 48 to 113 km. This project, with its success of fabrication and spooling of a continuous flexible pipeline, is said to be the foundation of future technical development and use of CT that is used in oil and gas wells (Schlumberger Oilfield Review 2004).

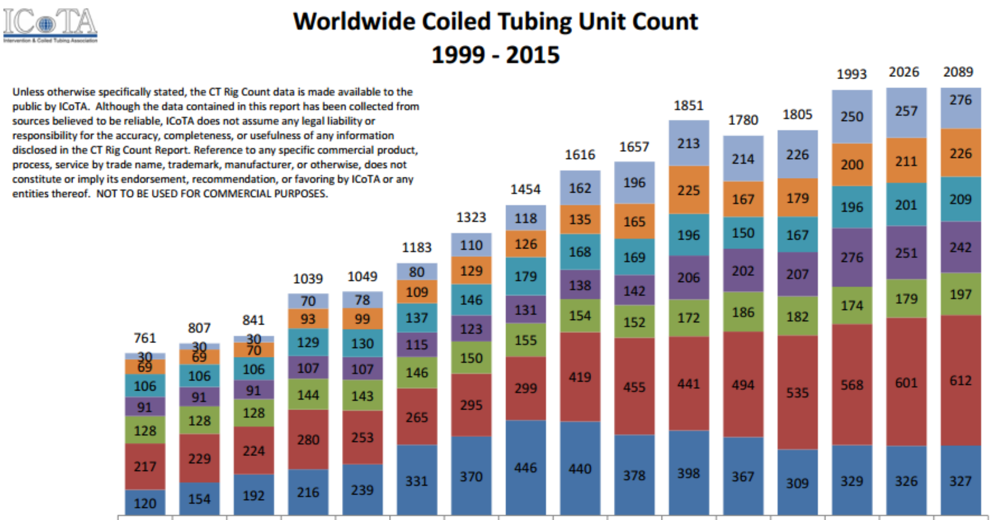
Figure 2-2 Laying Pluto in August 1944 after D-Day (beingbutmen.blogspot.no/)

The first fully functional CT unit was built by Bowen Tools and the California Oil Company in 1962. The purpose of this CT application was to wash out sand bridges in oil wells. In the beginning, CT was considered as high-risk operations and only applicable for niche services. The quality of the steel was poor, with low yield strength and together with all the end-to-end welds required to fabricate long continuous pipes, the tubing was not able to withstand high tensile loads and repeated bending cycles when spooling on and off the reel. Operators lost confidence in this technique with all the well failures, equipment breakdowns and fishing operations. In the late 1980's a new bias welding techniques was introduced and the used of Japanese steel sheets with better quality, and length up to 3000 ft., improved the reliability of CT. In the 1990's CT got its revolution when higher strength steel pipes with larger diameter were introduced (Schlumberger Oilfield Review 2004).

Today CT is has grown beyond its typical well cleanout and acid stimulation application. The CT operations today range from wellbore cleanouts, well unloading, jetting with inert gases or light fluids, perforation, acid or fracture stimulations and sand-consolidations treatments, cementing, fishing and milling, well logging, setting and retrieving plugs, under reaming and drilling (Schlumberger Oilfield Review 2004) (ICOTA 2005).

2.2.2. Coiled Tubing Rig Count

The number of available CT units in the world is showed in Figure 2-3. This illustrates the increase in the use of CT in the oil industry in the world the last 15 years. The 761 available CT units on the market in 1999 are nearly tripled to todays 2089 units!



	1999	2000	2001	2002	2003	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Annual Total	761	807	841	1039	1049	1183	1323	1454	1616	1657	1851	1780	1805	1993	2026	2089
Russia & CIS	30	30	30	70	78	80	110	118	162	196	213	214	226	250	257	276
Far East	69	69	70	93	99	109	129	126	135	165	225	167	179	200	211	226
Middle East	106	106	106	129	130	137	146	179	168	169	196	150	167	196	201	209
Latin America	91	91	91	107	107	115	123	131	138	142	206	202	207	276	251	242
Europe/Africa	128	128	128	144	143	146	150	155	154	152	172	186	182	174	179	197
USA	217	229	224	280	253	265	295	299	419	455	441	494	535	568	601	612
Canada	120	154	192	216	239	331	370	446	440	378	398	367	309	329	326	327

Figure 2-3 Worldwide Coiled Tubing Unit Count 2015 (ICoTA 2015)

2.2.3. CT Benefits

CT was initial developed to work on live wellbores, later CT has shown advantages in many other ways. Rig up time and footprint on land is relatively small compared to conventional drilling, this has made CT more attractive for drilling and workover applications. Some of the key benefits with CT technology are as follows (ICOTA 2005):

- Safe and efficient well intervention
- Ability to work on live wells, no need to shut down the well
- Fast mobilization and rig-up on land
- Continuous circulation while Run In Hole(RIH) and Pull Out Of Hole (POOH)
- One continuous pipe requires no stop for connections, reduces trip time and results in less no productive time (NPT)
- Less crew/personnel is needed compared to conventional drilling
- Use of CT for the right applications will significantly reduce cost

2.2.4. Equipment

An offshore CT rig up on Gullfaks C is showed in Figure 2-4. This CT operation is run by Baker Hughes and all of the equipment is their assets. The equipment is shipped offshore in containers and installed on site. CT operations is fast to rig up on land jobs, but typical rig up time for an offshore CT operation takes from 5-15 days. This is a very long NPT. This is why CT is rarely used on the Norwegian continental shelf these days.

Figure 2-4 Baker Hughes CT rig up on Gullfaks C, Photo by Magnus Wingan Wold

Key elements necessary to perform standard CT operations are highlighted in Figure 2-4 and consist of:

- Tubing reel – Transport and storage of the CT
- CT inspection device – Inspects tubing for damage and ovality
- Gooseneck – Guides the CT into the Injector head
- Injector head – To provide the surface drive force to overcome the well pressure when injecting the CT into a live well, it is also used to retrieve the CT from the well
- Dual stripper – Well control equipment, primary barrier
- CT blow out preventer (BOP) – Well control device with rams, secondary barrier
- High pressure Riser – Riser from top of the christmas tree to the CT BOP
- Control Cabin – Monitoring and operating of the CT system

- Power Pack – Hydraulic and pneumatic power generation to operate the CT unit.

2.2.5. CT Mechanical Performance

The CT string is made with the purpose of being plastic deformed when spooled on and of the tubing reel and when guided over the gooseneck. Plastic deformation of the material in the CT string inflicts fatigue on the string every time it is spooled on and off the reel. Fatigue accumulates over time and will eventually cause the string to crack, resulting in CT string failure (ICOTA 2005).

"Plastic deformation can be described as deformation that remains after the load causing it is removed. Fatigue can be defined as failure under repeated or otherwise varying load, which never reaches a level sufficient to cause failure in a single application." (ICOTA 2005)

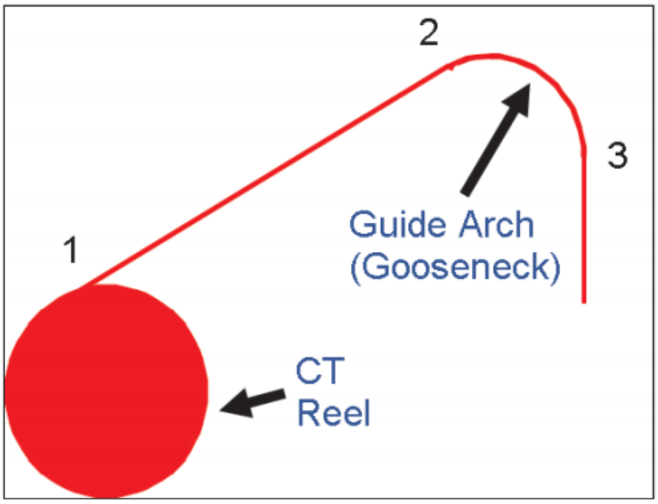


Figure 2-5 CT Plastic deformation points (ICOTA 2005)

Figure 2-5 shows where the string is plastically deformed under standard CT operations. When the CT is spooled of the tubing reel, the string is straightened out in point 1. It is then bent and deformed when guided into the gooseneck in point 2. At point 3 the CT is straightened out again before entering the injector and into the wellbore. The same sequence recurs and the CT gets plastically deformed when POOH (ICOTA 2005).

Fatigue has to be carefully monitored and the CT is inspected every time it's spooled on and off the tubing reel. The CT inspection device inspects the tubing for any damage, ovality or any other geometry change. The operation is stopped immediately if any deviations from give tolerances are found. The life time of each CT string is simulated and monitored by the CT service companies. This allows the CT service companies to replace the CT strings long before failure. Failure of the CT string under operation can cause fatal consequences to equipment, environment and even humans. Fishing and repairing a broken CT will lead to long NPT and cost a lot of money.

2.2.1. Welding and Splicing of the CT String

The CT string can be welded or spliced together at the site. This can be done for various reasons; repairing a damaged pipe, butt welding of two pipes for increased length, connecting downhole tools, etc. The area of the CT around a weld will be physically different from the other material of the string, because a heat affected zone is formed, see Figure 2-6 below. CT service companies have their own methods for welding pipes and simulations are performed to certify the welds for loadings.

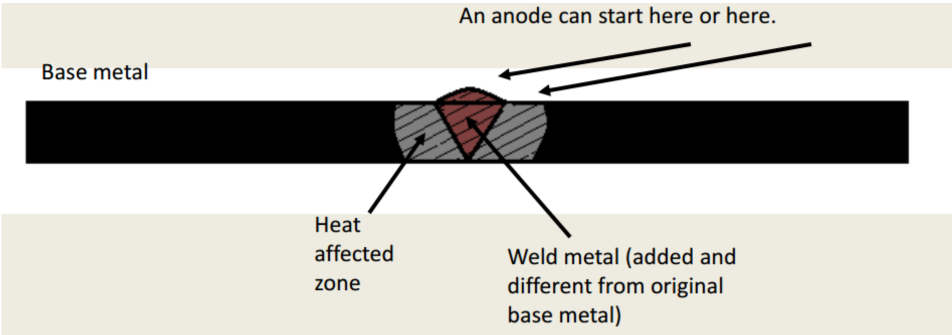


Figure 2-6 CT weld and forming of an anode (King 2009)

Baker Hughes spliced together a CT string for Statoil's CTD campaign on Heidrun. The CT string was cut in half and transported in two reels because of the limited lifting capacity of the offshore cranes. Baker Hughes 2nd generation spool-able DuraLink™ CT connector performed extremely well and no premature change-out of connector happened. This patented method is facilitated for pass-through of wireline cutter. This is extremely important to be able to recover a stuck CT (Statoil ASA 2014). Final element analysis of the DuraLink CT connector is illustrated in Figure 2-7, this shows the stresses during bending simulations of the connector.

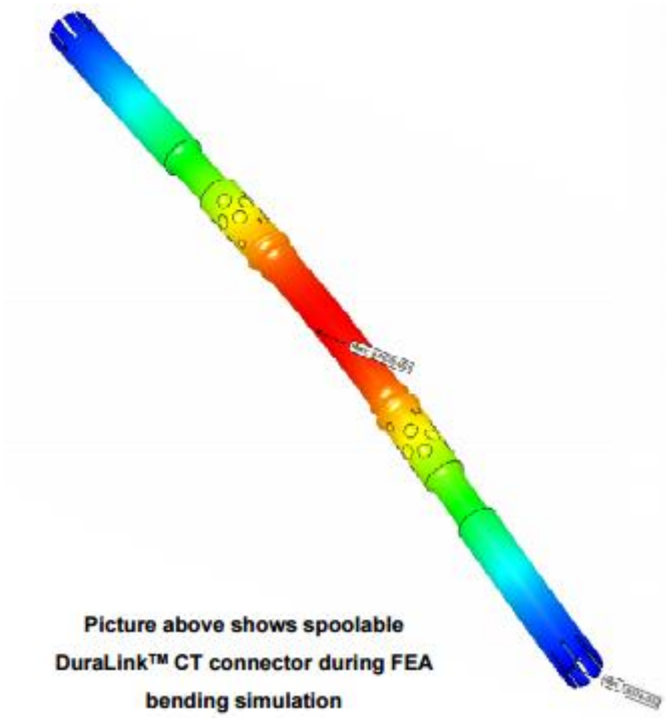


Figure 2-7 FEA of the DuraLink CT connector (Statoil ASA, 2014)

2.2.2. CT Well Control

One of the advantages with CT is its ability to work on live wells. The presence of surface wellhead pressure under CT operations put great demands on the well control equipment and an overall high focus on safety. The well control equipment in CT operations is installed and stacked on top of the Christmas tree.

In Figure 2-8 illustrates a typical well control set up for an offshore CT rig-up. In NORSOK D-010, surface well barrier acceptance criteria for CT operations in completed wells on the Norwegian continental shelf are listed as (Standards Norway 2013):

- 2x CT stripper
- CT BOP
- High pressure riser
- CT safety head

Figure 2-8 CT rig up on Gullfaks A. Photo by Magnus Wingan Wold

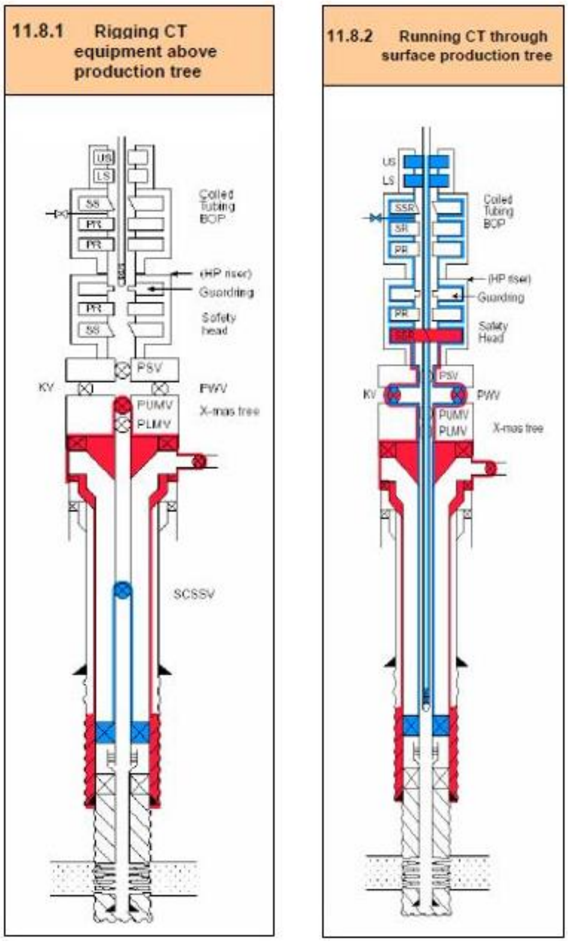


Figure 2-9 CT Barrier drawings (Standards Norway 2013)

The Safety head is installed on top of the Christmas tree shown In Figure 2-8. This element consists of a BOP body with shear/seal ram and a riser connection, its purpose is to prevent flow from the wellbore in case of loss or leakage in the primary well barrier. A high pressure riser is connected to the safety head and extends all the way from the wellhead deck to where the CT BOP is located in the CT rig up.

The CT BOP is connected on the top of the riser. It consists of a BOP body with a slip ram that is able to grip and hold the CT, a CT annulus seal element/pipe ram, a shear ram that can cut the CT string, a seal ram to seal the wellbore after the CT is cut and a kill inlet connection to circulate out the overpressure in the well. The CT BOP is the secondary well barrier and it should prevent flow from the wellbore in case of failure of the CT string or in the stripper. It should also be able to shut down and close the well bore if an unexpected blow out occur. The 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 pipe ram has been activated, to kill the well. (Standards Norway 2013).

The CT stripper is the primary well barrier. It provides a pressure seal between the wellbore and the atmosphere, while letting the CT run in and out of the well. The pressure rating shall exceed the maximum differential pressure that it can be exposed to, including a margin for killing operations. The hydraulic pressure from the stripper shall be as low as possible to avoid excessive friction, but sufficient to maintain a dynamic pressure seal (Standards Norway 2013).

Figure 2-9 shows examples of the barrier drawings from NORSOK while rigging and running CT. Rigging of a CT operation is done on top of the Christmas tree, shown here as a vertical tree and the well barriers are the standard well barriers under production/injection with the Christmas tree as the secondary and SCSSV (Surface controlled subsurface safety valve) plus the packer as the primary barrier. When the rig up is completed and running of CT starts, barrier situation is changed. The right part of the figure show how the strippers act as the primary barriers and how the Safety head act as the secondary barrier in CT operations.

2.3. Coiled Tubing Drilling

Coiled tubing drilling (CTD) has been used to construct thousands of vertical and directional wells since the beginning of 1990's. CTD has been used successfully in regions as Alaska, Canada, Venezuela and the Middle East, but it's still considered as an immature new technology and its full potential has not yet been fully utilized in other markets (PetroWiki #1 2015). Hybrid coiled tubing rigs was introduced in 1997, they made it possible to drill conventionally and by CTD from the same rig, to utilize both methods potential.

2.3.1. History

Coiled Tubing Drilling (CTD) has its origin dating back almost 100 years. Cullen Research Institute developed the first commercial CTD rig in 1964. The first big steps in CTD techniques were taken in the 1970s, the experimental drilling operations conducted at this time had mixed results and several technological advances were required to make the CTD technique effective, reliable and commercial (Schlumberger 1998).

The first commercial system was developed by the Canadian company, FlexTube in 1976 (AnTech 2015). FlexTube drilled 16 vertical, non-steered, shallow gas wells in Canada in two years. The deepest well was around 1700ft, drilled with a 2 3/8 in tubing, drill collars, a 5 in. downhole PD motor and a 6 5/8 in. tricone bit. The purpose of this project was to find cheaper ways to drill wells, compensate for the escalating pipe prices, reduce the expensive handling equipment required in normal drilling operations and reduce the manpower needed to drill.

However, the CT tubing and equipment proved to cost as much, or even more, than conventional drilling equipment and cost savings with CTD was not immediately proven. The project was later terminated due to these reasons and the lack of industry recognition and sponsorship (PetroWiki #2 2015).

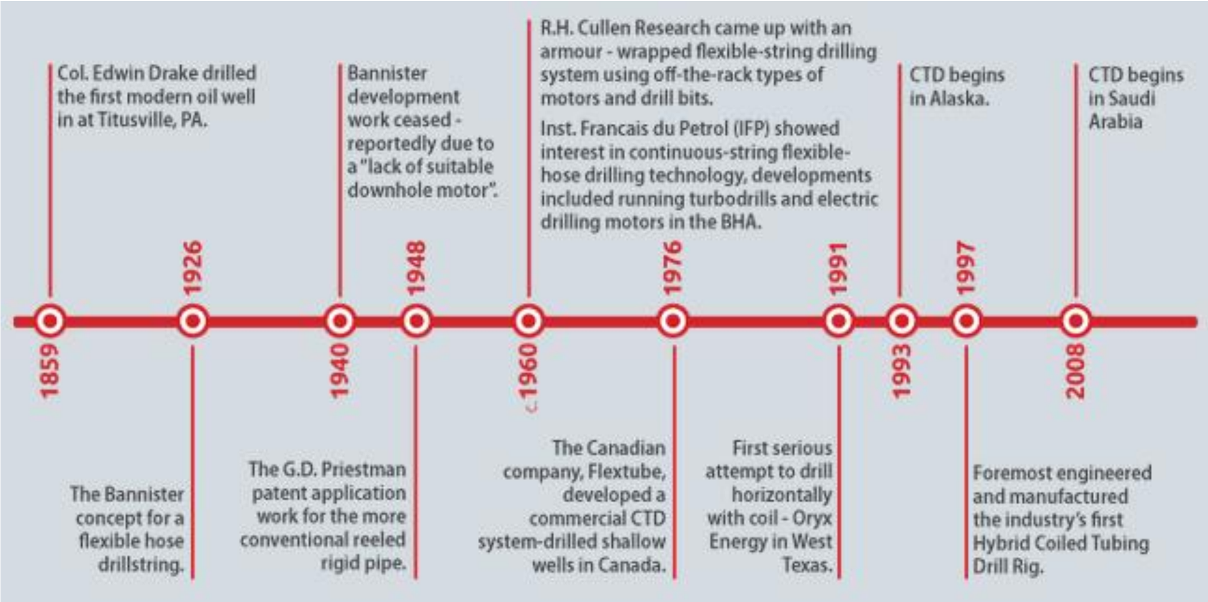


Figure 2-10 History of CTD (AnTech 2015)

CTD history is shown in Figure 2-10. It shows that from FlexTube's project in Canada in 1976 to the beginning of the 1990's there wasn't much activity in the CTD market. In 1991 the interest in the technology again increased. New CTD projects were started in France and Texas and they sat the standard for the new era in CTD. From the early 90's and up to date, thousands of wells have been constructed with CTD and new applications and technology have been introduced. CTD is today the preferred penetration method on the Alaskan North Slope. CTD has been used with success all around the world.

2.3.2. Drilling Applications

CTD operations have proved to be technical and commercial successful in various operations to date, these includes (Schlumberger Oilfield Review 2004):

- New wells, especially shallow gas wells and gas-storage projects.
- Through tubing drilling
- Sidetracking
- Horizontal drainage holes
- Operations that is safety-sensitive

- UBO and MPD

CTD advantages when applied in the proper field settings are many, and increasing with continuous technology improvements. Main driving force for implementing CTD is economic benefits and cost savings, other advantages includes (ICOTA 2005):

- Safe and efficient pressure control with constant bottom hole pressures (BHP)
- Fast kick detection and detection of pressure changes downhole
- Faster tripping time
- No stop for connections, continuous operation, penetration and pumping
- Wired BHA with high speed measurement while drilling
- Smaller footprint and weight
- Faster rig-up/rig-down, for land rigs
- Reduced environment impact
- Smaller crew

Faster rig-up and smaller footprint has shown not always to be the case with CTD jobs. Pipe handling equipment is often needed to handle the long BHA's and to run casings, liners and completion. Large diameter CT requires large handling equipment and space. The BOP used in complex operations is large and fluid-handling equipment required to threat and separate the drilling fluid is complex (PetroWiki #2 2015). Purpose built Hybrid CTD rigs, which is equipped with pipe handling equipment and a CTD unit, has been introduced to meet these challenges.

Disadvantages with CTD have to be taken into account when selecting wells for CTD operations. Some of these disadvantages require special focus and detailed planning compared to conventional drilling (PetroWiki #2 2015):

- Inability to rotate the string
- Fatigue lifetime of the coil
- Limited drilling fluid life
- Limited experience
- Reduced pump rates, torque and WOB
- Buckling of the pipe
- More tortuous path
- Hole cleaning challenges
- Cost of special equipment

- Unexperienced crew

CTD can be divided into directional and non-directional wells. In both methods, downhole mud motors is used to rotate the bit. CTD can be used to drill overbalanced and underbalanced. The closed, continuous circulating fluid system makes CTD a very good candidate for UBO and MPD.

Non-directional wells

Non-directional wells is drilled fairly as conventional rotary drilling, with drill collars to increase WOB and to control angle build up in low angle wells. These non-directional wells are used for instance in Canada to drill shallow gas wells, and represents the largest CTD application to date. Hole sizes up to 13 ¾” have been drilled, but the CTD concept is mostly used to make smaller than 7” holes. These operations are fast to rig-up/rig-down and the continuous rate of penetration (ROP) leads to fast drilling of small diameter wells (ICOTA 2005).

Directional wells

Directional wells drilled with CTD uses a steerable BHA with a rotating steerable system (RSS) or a bent sub, to be able to steer the bit to drill in the desired direction. Since the CT does not rotate, an orienting device is needed to control the well trajectory (ICOTA 2005). Special, small hole, RSS are custom made for CTD operations.

Figure 2-11 illustrates a directional CTD setup. A 2” CT is connected to the BHA. The BHA consists of an orienting sub, a bent sub and a mud motor to be able to drill directional wells. The wireline inside the CT makes it possible to communicate with the downhole tools in the BHA. A whipstock is used to kick off from the original wellbore.

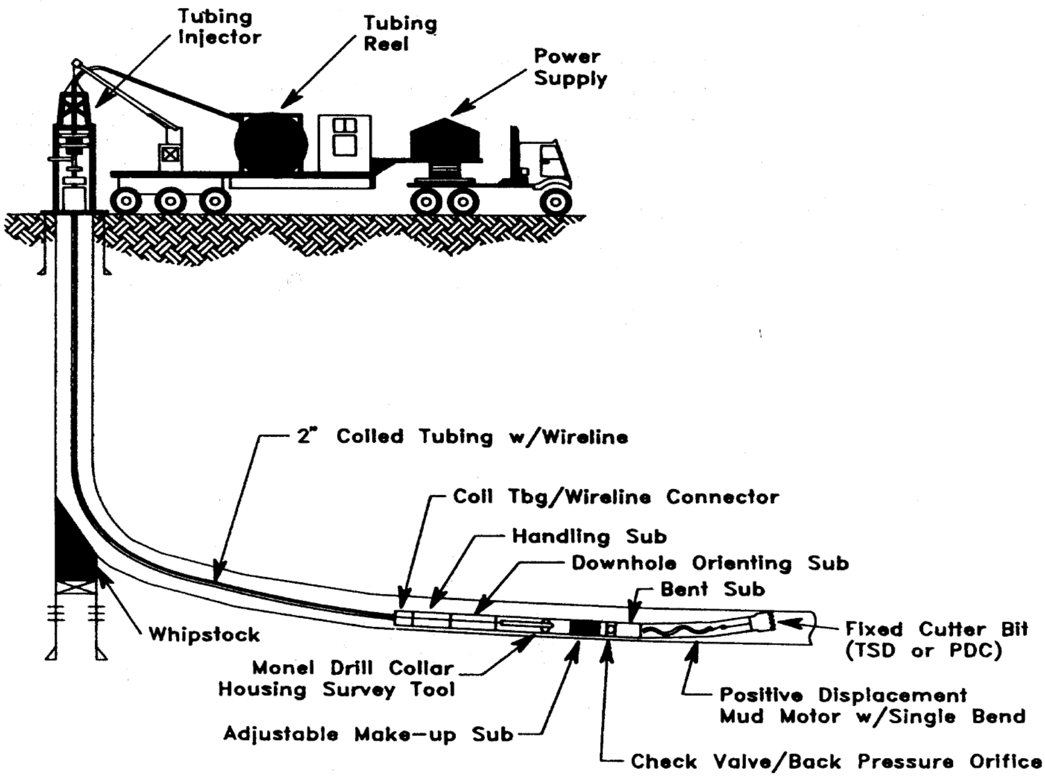


Figure 2-11 CTD setup (University of Stavanger 2010)

2.3.3. CTD BHA

CTD BHA can consist of mud-motor, MWD tools, gyro and RSS for directional drilling or a bent sub, tubing connector, disconnect sub, circulating sub, dual float valve etc. The BHA's are specified and designed for each job and purpose of the CTD operation. Figure 2-12 below is an illustration of a 5" BHA developed to drill larger hole sizes ranging from 6,25" to 8,5". This BHA was designed to drill holes with a motor and bent sub, and therefore the need of an electric orienter and the gyro directional unit. A wireline cable is connected to the BHA inside the CT for downhole communication and power to the BHA.

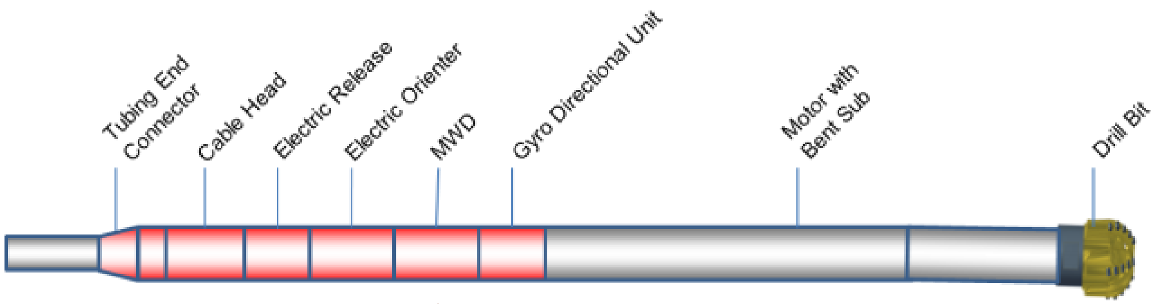


Figure 2-12 Diagram of a 5" BHA (McCuchion, Miszewski og Heaton 2012)

In Figure 2-13 a CTD RSS is illustrated. These RSS are normally small versions of the RSS used in conventional drilling on drill-pipe. These are reliable and well proven systems, and the steering capacity and accuracy is very good. Two different RSS is on the market today, a push-the-bit version that uses pads to push the bit in the desire direction, and a point the bit that points the bit in the desire direction.

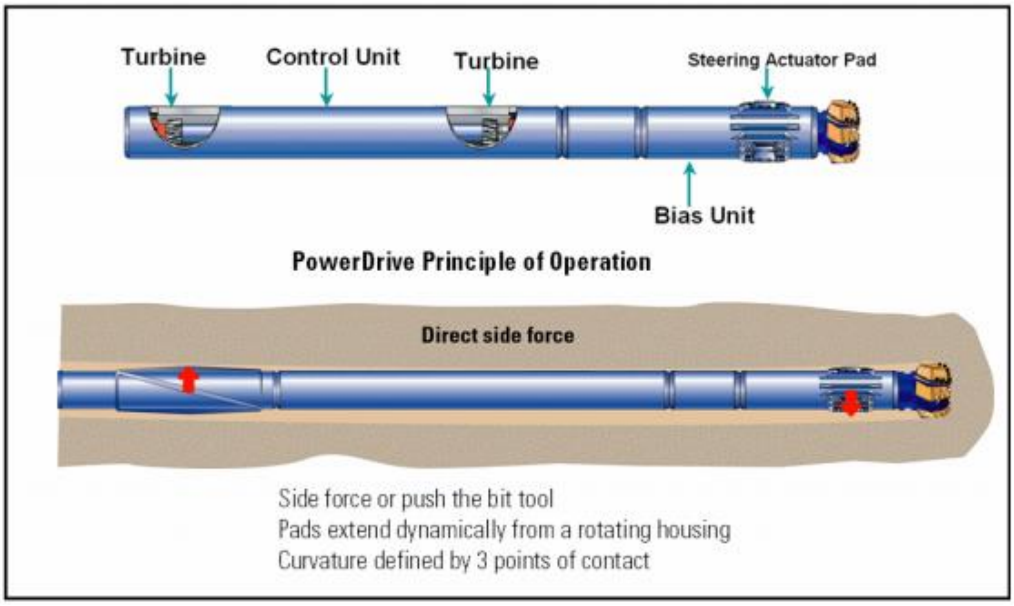


Figure 2-13 RSS/BHA Schematic CTD (Brillon, Shafer og Bello 2007)

CTD mud motors are positive displacement motors that generate rotation of the bit from the hydraulic power from the mud. CT mud motors are available in a wide range of types and sizes from different service companies in the oil industry. The CT mud motors are designed specific for CT and slim hole drilling applications and their applications can include: vertical deepening, milling, de-scaling/de-waxing, windows, cement plugs, balanced and under balanced drilling and directional drilling. Most of the CT mud motors performs well with both WBM and OBM, and also with nitrogen and air drilling fluids.

CTD bit design is usually the same as in conventional drilling. Normal PDC and tri-cone bits can be used, special BI-centered bits and under-reamers can be used in special wells. Bits used in CTD are designed for higher rotation speed, generated by the mud motors, and lower WOB from the lighter and smaller CTD setup.

Downhole communication with the BHA is performed with either a wireline cable inside the CT or through conventional mud pulse communication. The wireline cable can also be used to transfer electrical power to the BHA components. Transmitting data capacity and speed are many times larger for wireline communication than for conventional mud pulse. Mud pulse is transmitting data from and to the surface by generating pressure pulses in the mud. Turbines can be installed in the control unit downhole to generate electrical power in from the circulated fluid.

2.4. Concentric coiled tubing

Concentric coiled tubing (CCT) consist of a CT inside another CT. CCT has been used in well cleaning, well evaluation and stimulation of horizontal wells, and in heavy oil production for thermal insulation in steam injection wells. Well cleaning and Concentric Coiled Tubing Vacuum Technology (CCTVT) is the most used application of CCT today. CCTVT was developed in Canada in the mid 90's for solids removal on onshore heavy oil wells. Today CCTVT has been used worldwide in various applications; cleaning, unloading and complex real time logging of production zones etc.

Figure 2-14 shows the vacuuming BHA and how it works in cleaning operations. Power fluid is pumped down through the inner string and high differential pressure form a vacuuming effect and the fluid flow with solids is dragged into the intake ports and returned to surface in the annulus between the two strings. The annulus area between the strings is small and therefore the fluid velocity becomes very high. Solids transport has shown to be very good even with water as pumped fluid. The CCT used in these applications ranges from the original developed 2,375" (outer string OD) x 1,25" (inner string OD) to today's micro hole CCT with sizes down to 1,5"x0,75".

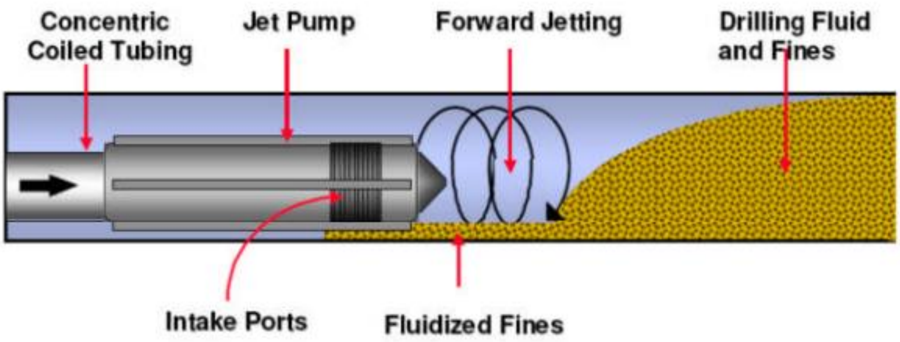


Figure 2-14 Vacuuming Tool in solids removal mode (Pineda, et al. 2013)

Figure 2-15 describes how the CCT is connected to the CT reel. The CT reel is equipped with a double rotary joint. The swivel joint "A" is used for fluid supply and the return fluid is circulated out through the swivel joint "B" (Pineda, et al. 2013). More info on CCTVT operations can be found in a paper by: (Pineda, et al. 2013)

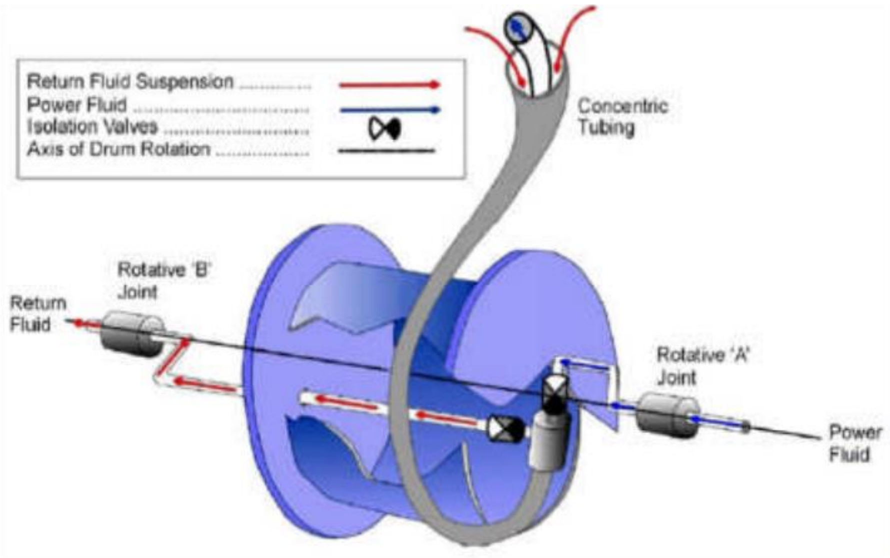


Figure 2-15 CCT working reel (Pineda, et al. 2013)

2.5. Methodology

2.5.1. Well Hydraulics

The term hydraulics is described in the dictionary as the following: *"The scientific study of water and other liquids, in particular their behavior under the influence of mechanical forces and their related uses in engineering* (Dictionary.com u.d.)*."*

It is important to keep in mind the differences in fluid design for CTD applications versus rotary drilling when designing CTD operations. The drilling fluid in CTD is pumped through the entire string regardless of the drilling depth, as it is reeled around the coil if it is not lowered into the hole. Pressure loss in the coiled part of the string is also larger than in the straight section. Small diameter CT strings and high volume flow will give very high pressure loss inside the string. This will set restrictions on the operations. Turbulent flow is often the current flow criteria inside the string as high flow rate is needed in CTD operations. The drilling fluid should behave as low viscosity fluid inside the string to lower the frictional pressure loss and as high viscosity in the annulus fluid to provide cutting lifting capacity. The absence of rotating of the tubing while drilling can be problematic for hole cleaning in deviated and horizontal wells, as rotation in one of the key elements to keep the cuttings suspended. The main components in drilling fluid hydraulics are described in this chapter.

2.5.2. Drilling Fluid

In conventional rotary drilling, drilling fluid is always used. Drilling fluid has several important tasks; the main tasks for the drilling fluid are (Skalle 2013):

- Remove cuttings from the bit. Flushing the cutting from under the bit requires a high flushing effect. This is achieved by inserting small jet nozzles in the rock bit and thereby creating a large pressure drop.
- Transport the cuttings to surface. If this is not done properly, the borehole will get plugged and the drilling operation has to stop. Mud rheology, pump rate and rotating of the drillstring in conventional drilling are the main properties for transport the cuttings to surface.
- Controlling the pump pressure loss in the annulus. Annular friction pressure adds itself onto the hydrostatic wellbore pressure and may create difficult conditions from time to time.
- Maintaining a stable wellbore by providing a sufficient hydrostatic pressure prevents fluid losses from the wellbore and formations fluids from flowing into the wellbore.
- Create a filter cake at the borehole wall to stabilize the formation and prevent fluid invasion.
- Cool and lubricate the bit and the drillstring
- Bring information back to surface
- Provide hydraulic power to downhole tools and mud motors

Drilling fluids used in CTD are either water-based mud (WBM) or oil-based mud (OBM). Air, mist, nitrogen, foam and gas can also be used in special operations. WBM is more environmental friendly and can in some cases be dumped to sea. OBM consist of mostly diesel. This is harmful to marine life and cannot be dumped to sea, it has to be cleaned and transported to shore for treatment. This is an expensive process. WBM do not hold all the good qualities as OBM that is desirable for an efficient drilling process. OBM lubricates better, reduces pipe sticking and hole stabilization problems and it is less likely to cause negative skin effects and reservoir damage.

Drilling fluid is circulated through the wellbore to bring the cuttings to surface. At surface the cuttings get separated out so that clean mud can be re-injected into the well.

2.5.3. Hole Cleaning

"Hole cleaning is the ability of a drilling fluid to transport and suspend drilled cuttings (PetroWiki #3 2015)."

There are several factors that determine the quality of hole cleaning (Eck-Olsen 2014):"

- Rotary speed
- Flow rate
- Mud rheology
- Hole size
- Washouts
- Drill pipe diameter
- Wellbore angle
- Turbulent or laminar flow
- Cutting size
- Mud weight
- Pipe reciprocation
- % sliding
- Penetration rate
- Wellbore stability
- Mud solids (colloidal)
- Cuttings dispersion

The right combination of these factors will help to avoid drilling problems.

The big challenge with hole cleaning in CTD in horizontal wells is the absence of string rotation. No mechanisms can agitate the cuttings from the dunes that are formed when the cutting falls to the low side of the wellbore.

In vertical holes the fluid move upwards, but gravity is pulling downwards, so the cuttings move slightly slower than the fluid.

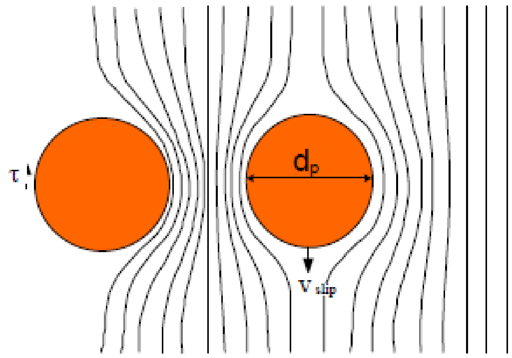


Figure 2-16 Two spheres settling in a vertical well (Skalle 2013)

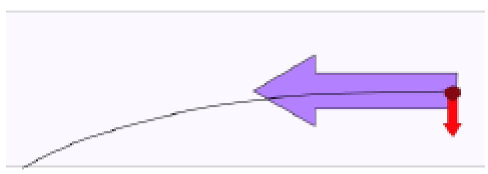


Figure 2-17 Cuttings settling in a horizontal well (Eck-Olsen 2014)

In horizontal holes, the gravity still pulls the cuttings downwards but the flow is now horizontal. There is no longer any fluid velocity direction to combat slip velocity. The settling distance for cuttings in horizontals wells is much shorter and the cuttings fall quickly to the bottom of the well and they start to build beds and dunes, illustrated in Figure 2-1.The cuttings will fall down on the low side, regardless of whether the pumps are on or not (Eck-Olsen 2014).

To be able to transport cuttings out of the hole, the velocity of the fluid flow has to be higher than the slip velocity of the cuttings. Following equations are used to calculate hole cleaning (Skalle 2013):

$$v_{transport} = v_{fluid} - v_{slip} \qquad \textit{Eq. 2-1}$$

Where:

- $v_{transport}$ = Cuttings transport velocity [m/s]
- v_{slip} = Fluid slip velocity [m/s]
- v_{fluid} = Fluid velocity [m/s]

Stokes law can be used to calculate the slip velocity of perfect spheres in laminar flow conditions, however in CT concept in this thesis, turbulent flow will be the flow condition in the circulation system. Following equation is used to calculate the slip velocity for an imperfect sphere. Gravity and shear force will be equal at stationary settling velocity, slip velocity is found with the following equation (Skalle 2013):

$$v_{slip} = \sqrt{\frac{4g(\rho_p - \rho_{mud})d_p}{3C_{drag}\rho_{mud}}} \qquad \textit{Eq. 2-2}$$

Where:

- ρ_p = density cuttings [kg/m^3]
- ρ_{mud} = density mud [kg/m^3]
- C_{drag} = drag coefficient. Turbulent flow: C_{drag} = 0,44. Intermediate flow $C_{drag} = \frac{18}{RE^{0,5}}$

2.5.4. Cuttings Transport

The bit creates rock pieces, called cuttings, while grinding and cutting the rock when it rotates with sufficient rotations per minute (RPM) and WOB. Cuttings are constantly created under the drilling process. The rate of cuttings produced while drilling is (Skalle 2013):

$$q_{cuttings} = \frac{\pi}{4} * d_{bit}^2 * ROP \qquad \text{Eq. 2-3}$$

Where:

- d_{bit} = diameter of the bit [m]
- ROP = rate of penetration [m/hour]

Cuttings concentration (CC) can be estimated by estimating the cuttings volume rate ($q_{cuttings}$) and compare it with the flow-rate. Cuttings concentration is given as:

$$c_{cuttings} = \frac{q_{cuttings}}{q_{flow\ rate\ fluid}} \qquad \text{Eq. 2-4}$$

Where:

- $c_{cuttings}$ = CC [%]
- $q_{cuttings}$ = cuttings volume rate at given ROP and bit diameter [m^3/h]
- $q_{flow\ rate\ fluid}$ = flow rate drilling fluid [m^3/h]

Based on statistics, major hole problems starts to occur when cuttings concentration are above 4% (Skalle 2013).

2.5.5. Equivalent Circulating Density

In a well drilling process, the mud weight has to stay within the pore- and fracture pressure for the given section, this is determined from Eq. 2-5.

$$Mudweight = \frac{P}{g * h} \qquad \text{Eq. 2-5}$$

Where:

- P = Downhole pressure [Pa]
- g = 9,81 [m/s^2]
- h = True Vertical Depth [m]

Equivalent Circulation Density (ECD) is "the effective density exerted by circulating fluid against the formation that takes into account the pressure drop in the annulus above the point being considered (Schlumberger Glossary u.d.)."

$$ECD = \frac{P_{mud} + \Delta P}{g * TVD} \qquad \textit{Eq. 2-6}$$

Where:

- P_{mud} = Static pressure from the mud [Pa]
- ΔP = Difference in pressure, due to friction when circulation [Pa]
- TVD = True Vertical Depth, mud level to lowest point in the well [m]

"The ECD is an important parameter in avoiding kicks and losses, particularly in wells that have a narrow window between the fracture and pore-pressure gradient (Schlumberger Glossary u.d.)". The ECD will increase the downhole pressure in the well. A dynamic mud gradient will represents the ECD. The Bottom Hole Pressure (BHP) will increase when mud is circulated due to the pressure drop caused by friction.

2.5.6. Hydraulic Pressure Loss in the CT Circulating System

The pressure loss in the dual CT circulating system is the sum of the pressure loss over all the components in the circulating system:

$$\begin{aligned}\Delta P_{total} = \Delta P_{surface} + \Delta P_{CT\,reel} + \Delta P_{CTsupply} + \Delta P_{BHA} + \Delta P_{motor} \\ + \Delta P_{bit} + \Delta P_{open\,hole} + \Delta P_{CTreturn} + \Delta P_{CT\,reel}\end{aligned} \qquad \textit{Eq. 2-7}$$

The following section is modified from equations taken from papers by (Guan, et al. 2014) and (Dongjun, et al. 2012) to fit the dual string CT model. In these two studies, theoretical calculations are compared with field experiments.

Flow paths for the concentric dual CT strings are illustrated in Figure 2-18 below. Supply fluid flows in the annulus between the two strings and return flow is through the inner pipe, or the other way around.

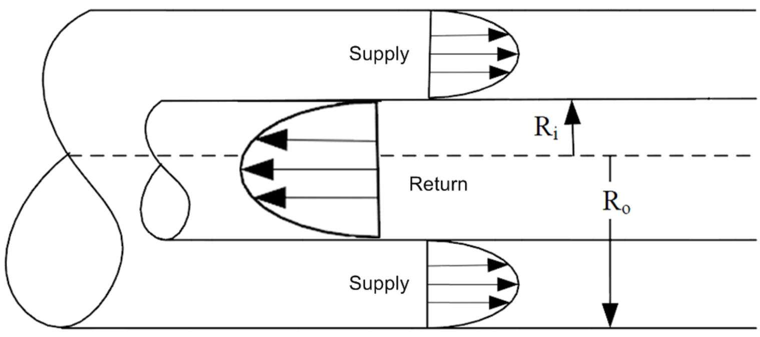


Figure 2-18 Fluid flow in dual CT

Water is used as drilling fluid in the calculations in this thesis. Following assumptions is made for the calculations:

- Drilling fluid is Newtonian fluid
- Drilling fluid in each part of the circulation system is turbulent flow
- Drilling fluid is incompressible
- The inner CT is concentric in the outer CT

The equations for pressure loss calculation in inner pipe flow and in annular pipe flow are given as follows:

For inner pipe flow, return fluid:

$$\Delta P_i = \frac{2fL\rho v^2}{d_{i1}}$$ *Eq. 2-8*

For annular pipe flow, supply fluid:

$$\Delta P_a = \frac{2fL\rho v^2}{d_{i2} - d_{o1}}$$ *Eq. 2-9*

Where:

- L = Length of the CT [m]
- v_{fluid} = average velocity of fluid [m/s]
- f = fanning friction factor
- $\rho, drilling\ fluid$ = fluid density [kg/m^3]
- d_{i1} = Inner CT inner diameter [m]
- d_{i2} = Outer CT inner diameter [m]
- d_{o1} = Inner CT outer diameter [m]

Fanning friction factors for different part of the CT circulation system is calculated as following:

Straight part of the CT system:

Smooth pipes:

$$f_{SCL} = \frac{0{,}0791}{N_{re}^{0{,}25}}$$ *Eq. 2-10*

For rough pipes:

$$\frac{1}{\sqrt{f_{SL}}} = -4\log\left[\frac{\varphi}{3{,}7d} + \frac{1{,}255}{N_{re}\sqrt{f_{SL}}}\right] \qquad \textit{Eq. 2-11}$$

Where:

- φ = absolute roughness of the CT, approximately 0,04725 mm for steel pipes.
- N_{re} = Reynolds number,
- d = inner diameter of the CT [m].

For the coiled part of the CT, the Sas-Jaworsky correlation (Guan, et al. 2014) gives:

$$f_{CL} = f_{sl} + 0{,}0075\sqrt{CR} \qquad \textit{Eq. 2-12}$$

Another proposed equation from (Dongjun, et al. 2012) for coiled part of CT is:

$$f_{CL} = \frac{0{,}841}{N_{re}^{0,2}} CR^{0,1} \qquad \textit{Eq. 2-13}$$

$$CR = \frac{r_0}{R} \qquad \textit{Eq. 2-14}$$

Where:

- r_0= radius of the CT
- R = Radius of CT reel

The range of CR for 2 7/8" used in the industry is from 0,01 to 0,03

Annular flow in the CT in the vertical section is given by an approximate equation from (Dongjun, et al. 2012):

$$f_{An} = \frac{0{,}059}{N_{re}^{0,2}} \qquad \textit{Eq. 2-15}$$

Annular flow in open hole over the BHA

$$f_{An} = \frac{1}{4}\left[\ln\left[\frac{\Delta}{3{,}715(OH - d_{BHA})} + \frac{6{,}943^{0,9}}{N_{re}}\right]\right]^{-2} \qquad \textit{Eq. 2-16}$$

Where:

- Δ = Roughness of the open hole. [mm]
- OH= Diameter open hole [m]
- d_{BHA} = Diameter BHA [m]

Reynolds number for Newtonian fluids is calculated as following for pipe flow:

$$N_{RE} = \frac{\rho v d}{PV} \qquad Eq. 2\text{-}17$$

Reynolds number for annulus flow:

$$N_{RE} = \frac{\rho v (d_{i2} - d_{o1})}{PV} \qquad Eq. 2\text{-}18$$

Where PV is the fluid dynamic viscosity of the fluid.

A paper by (Subhash og Zhou 2001) discussed the effect of drilling solids on frictional pressure loss in CTD. A full scale test facility was used to conduct the study. The study shows that frictional pressure losses increased significantly with higher solid concentration. However, the effect of lubricants in the fluid could effectively reduce frictional pressure loss in CT (Subhash og Zhou 2001).

2.5.7. Buoyancy

Buoyancy needs to be added to the weight of the string in air to get the correct submerged weight. Buoyancy for a single pipe is calculated as follows:

$$\beta = \frac{Suspended\ weight\ in\ mud}{Weight\ in\ air} = 1 - \frac{\rho_{drilling\ fluid}}{\rho_{steel}} \qquad Eq. 2\text{-}19$$

Where:

- ρ_{steel} = Density of steel, (7850 kg/m^3)
- $\rho_{drilling\ fluid}$ = density of drilling fluid (kg/m^3)

The effective buoyancy for a string system composed of many pipes and different fluids on the inside and outside of the strings is calculated as (Kaarstad og Aadnoy 2011):

$$\beta = 1 - \frac{\sum_{k=1}^{n}(\rho_o r_{o,k}^2 - \rho_i r_{i,k}^2)}{\rho_{pipe} \sum_{k=1}^{n}(r_{o,k}^2 - r_{i,k}^2)} \qquad Eq. 2\text{-}20$$

Where:

- n = Number of strings
- ρ_o= Density outside fluid [kg/m3]
- ρ_i = Density inside fluid [kg/m3]
- r_o = Outside radius pipe [m]
- r_i = Inside radius pipe[m]

2.5.8. Axial Load Capacity of CT String

The weight of the CT string and BHA components will stretch the string. This is referred to as axial load or tension. The axial tension will be at maximum when POOH, because of the friction between the string and the borehole. The buoyancy of the string submerged in the drilling fluid will affect the axial load capacity of the string in a positive matter.

Axial load capacity for the CT string is calculated as follows (King 2009):

$$F_y = \sigma_y * A \qquad Eq. 2\text{-}21$$

Where:

- σ_y = Yield strength of the CT [psi]
- A = Cross sectional steel area of the CT [in^2]

2.5.9. Buckling

Helical buckling and the additional wall friction force generated by buckling are assumed to be one of the main limitations with CT. Buckling of a coiled tubing string will occur when a axial compression loads over a critical limit are applied to the string. First the CT will buckle into a sinusoidal wave shape. If the compression force is increased further, the string will subsequently deform into a helix, see Figure 2-19 for illustration. Additional contact force will be developed when the CT forms into a helix as the string will be forced against the confined wall of the wellbore. When helical buckling occurs, the force needed to push the coiled tubing into the wellbore increase greatly. Eventually the string will be in a condition called "lock-up", this is when the frictional drag exponentially increases until it finally overcomes the insertion force. At this point it is not possible to move the string further into the wellbore, or apply more WOB despite addition force applied. (Xiaojun og Kyllingstad 1995)

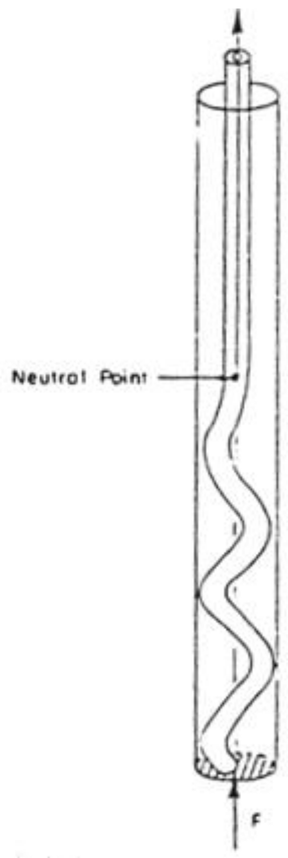


Figure 2-19 CT buckling neutral point in a vertical well (Wu og Juvkam-Wold 1995)

I conventional drilling, heavy weight drill pipe or drill collars are often used above the kick off point in the vertical section to increase the buckling resistance of the string. This is not possible in CTD where a continuous string is used. Buckling in the vertical section in CTD can be a problem when "slacking-off" weight on surface when trying to push the bit in a horizontal section or when applying WOB. The CT can also buckle in the horizontal section where the frictional drag and the required WOB will expose the string to increased compression load (Wu og Juvkam-Wold 1995).

CT buckling calculations is related to the stiffness, E, and Moment of Inertia, I, of the CT string. Moment of Inertia is calculated as follows:

$$I = \frac{\pi}{64}(OD^4 - ID^4) \qquad \textit{Eq. 2-22}$$

Where:

- I = Moment of Inertia [m^4]

- OD = Outer diameter pipe [m]
- ID = Outer diameter pipe[m]

Pipe-in-Pipe CT

Pipe in pipe CT's Moment of inertia is the sum of the Moment of inertia for the strings in the system, calculated for coil-in-coil as following (Yingchun, et al. 2014):

$$I_{total} = I_{inner\ coil} + I_{outer\ coil} \qquad \textit{Eq. 2-23}$$

Pipe in pipe CT's stiffness, E, would be the same as for the single coil if they are made of the same material.

Pipe in pipe unit weight is the sum of the buoyant weight of the two CT strings.

Following equations used in this thesis to calculate buckling are from the paper: Coiled Tubing Buckling Implication in Drilling and Completion Horizontal Wells by (Wu og Juvkam-Wold 1995).

In Horizontal Wellbores:

The CT string will be in compression due to friction force and WOB. The CT will buckle sinusoidal when the compression load exceeds the following criteria (for highly inclined wellbores, including horizontal):

$$F_{sin,inc} = 2\sqrt{\frac{EIW_e \sin\theta}{r}} \qquad \textit{Eq. 2-24}$$

$$r = \frac{OH - OD}{2} \qquad \textit{Eq. 2-25}$$

Where:

- w = Buoyant unit weight of the pipe [N/m]
- E = Youngs modulus for steel = $211*10^9$ [N/m^2]
- I = Moment of Inertia [m^4]
- r = Distance between the CT wall and the borehole wall [m]
- OD = Outer diameter of CT [m]
- OH = Open hole diameter [m]

Helical buckling will occur when the axial compression load increase to the following:

$$F_{hel,inc} = 2(2\sqrt{2}-1)\sqrt{\frac{EIW_e \sin\theta}{r}} \qquad \text{Eq. 2-26}$$

In Vertical Wellbores:

"Slacking off weight" at surface in vertical wellbores to push the CT into the horizontal section or to apply WOB will put the CT bottom string in compression. The CT will buckle when the compressive load exceeds the critical sinusoidal buckling load:

$$F_{sin,vert} = 2{,}55\left(EIW_e{}^2\right)^{\frac{1}{3}} \qquad \text{Eq. 2-27}$$

Helical buckling is predicted to be about 2,2 times as large as the sinusoidal buckling load, derived as:

$$F_{hel,vert} = 5{,}55\left(EIW_e{}^2\right)^{\frac{1}{3}} \qquad \text{Eq. 2-28}$$

The top helical buckling load is the compressive load at the top of the helical buckled portion in vertical wellbores. Is calculated as following:

$$F_{hel,t} = 5{,}55\left(EIW_e{}^2\right)^{\frac{1}{3}} - W_e L_{hel} = 0{,}14\left(EIW_e{}^2\right)^{\frac{1}{3}} \qquad \text{Eq. 2-29}$$

This formula shows that $F_{hel,t}$ will be very close to zero, this proves that the "neutral point" (zero axial load) of the CT will be at the top of the buckling. The neutral point of the string is usually assumed to be at the top of the helical buckling by engineers, without solid mathematic basis (Wu og Juvkam-Wold 1995). See Figure 2-19.

2.5.1. Axial Load Distribution of CT String

Calculation of the axial load distribution is important for the design of CTD operations. Calculation of the maximum transmitted bottom hole force is important to see if enough WOB can be applied to drill the given well section.

Axial load distribution equations for buckled and unbuckled tubulars in different wellbore sections of a well are described in this chapter. Following equations used to calculate the axial load distribution are from the paper: Coiled Tubing Buckling Implication in Drilling and Completion Horizontal Wells by (Wu og Juvkam-Wold 1995).

In Vertical Wellbores

As a function of vertical depth, the transmitted compression load, Fb, max, in vertical wellbores becomes:

$$F_{b,max} = 2\sqrt{\frac{EIW_e}{\mu r}} * \tanh(DW_e\sqrt{\frac{\mu r}{4EIW_e}}) \qquad Eq. 2\text{-}30$$

In Build Wellbores:

The tubular in the build section usually do not buckle, and there will be no additional friction force due to helical buckling (Wu og Juvkam-Wold 1995). The compressive axial load at the kickoff point F_{kop} can be simply related to that at the end of build section F_{eoc} by using these formulas:

$$F_{kop} = \left(F_{eoc} - \frac{W_eR(1-\mu^2)}{1+\mu^2}\right) * e^{\frac{\mu\pi}{2}} + \frac{W_eR(2\mu)}{1+\mu^2} \qquad Eq. 2\text{-}31$$

Where:

- μ = Friction factor borehole wall/casing
- R = radius of curved section [m]

In horizontal wellbores

The axial load will increase linearly along the tubular because of friction drag force if no buckling has occurred (Friction from sinusoidal buckling is not considered because is said to be small):

$$F(X) = F_0 + \mu W_e x \qquad Eq. 2\text{-}32$$

Where:

- x = coordinate along the horizontal axis, measured from the lower end [m]
- F_0 = axial compressive load at the calculation starting point [N]

If helical buckling occurs, the axial load distribution becomes non-linear:

$$F(X) = 2\sqrt{\frac{EIW_e}{r}}\tan(x\mu\sqrt{\frac{rW_e}{4EI}} + \operatorname{arctanh}(F_0\sqrt{\frac{r}{4EIW_e}})) \qquad Eq. 2\text{-}33$$

In vertical wellbores

There is no frictional drag in a vertical wellbore if there is no helical buckling. Axial load varies linearly:

$$F(X) = F_0 - W_e x \qquad \textit{Eq. 2-34}$$

If "slack-off" of the drill string induces helical buckling in the vertical wellbore frictional drag from helical buckling becomes non-linear:

$$F(X) = 2(\sqrt{\frac{EIW_e}{\mu r}} \tanh(-x\sqrt{\frac{\mu r W_e}{4EI}} + \operatorname{arctanh} F_0 \sqrt{\frac{\mu r}{4EIW_e}}) \qquad \textit{Eq. 2-35}$$

3. State of Technology: Dual circulation system

Dual Circulation System (DCS) in petroleum drilling is a concept where two separate fluids are present in the drilling system. The two fluids are separated in a way that makes it possible to circulate the well with one of the fluids, where the other one act as a static fluid column.

3.1. Dual Circulation Systems

Dual circulating system can be divided into three categories:

A) DCS above the mud line (seabed):

This method is also referred to as dual gradient drilling system (DGDS). This was originally developed for drilling in deep waters. Drilling fluid, mud, is pumped down the drill string to the bit and transports cuttings through the annulus back to the seabed. A subsea pump is then connected to the riser and pumps the drilling fluid back to the rig. A lighter fluid can be circulated inside the riser, above the pump and on top of the mud column. This can alternate, or remove the impact of the static head of the drilling fluid in the riser. Drilling can even be performed without a riser if the pump is connected to the system at seabed. See Figure 3-1 and Figure 3-2 below for illustration.

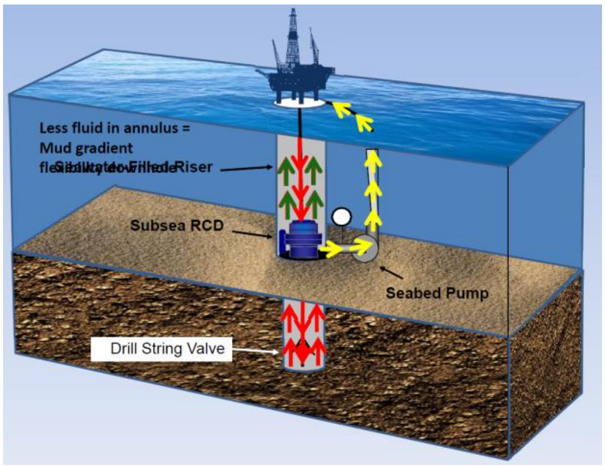


Figure 3-1 Subsea Mudlift Drilling (Eck-Olsen 2014)

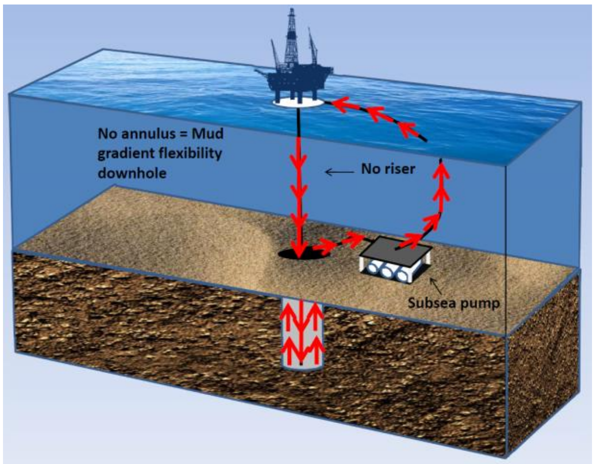


Figure 3-2 Riserless Mud Recovery (Eck-Olsen 2014)

B) DCS below the mud line (seabed):

The concept of this circulating system is to transport the mud back to surface inside a separate conduit. Drilling mud is pumped down through the drill string to the bit as a conventional drilling system, but behind the BHA the drilling fluid is guided into a separate conduit and returned to the rig. A dual drill string can be used for drilling fluid circulation and a static column can be situated in the annulus between the dual drill string and the borehole wall/casing. The two fluids can be separated by an annulus seal, a viscous pill or by gravity in extended reach drilling wells (ERD). This is the concept Reelwell AS tries to commercialize with their RDM method.

C) **Pressurized Mud Cap Drilling (PMCD):**

Pressurized Mud Cap Drilling as defined by the IADC is as follows:

> *"A variation of Managed Pressurized Drilling (MPD), that involves drilling with no returns to surface and where an annulus fluid column, assisted by surface pressure (made possible with the use of an RCD), is maintained above a formation that is capable of accepting fluid and cuttings* (IADC 2015)*".*

Drilling fluid in PMCD drilling is pumped down the string, cleans the bit and is then lost to the formation. A viscous mud cap fluid is situated in the annulus above the loss zone, see Figure 3-3 for illustration.

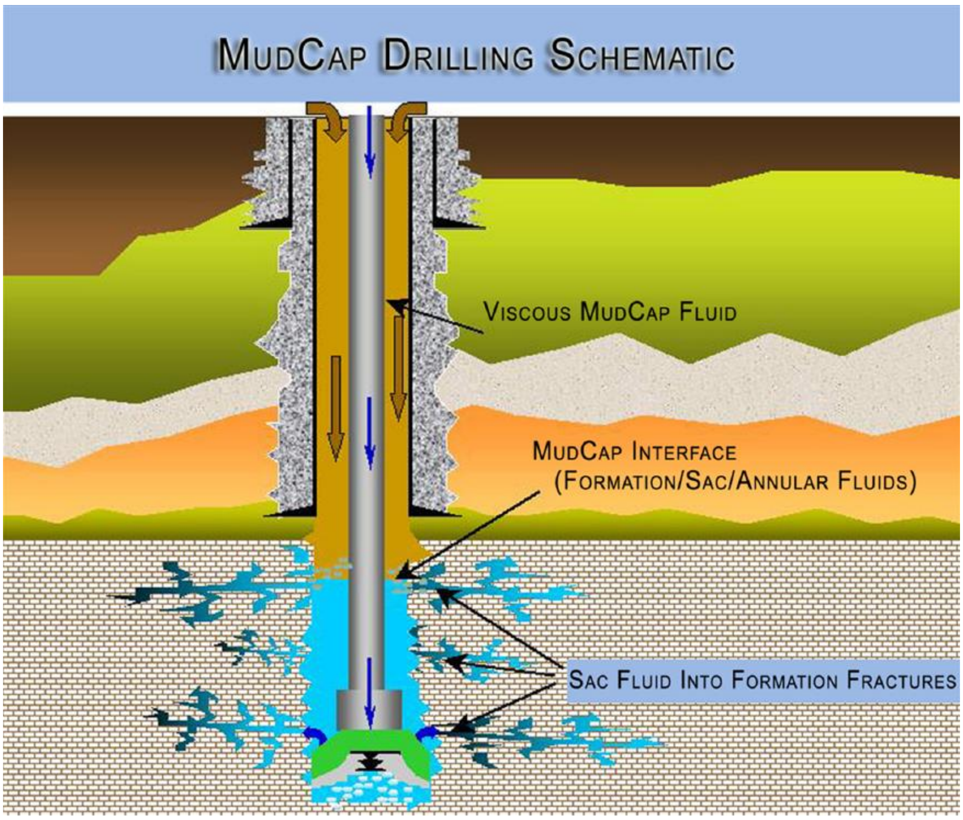


Figure 3-3 Mud Cap Drilling Schematic

In Figure 3-4 below illustrates the advantages with longer sections in DGDS. The white line is the static mud gradient when drilling conventionally. The length of the sections drillable with this gradient is restricted by the pore and fracture pressure and this often make the mud window very small. However, a DGS with two fluid systems allows for controlling the fluid gradient in a better way. In this example the new mud gradient, illustrated with the yellow line, starts from the seafloor and corresponds much better with the underground pressures. The section that is drillable with this system is much longer than with conventional drilling. This will reduce the number of casing points needed to reach the final depth.

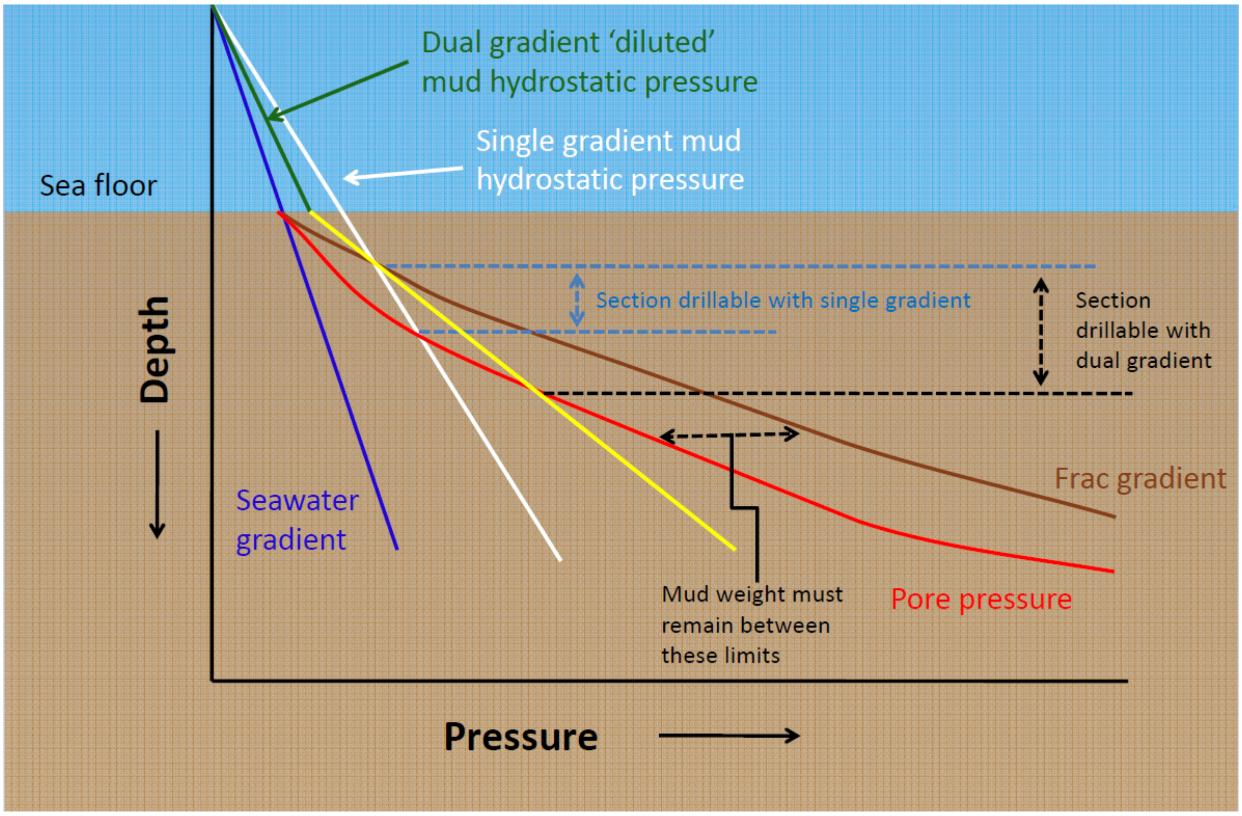


Figure 3-4 Single gradient vs. Dual gradient profile (Eck-Olsen 2014)

The concept of the Coiled tubing drilling system this report evaluates falls under a combination of the B and C category.

3.2. First Dual circulation system

The first know DCS was invented by Homer I. Henderson. His patent from 1965 describes a dual drill string (DDS) drilling method that solved many of the problems that could occur during drilling back in the days. The same problems we want to solve with new technology today.

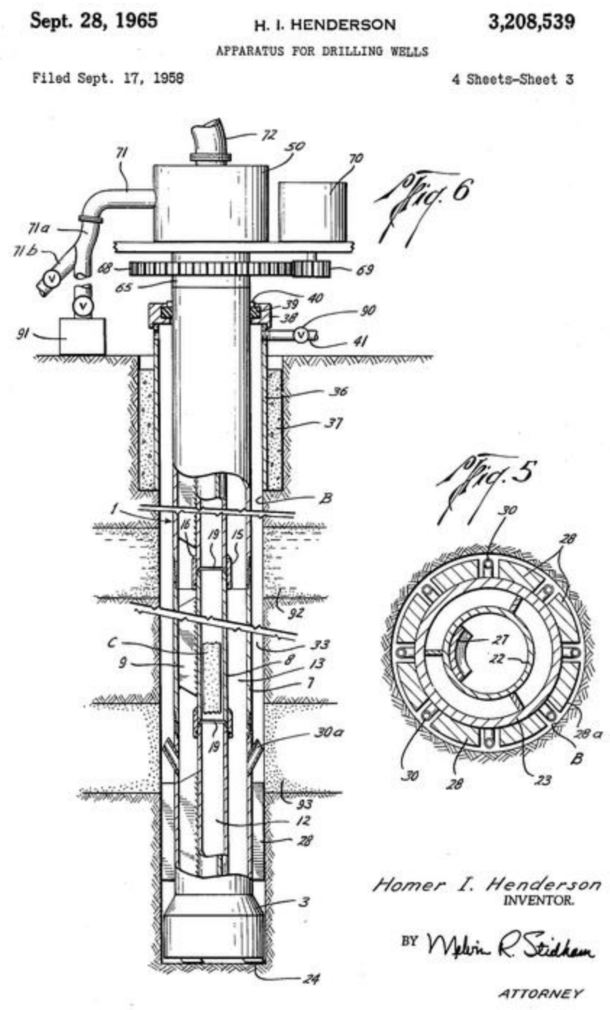


Figure 3-5: Homer I. Henderson's patented dual drill string (Henderson 1965)

The dual circulation system is described in the patent as follows:

> *"While the rotary drilling is being accomplished, a light drilling fluid adapted for efficient removal of cuttings is circulated down through the annulus between the inner and outer pipe and through jets in the drill bit to the bottom of the well and thence up through the inner pipe to the surface. Because an annular drill bit is provided, a core, as well as cuttings, is received within the drill bit and drill pipe as the bit progresses through the formation. When the formation has sufficient strength to hold together, a*

continuous core is formed which moves upwardly through the drill pipe. The core is broken of into short lengths at the bottom of the drill pipe so that the core lengths may be carried upwardly through the drill pipe by the circulating fluid. Thus, the cores when received at the surface can be identified at the depth at which they were taken and analyzed for geological and geophysical data. Also, as part of my method, I provide for the introduction of a specially prepared mud in the annulus between the outer pipe and the well bore to perform other advantageous functions, such as lubrication of the drill pipe, maintenance of a static pressure head on the bore hole, and prevention of the sudden release of gas which might otherwise escape from formations and rise to the surface in a damaging blow-out creating a fire hazard and the like. (Henderson 1965)*"*

As far as the author knows, this method was never tested in the field by Henderson, but it opened for developing of new technology. Today, Reelwell's drilling method is based at the same concept as Henderson developed 50 years ago.

3.3. Reelwell Drilling Method

The Reelwell drilling method (RDM) is a DDS drilling method developed by Reelwell AS, a company located in Stavanger, Norway. Reelwell AS was founded in 2004 with the purpose to develop a DDS drilling method based on research done by Rogaland Research (now IRIS). The purpose of this method is to solve certain drilling problems, improve the operation margin for various applications and to be able to drill challenging wells in a safe, cost efficient and eco-friendly manner. The RDM can be used for PMCD, MPD, ERD and deep water wells. The RDM can be used with regular BHA's, BOP's and conventional drilling rigs.

Advantages with RDM (Reelwell AS u.d.):

- ECD control – Return of drilling fluid and cuttings in separate conduit. Gives near static pressure gradient at all times. Enables drilling through challenging pressure zones with small margins.
- Rapid detection of gain/loss volumes less than 100 l. Improved safety
- Special features for MPD. Downhole well isolation gives constant bottom hole pressure
- Excellent hole cleaning, even with low flow rates.
- Reduce torque, drag and casing wear. Possibility to drill longer.
- Sliding piston can be used to provide hydraulic WOB

- Improved horizontal drilling reach. An aluminum DDP is developed for use in ERD wells.
- Reduce NPT.

All the advantages listed above will in the end save time and money

3.3.1. RDM Setup and Equipment

RDM is a unique drilling method with two flow conduits inside the drill string. A drill string with an inner string is used to form the flow paths. RDM setup is illustrated in Figure 3-6 . Drilling fluid is pumped down through the annulus between the drill strings, illustrated as light blue, and circulated through the BHA and the drill bit. Drilling fluid and cuttings is then guided into the inner string through a dual-float valve behind the BHA and returned to surface through the inner string, illustrated as dark blue. A static fluid column is situated in the well annulus, illustrated with red color. The static fluid column is kept in place by means of a rotating control device installed on top of the BOP (ReelWell AS u.d.).

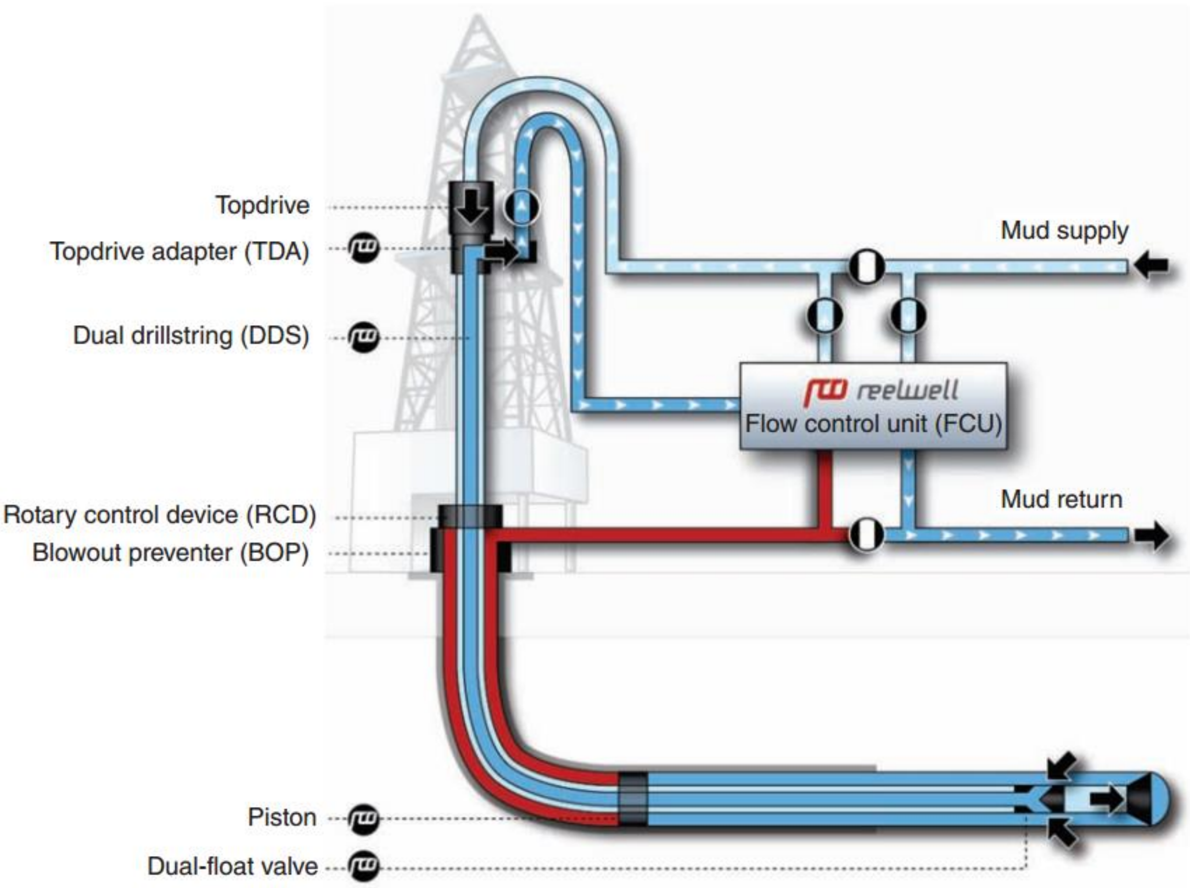


Figure 3-6 Schematic of the equipment arrangement for the RDM (ReelWell AS u.d.)

Figure 3-6 describes the RDM setup. The RDM setup is constructed and adapted to be used with standard drilling rigs and well control equipment, with some adjustments and extra equipment as listed below (Vestavik, et al. 2013):

- Top drive adapter (TDA) - A special swivel connected to the top drive, allow rotation of the DDS and directing the fluid from the inner string to the Reelwell flow control unit.
- Flow control unit (FCU) - Flow and pressure control for supply, return and annulus lines. Installed on a skid and connected to Reelwell's own control panel in the driller's cabin.
- Rotary control device (RCD) - Annulus pressure control device installed on top of the BOP for MPD and to keep the static fluid in place.
- Dual float valve – Flow cross-over directing the return fluid flow with cuttings from the annulus into the inner string and isolating the drill string during connections.
- Piston/Rubber seal - Annulus seal between the two fluid systems. Either placed inside the previous casing or in the newly drilled formation. Can be used as a piston to increase WOB. A heavy over light concept for ERD wells will eliminate the need of a piston.

Reelwell AS has developed two editions of their DDP, one made out steel and one made out of aluminum for use in ERD wells. The DDP is handled and connected in the same way as a conventional drill pipe, no extra equipment or rig crew is needed. The standard configuration is the steel pipe that consists of a 3 ½" concentric inner string installed inside a 6 5/8" drill pipe. The aluminum pipe comes in 5 5/8" to 7 ½" The DDP is rated to 5000 psi and designed to be used with regular BOP's. Field tests have proven that normal shear rams are able to cut the DDP.

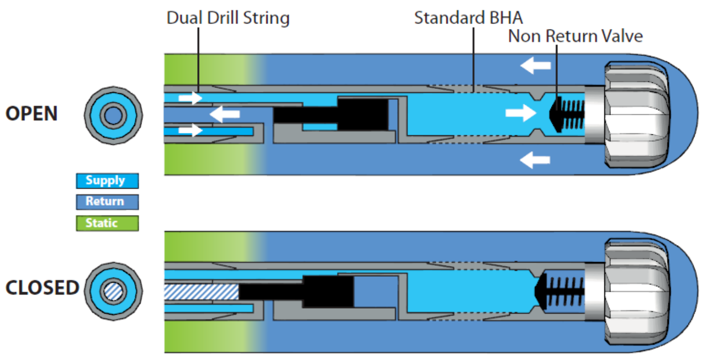


Figure 3-7 Reelwell Inner Pipe Valve (Reelwell AS u.d.)

Figure 3-7 illustrates how Reelwells surface operated downhole isolation valve for DDS works. This valve makes it possible to have pressure free drill pipe connections on the rig floor for MPD operations. In open position, the differential pressure from the supply line keeps the black piston in open position. The drilling fluid is circulated as normal through the BHA and the open non-return valve before it goes through the bit and is circulated back to surface. When the pumps are shut off under connection, the extra differential pressure is no longer present and the black piston will close and seal off the return line. The non-return valve behind the bit will seal off the supply line from the wellbore fluid. This result in constant bottom hole pressure during drilling, pumping, start/stop and tripping.

3.3.2. Hole Cleaning

A dual drill string (DDS) system has some major advantages compared to conventional drilling. Return of the drilling fluid and cuttings inside a smaller diameter drill string makes the bottom-up time very short and lower pump rate is needed to clean the wellbore. In conventional drilling the return fluid goes up through the annulus of the wellbore, the cross section area of this annulus is related to the section being drilled and varies throughout the wellbore. However, it is much larger than the cross section area of the DDS and a tremendous pumping capacity is needed to keep the flow rate high enough for proper hole cleaning.

The RDM offer superior hole cleaning due to cuttings transport in a separated conduit from the bottom of the hole. Hole cleaning in horizontal sections, especially in ERD wells, can be difficult and often create problems with high torque, drag and even stuck pipe. Figure 3-8 illustrates the difference in hole cleaning in conventional drilling compared to the RDM method. In conventional drilling cutting beds will form due to gravity effect on the cuttings. This is not a problem in the RDM when cuttings are circulated back to surface inside the DDS. Simulations and field test has showed successful hole cleaning for the RDM at even low flow rates. Dynamic ECD contribution while drilling is avoided as the ECD effect is screened from the formation and hidden inside the DDS. A static pressure gradient is situated in the well annulus.

Figure 3-8 RDM cuttings transport (Reelwell AS u.d.)

Faster bottoms-up times and no mechanical grinding or mixing of the cuttings makes it possible to do more accurate formation evaluating while drilling. This can reduce the need of well logging, coring and advanced logging while drilling (LWD) tools.

3.3.3. Annular Fluid

The passive annular well fluid is used to control the pressure in the well and stabilize the formation downhole. The active fluid inside the DDP is used to power the BHA, clean the bit and transport cuttings back to surface. Flow rate and chocking of the return at surface can control the downhole well pressure of this fluid.

An annulus sealing mechanism, or a gravity dependent solution, is proposed to be used in the RDM to keep the two fluid systems separated. It should also hinder the drilling fluid from going up the outer annulus instead of into the DDP. This seal must be attached to the DDP and follow the axial string movement. Various sealing concept can be used: Over-gauge rubber seal, piston in the previous casing or in the open hole, or a heavy over light concept in ERD wells. The over-gauge rubber seal is a downhole inflatable packer. For this packer to seal properly the wellbore diameter needs to be stable. This is not always the case in open hole and this concept is not a preferred method, but has shown its reliability in field tests. The packer has to slide along the wellbore in inflated position with the movement of the DDP and this will put a lot of wear on the packer from the formation.

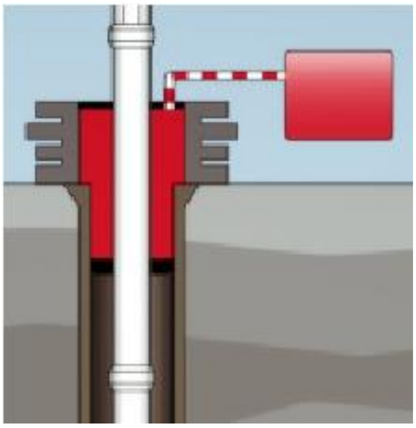


Figure 3-9 WOB increase by use of piston (Reelwell AS u.d.)

Figure 3-9 shows how a piston can be installed as the annulus seal and in the same way be used to increase WOB. Drilling fluid is circulated as normal in the RDM method, inside the DDP, and pressure from surface can be applied to the annulus fluid (indicated as red in the picture) in the outer annulus. This will push on the piston (indicated as black in the figure) that is attached to the drill string. The piston can be installed inside the previous casing or, if the formation can withstand the increased pressure, be installed in the open hole.

3.3.4. Heavy over Light Concept

The heavy over light concept is illustrated in Figure 3-10. This concept was developed to look into the possibility to drill very long ERD wells with the RDM. A joint industrial project called “ERD beyond 20km” was started in 2011 and is described in the paper: Extended Reach Drilling – new solution with a unique potential (Vestavik, et al. 2013). This feasibility study uses the RDM in a heavy over light project with the aluminum DDP. The lighter density drilling fluid, showed as blue in Figure 3-10, will float and be trapped on top of a heavy density annulus fluid and the need of a physical seal is eliminated. An optional piston arrangement can be used to increase WOB by hydraulic pressure of the annulus fluid. The well trajectory has to be special designed to this purpose, with a fluid trap formed by an increasing inclination from the heel to the toe in the well. The aluminum pipe with a light drilling fluid will float on the heavier annulus fluid, this ensures low, or even eliminates, torque and drag effects. This is due to the reduced friction effect between the drill string and the hole with the buoyant DDS. Reelwell has planned to test the ERD capability of the RDM on an onshore ERD well in Texas in 2015.

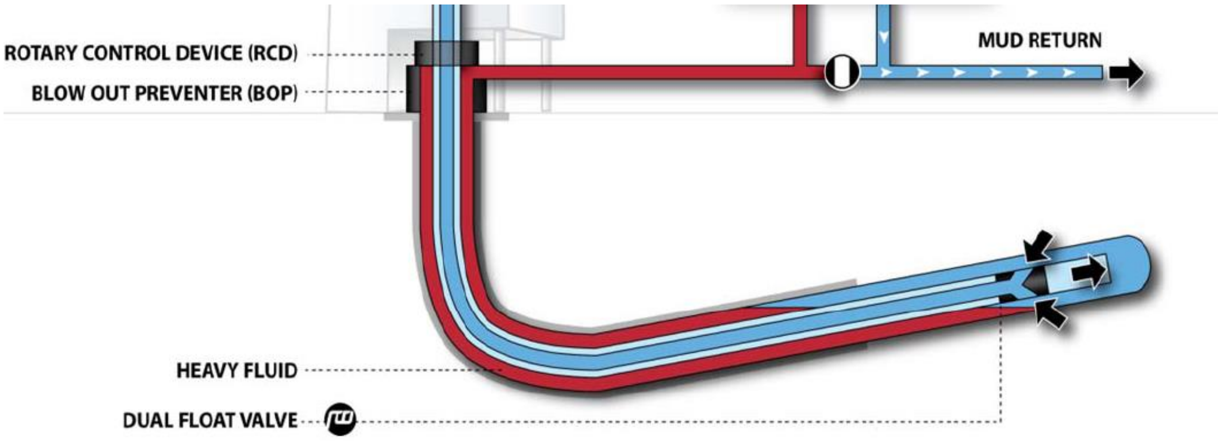


Figure 3-10 Heavy over light (Vestavik, et al. 2013)

3.3.1. Field Tests

The RDM has shown promising results from field tests at Ullrigg in Stavanger, in an onshore shallow gas well In Canada and in an onshore well in the Middle East. In December 2015 the RDM was used to drill a 12 ¼" section through a loss circulating zone in Saudi Arabia. The operation was successful and showed the potential of the RDM with PMCD with advantages as; efficient hole cleaning at low flow rates, constant bottom hole pressure, minimum fluid loss, compatibility with an RSS and a conventional MWD system etc. A leakage in the inner pipe ended the operation, but all the other equipment and arrangements proved their reliability. The pipe is being upgraded and the next step for the RDM is to prove its features in an ERD well in Texas, hopefully in 2015 (Alexandersen og Vestavik 2015).

3.4. Riser-Less Drilling with Casing (3LD) Concept

A riser-less drilling with casing concept using a dual gradient mud system is developed by Sigbjørn Sangesland at NTNU and Geir Tandberg and Jøren Breda at FMC Kongsberg Subsea. It was presented in 2001 at the Eleventh International Offshore and Polar Engineering Conference. The objective of this concept is:

- Drill cheaper deep-water wells with a slender well program, using a minimum number of casing strings. This reduces tripping time and money spent on consumables (mud, casing etc.)
- Casing while drilling (CWD) reduces time consumption.
- Cementing before tripping reduces time consumption further.
- Avoid handling the large and heavy 21" marine drilling riser in deep water wells.

- As well as compensating for small pressure margins between pore and fracture pressure in deep-water wells.

The concept is a combination of many new technologies, including DGDS, CWD and DDS. Simulations conducted in the project show promising cost reduction results for the concept. A reduction in the order of 40-60% compared to conventional drilling is achievable by the use of cheaper rigs, handling of a smaller riser, reduced volume of mud and fewer casing strings, and the cost savings increases with increased water depth. The system, also referred to as Three Line Drilling (3LD), is primarily intended to be used to drill longer top-hole sections. The rest of the sections, including the reservoir section, are to be drilled with more or less conventional drilling methods (Sangesland, Tandberg og Breda 2001).

CWD concept includes casing running while drilling. A bit and the BHA are connected at the end of the casing string in the hole-making process. The bit and the BHA can be retrieved when final depth is reached, or left in the hole and drilled out in the next section. A bi-centered bit or an underreamer is to be used in a retrievable system. The casing is cemented in place right after drilling is finished, this prevents the formation to caving in to the well and it saves time and money. Cementing of the casing in the 3LD system can be done through the barrier fluid (BF) supply line, see Figure 3-11, simultaneously as the borehole is circulated. The inlet of the BF line is located at the bottom of the casing and cement is pumped from bottom and up through the outer annulus above the annulus isolation unit. BF is displaced to sea and therefore has to be environmental friendly. After cementing of the casing annulus, the annulus seal element is deactivated and the BHA is retracted inside the casing and a plug is cemented in the bottom open hole section through the BF line. The hole is now sealed off and the BHA can be pulled. CWD is primarily used to reduce the number of trips.

Figure 3-11 describes the concept of 3LD. The casing, typical a 13 3/8”, is made up and run on drill string. The drillstring is connected in the top and bottom of the casing with running/connection tools. The length of the casing is restricted by the water depth. Drilling fluid supply and return, and barrier fluid supply are connected to a valve manifold connected at the bottom of the casing above the Casing/BHA connection tool. Cables for power supply, control and monitoring are also guided down inside the casing. The BHA consist of a drillbit, underreamer, expandable stabilizer, mud motor, directional control unit, online measuring unit, drill fluid return inlet valve, expandable packer and a casing connection tool.

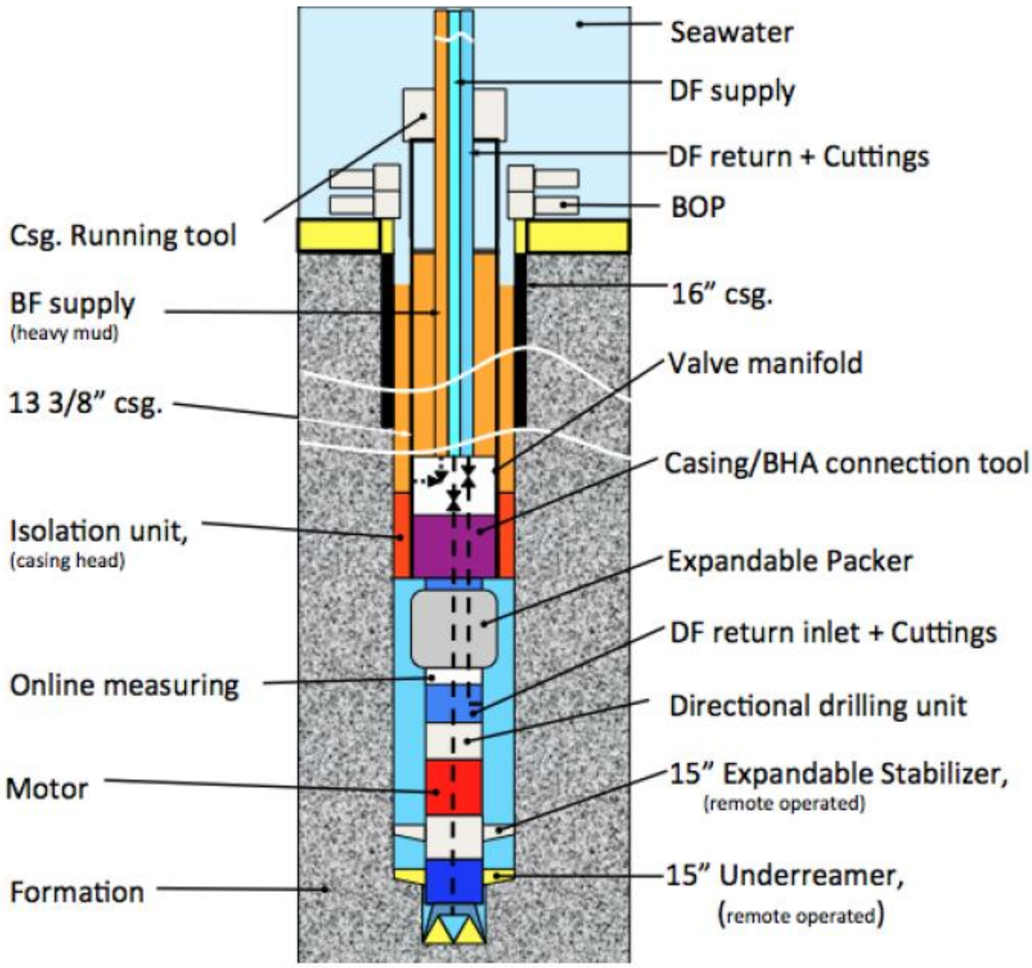


Figure 3-11 Principal sketch of the 3LD system (Sangesland, Tandberg og Breda 2001)

3.4.1. The Dual Gradient Drilling Method in 3LD

A dual gradient drilling system eliminates the use of a large and heavy marine drilling riser. Light drilling fluid with additives is circulated through separate flow conduits. A heavy BF is situated in the annulus between the casing and the open hole/previous casing to control the open hole above the isolating unit. The drilling fluid will be a low-density fluid that is optimized with additives for proper hole cleaning and it will only be in contact with the formation in a short distance and time below the isolating unit. BF is added through the BF supply line during drilling to maintain the wanted downhole pressure. See Figure 3-12 for graphical illustration of the DGDM of the 3LD system. The two fluid systems are separated by an isolating unit. An over-gauge steel mandrel and an inflated element above the BHA can be used. Simulations have showed that the limited length of the isolating unit will not lead to excessive resistance when forcing the casing down (Sangesland, Tandberg og Breda 2001). UBD can be conducted if the sealing between the isolating head and the formation is decent.

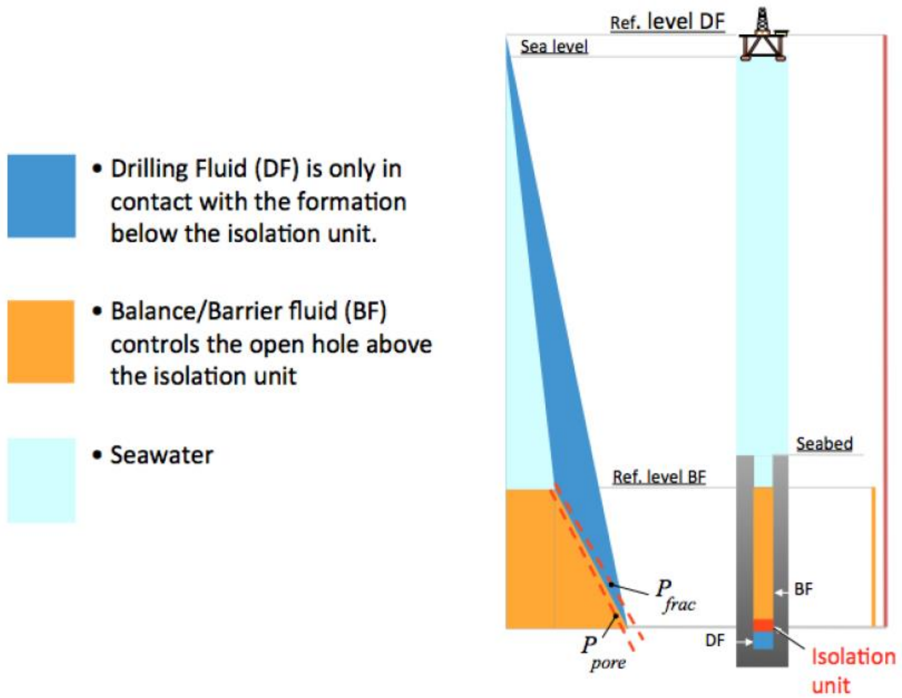


Figure 3-12 Pressure gradients in the 3LD concept (Sangesland, Tandberg og Breda 2001)

"The two fluid interfaces in the annulus below the mud line, allows for increased drilling length thus further reducing the number of casing strings (Sangesland, Tandberg og Breda 2001)". Longer drilling sections is used to design the well as a slender well design. This means that smaller diameter top sections can be used, at the same time as reaching the reservoir with sufficient hole size of the liner. This leads to reduced cost of casings and shorter time spent constructing the well.

The arrangements of the two fluid flow conduits from the BHA to the surface has proven to be a challenge, and different solutions are proposed in the paper; The two flow conduits can be clamped to the drill string and connected to the drilling rig, or they can be implemented in a umbilical handled from the drilling rig or a separate supply vessel with pumping capacity, mud handling and storage facilities.

A choke valve is place inside the drillstring to choke the return fluid and by that controlling the borehole pressure in the lower annulus. The choke can be used to minimize the pressure difference over the isolating unit to tune the drilling fluid pressures.

Significant development work is needed to bring the 3LD concept to a field proven method (Sangesland, Tandberg og Breda 2001).

3.5. Two String Drilling System Using CT

James I. Livingstone US patent nr. 6854534 B2 (Livingstone 2005) from 2005 describes a concentric coiled tubing drilling system with circulation of the drilling fluid inside the dual CT string. This patent covers everything from reciprocation air hammer drilling with a dull bit, a positive displacement motor and a reverse circulating drill bit, or a reverse circulating mud motor and a rotary drill bit. The drilling medium can be circulated down the inner string and back through annulus between the outer and inner string, or the other way around. The drilling medium can be liquid or gas, or a combination of these two.

The concept is shown in Figure 3-13 below. The system is based on a CTD drilling setup, but with a coil-in-coil system and return flow back to surface inside one of the strings instead of through the borehole annulus. The system has not been field tested as far as the author knows.

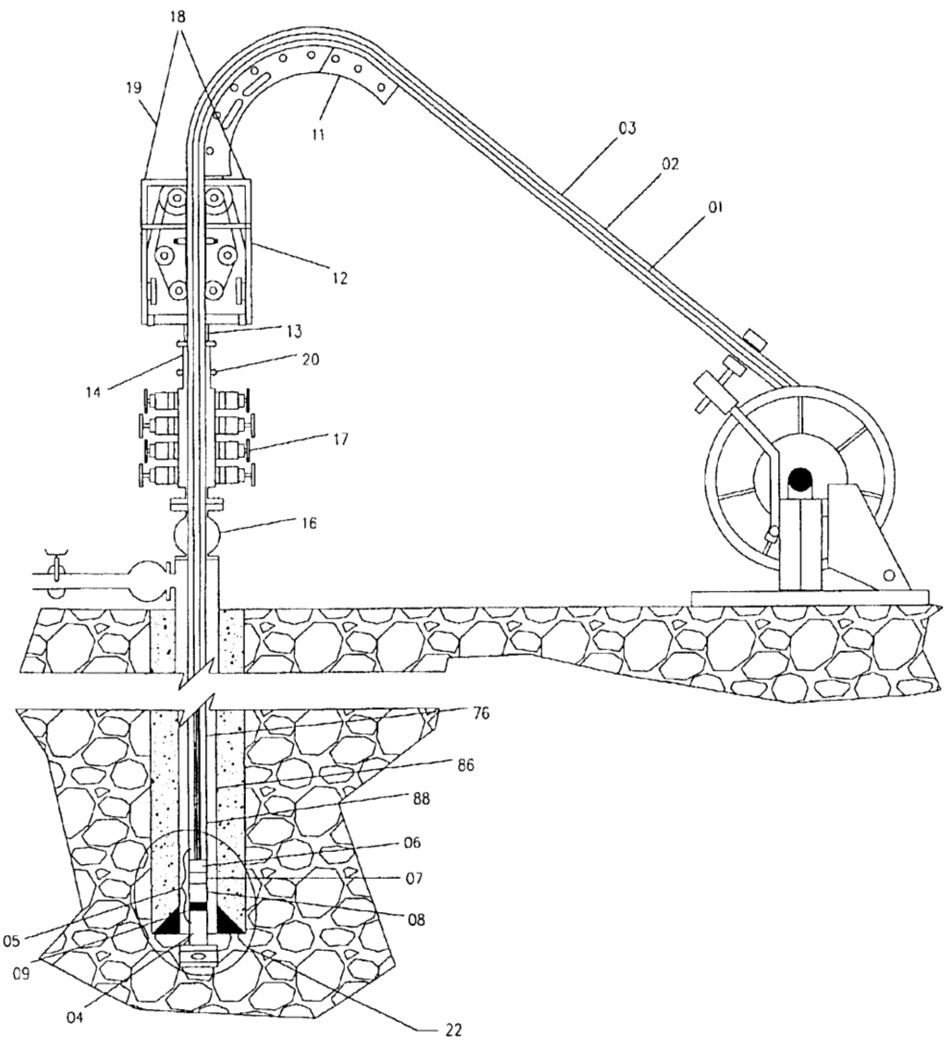


Figure 3-13 James I. LIvingstone Two String drilling system using coil tubing (Livingstone 2005)

3.6. Statoil's CTD Campaign on Heidrun

Statoil recently performed a three well CTD campaign on Heidrun, a floating tension leg platform in the Norwegian Sea. The motivation for this CTD campaign was the need of more drainage holes and to conduct parallel operations with the main rig. A purpose build hybrid, heavy duty CT unit was installed on the platform together with a separated mud system.

A 2 7/8" CT was used to drill 5 7/8" holes through the 7" tubing at 3000 m MD with the use of a whipstock to kick off from the original wellbore. The planned drainage holes extension was roughly 350 meters, with a dog-leg severity of 10°/30 m. The drainage holes were drilled in overbalanced with WBM and mud-pulse telemetry was used for communication with the directional drilling and MWD tools downhole.

Hole cleaning was a problem in this campaign. No cuttings came out during drilling, only when performing frequent wiper trips. Figure 3-14 illustrates how the cuttings build up on the low side of the hole during CTD. Over gauge and under reamed holes in shale was impossible to clean.

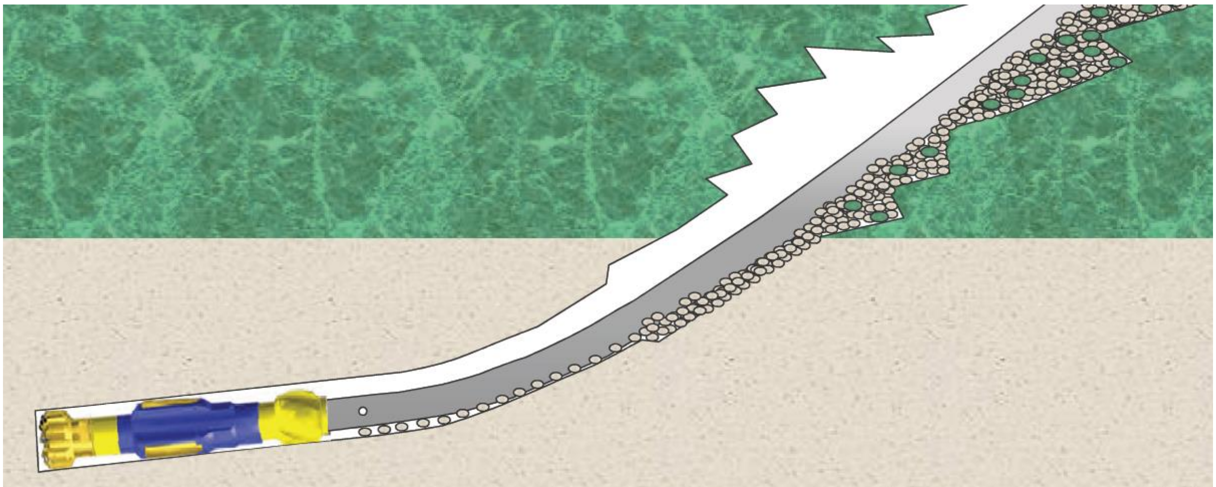


Figure 3-14 Hole cleaning problems CTD on Heidrun (Statoil ASA 2014)

The CT string got differential stuck several times. A nitrogen bubble technique was developed to reduce the BHP pressure to free the string. This worked as intended in the last well.

Primary objective for this CTD campaign was learning. Statoil concluded that the campaign had been a success, even though none of the wells did reach the target. A second campaign will hopefully be initiated in the near future (Statoil ASA 2014).

4. Concept Review and Discussion

The concentric coiled tubing drilling system will be reviewed and discussed in this chapter. The concept is hereafter called DualCTD (Dual Coiled Tubing Drilling).

The DualCTD system is based on the same principle as Reelwell AS's DDS method. The system uses a concentric coil instead of a DDS. J. Livingstone's US patent from 2005 describes a concentric coiled tubing drilling system, discussed briefly in sub section 3.5. His patent covers briefly every aspect and versions of a concentric coiled tubing drilling system for use onshore.

The review of the DualCTD concept in this thesis is on an offshore version of the concentric CT drilling system. It covers every technical aspect of the operation from surface equipment, BHA components, hydraulics, torque & drag and buckling to applications, advantages and limitations.

A feasibility study is developed for the DualCTD concept in the end of this chapter. This study is based on the fundamental requirement for any CTD operation. The following condition must be met for the DualCTD operation to be viable:

i) Sufficient WOB must be available from the weight of the CT string, or by pushing the string into the well to achieve an effective ROP.

ii) A sufficient energetic flow regime in the circulation system is required for proper hole cleaning.

iii) Downhole pressure must be low enough to prevent formation damage and the surface pressure in the CT string must be low enough to avoid burst and collapse of the string and to prevent premature CT fatigue.

iv) Logistical constraints such as crane-, reel- and deck loading capacity.

4.1. Drivers for introducing the DualCTD concept

- The need of more drainage holes to increase recovery
- Drilling into or through mature and depleted zones with narrow pressure windows
- Solve hole cleaning issues with CTD in horizontal wells with low flow rates
- Use of a drilling fluid that is optimized for hole cleaning capabilities and a secondary fluid to give hydrostatic head and to stabilize the formation
- Buoyant dual string system to compensate for buckling and increased frictional drag in horizontal sections

- Lower circulating volumes
- Use smaller and cheaper rigs/intervention ships to perform drilling operations

4.2. Concept Review

The main intention for the DualCTD concept is to drill subsea wells from a floating vessel. Two case studies for the DualCTD concept are conducted in chapter 5 on drainage hole drilling and production drilling.

The DualCTD system is illustrated in Figure 4-1 for drilling of a horizontal well. A dual CT string is run from the rig and injected into the well with a subsea CT injector at the seafloor. A control head and a BOP are located at the seafloor for well control purposes. The dual CT string and the BHA with a mud motor and bit is then run to the bottom of the well to start the drilling operation.

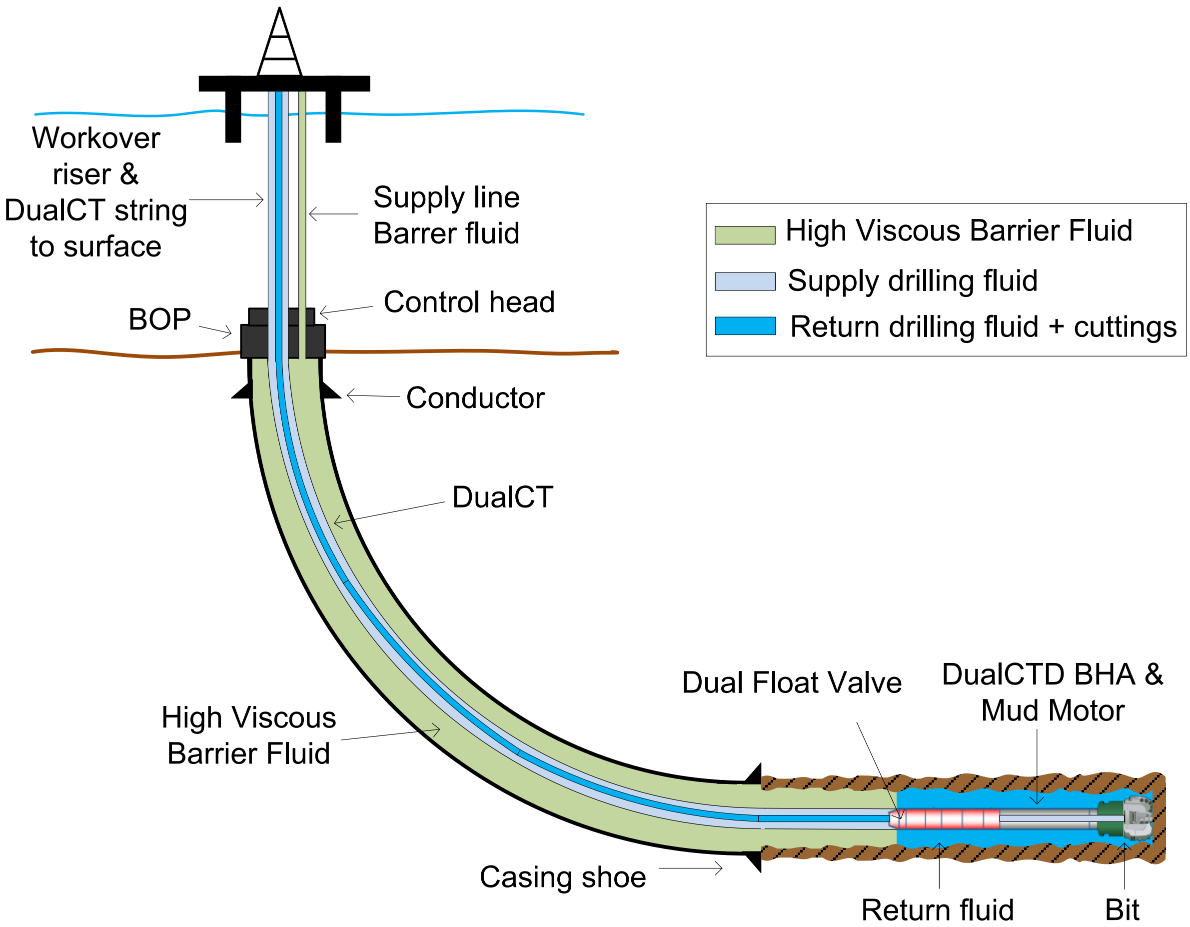


Figure 4-1 DualCTD horizontal drilling illustration

The fluid flow arrangement in the BHA is illustrated in Figure 4-2.

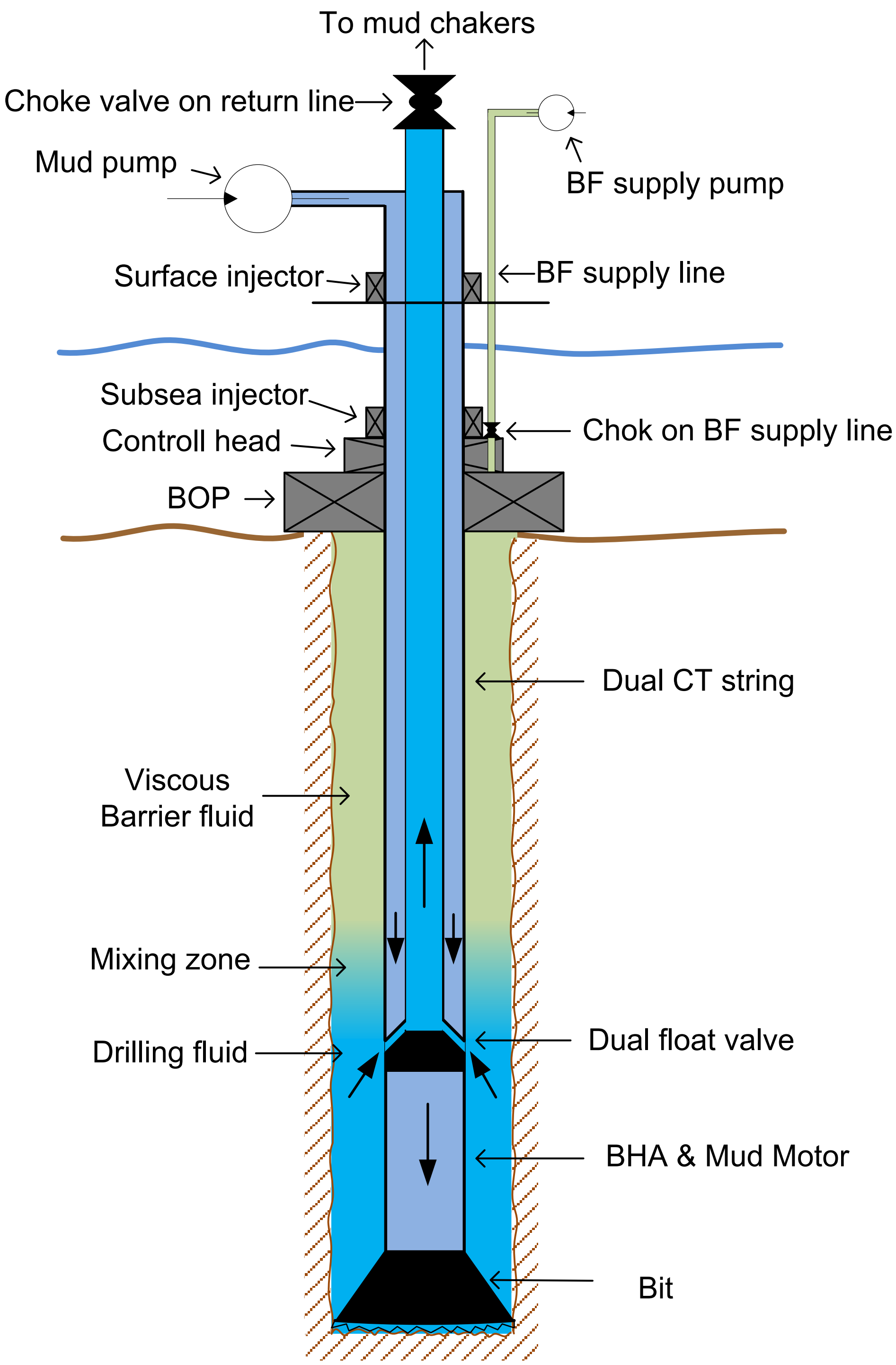


Figure 4-2 DualCTD BHA flow arrangement

Light blue is supply fluid, dark blue is return fluid and green is the barrier fluid (BF) in the secondary annulus

Supply drilling fluid is circulated through the annulus of the dual CT string down to the DualCTD BHA where a dual float valve (DFV) guides the fluid to the BHA, mud motor and bit. The mud motor uses the hydraulic power from the drilling fluid to rotate the bit. Drilling fluid then cleans the bit and transports the cuttings to the end of the BHA, where ports in the DFV guides the drilling fluid with cuttings into the inner string where it is transported back to the rig. Return of the drilling fluid with cuttings in the annulus between the two CT strings can cause problems with cuttings getting stuck and blocking the flow path because of the small annular clearance between the two pipes. The inner string will not be centered in the outer string and therefore lay on the low side of the wellbore.

Surface and subsea equipment arrangement for the DualCTD system are also illustrated in Figure 4-2. The DualCTD surface arrangement will look more likely as the surface equipment in J. Livingston's patent for an onshore system, illustrated in Figure 3-13. A heavy duty CT unit special designed for the concept is needed together with a large well intervention tower. The main components needed to perform DualCTD subsea from a floater are as follows:

- Subsea BOP
- Subsea heavy duty Injector to push and pull the dual CT string in/out of the well
- Surface Injector to hoist the CT string and to keep the CT string in tension.
- Large lubricator to be able to run the long DualCTD BHA into a live well with wellhead pressure.
- Gooseneck to guide the string from the reel into the stripper at the rig floor.
- CT reel for a dual CT string with supply and return outlets
- Supply line for barrier fluid with a choke valve on the seafloor
- Pressure control equipment, choke on the return line, subsea choke on BF line.
- Two mud systems and separate storage facility for barrier fluid and drilling fluid
- Mud plant (closed system and a separation unit if UB drilling operation is planned)
- Flow control unit to route the fluid flows at surface and to control the downhole pressure automatically.

If the DualCTD system is run with a workover riser following extra equipment is needed:

- Work over riser tensioner.
- Lubricator at the rig floor
- Well control equipment/ secondary BOP connected at top of the riser

4.3. Fluid System in the DualCTD Concept

One of the advantages with the DualCTD concept is the continuous circulating of drilling fluid through the CT string. There are no connections in CTD, as in conventional jointed-pipe operations. This leads to no interruption of circulation. Continuous circulation and pumping gives a constant and predictable frictional pressure drop in the circulating system. This makes it easy to compensate for the ECD effect downhole. The ECD effect is the extra corresponding downhole fluid density for the frictional pressure loss in the circulating system felt by the formation. ECD in described in sub section 2.5.5.

The annulus that is formed between the DualCTD string and the borehole wall/casing will be a passive annulus that is not a part of the circulating system during drilling. This will be called the secondary annulus.

4.3.1. The Secondary Annulus

The fluid in the secondary annulus is referred to as barrier fluid (BF). The BF in the secondary annulus will not be used for drilling activities, it can therefore be optimized for several important other objectives: The BF needs to secure the borehole wall and eliminate formation damage by limiting fluid invasion and by not reacting with unstable formations. The pressure of the annulus fluid column has to stay within the pore- and fracture pressure of the formation for the whole drilling section.

The BF will be weighted to be able to correspond with the pressure of the formation downhole. As the weighted annulus fluid is not circulated, it has to be able to suspend the weighted particles that are added to the fluid. The mud gradient will no longer be linear if the weight particles settle at the bottom or lower side of the borehole, this can cause instabilities along the borehole wall. Gravity will pull the weight particles downward. A viscous gel like mud type is therefore needed to keep the particles suspended.

Important properties for the annulus fluid are summed up in the following bulletins:

- Maintain a well pressure between the pore- and fracture pressure of the formation
- Friction reducing effect on the CT string
- Suspend the weight material in the static column
- Stabilize the formation by providing a filter cake and not react with unstable formations.

A too thick and viscous annulus fluid can be difficult to circulate in and out of the well prior and after the operation

4.3.2. Use of the Secondary Annulus

A heavier fluid in the secondary annulus together with a light drilling fluid can be used as a way of having buoyancy control. This can be used to drill longer horizontal sections by reducing the frictional drag the CT string. This is discussed more in sub section 4.8..

Narrow pressure windows can be drilled with instant control of the BHP by adjusting the density and height of the BF column. No connection gives constant BHP in the DualCTD concept. The ECD effect will be constant and easy to compensate for at surface with a choke on the return line. A Choke on the BF supply line can also be used to alter the BF gradient to better match the downhole formation pressures. This is illustrated in Figure 3-4.

Excellent hole cleaning makes it possible to drill past lost circulating zones by carefully controlling the annulus pressure. Cuttings will not be in contact with the formation above the inlet ports in the BHA, and by that not damage the formation filter cake.

Figure 4-3 illustrates the fluid gradients in the DualCTD concept. The drilling fluid is compensated with choke on the return line at surface. A choke on the BF supply line alters the gradient of this fluid column to match the seawater gradient at the seafloor.

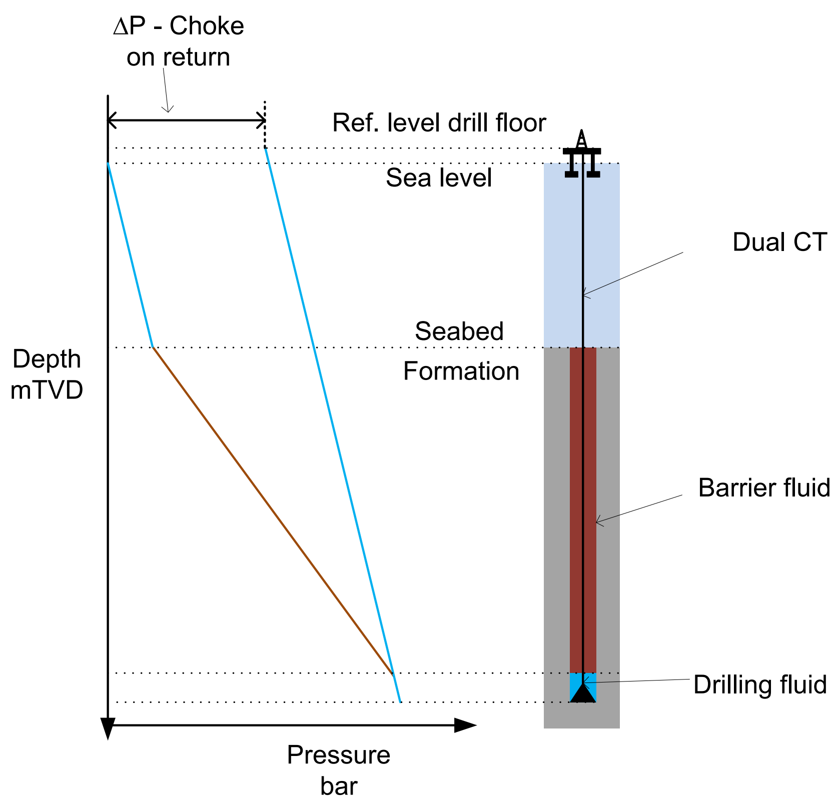


Figure 4-3 DualCTD fluid gradients

Depleted formations can be drilled using light drilling fluid, by still securing the above formation with heavy annulus fluid as illustrated in Figure 4-4¨

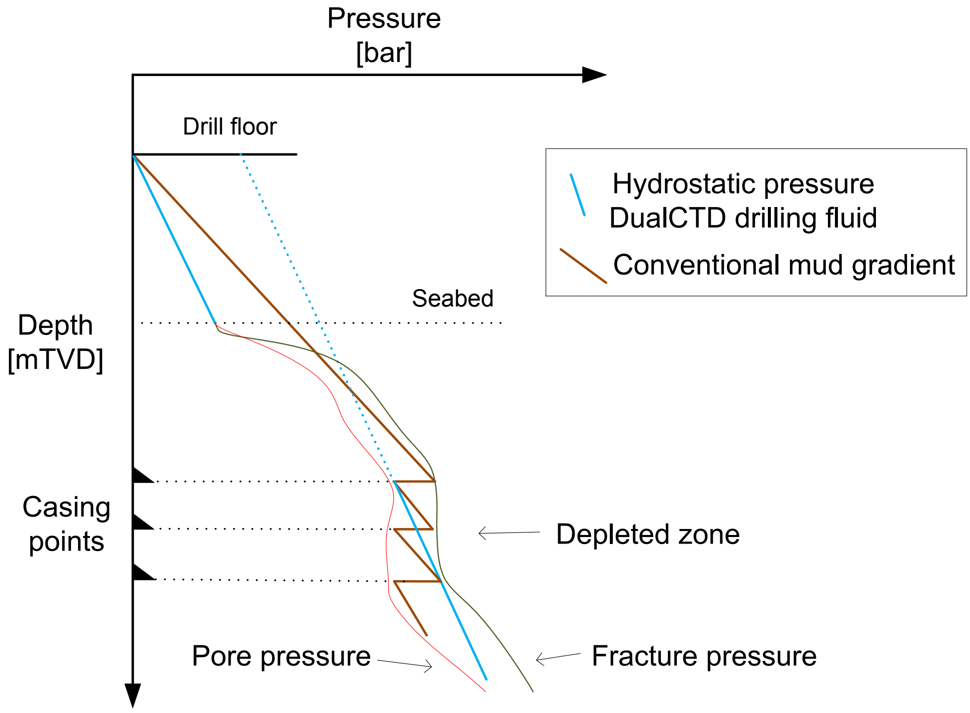


Figure 4-4 Drilling depleted zone with DualCTD

Conventional drilling will require three casing points to drill through the depleted zone in Figure 4-4. The DualCTD system with two fluid systems can be used to drill through the zone with only one casing point placed above the depleted zone. This saves time and money, and the reservoir can be reached with a sufficient diameter of the liner.

The heavy mud in the annulus can act as a second barrier and be used to kill the well in a kick situation. It can also be used to increase WOB by pushing on piston that is connected to the dual CT string

4.3.3. DualCTD Drilling Fluid

The drilling fluid in the DualCTD does not have to provide hydrostatic pressure and borehole stability properties, and can therefore be tailored for hole cleaning capabilities and low ECD. The smaller flowing area of the drilling fluid in the DualCTD concept provides a high frictional pressure loss in the circulating system. The drilling fluid needs also to travel through the entire CT string regardless of the drilling depth, it's therefore important to drill with a low viscous fluid to compensate for the frictional pressure loss. Frictional reducers can be added to the drilling fluid to reduce the pressure loss in the circulating system.

The circulating volume of drilling fluid will also be smaller than in conventional CTD/jointed pipe drilling. Faster kick detection and more efficient well control will be possible with a smaller circulating volume.

Water is selected as the circulating drilling fluid in this thesis. Other light drilling fluids can also be used. Advantages with light and low viscous drilling fluid are summed up as:

- Light drilling fluid is easy to maintain
- Cuttings removal is easy in light drilling fluid
- In case of losses it is easy to supply more fluid
- Low cost fluid
- Lower frictional pressure loss, less pumping capacity needed
- Less abrasive to equipment in the circulating system

The higher frictional pressure loss in the circulating system in DualCTD system can act as a natural choke for the backpressure. High pressure loss over the choke valves can cause abrasion and erosion of the valves.

4.3.4. Separation of the Fluids

The two fluid systems need to be separated for the DualCTD concept to work as intended. An annulus sealing mechanism can be located behind the valve system and the inlet ports for the return fluid to the inner string. The newly drilled formation needs as short exposure time as possible to the low density drilling fluid. The drilling fluid is optimized for hole cleaning and is not designed to keep the formation stable. Optimization of the length of the BHA makes it possible to shorten this length and to place the sealing system as close to the bit as possible.

Three sealing systems are analyzed in this thesis:

- Viscous fluid in the secondary annulus or a viscous pill
- Heavy over light concept
- Mechanical/rubber/brush seal

Viscous barrier fluid/ viscous pill can be used to separate the fluids in the DualCTD concept. This method will be of the same principle as used in mud cap drilling, but in the DualCTD system the drilling fluid is returned to surface inside the dual CT instead of lost to the formation. Mud cap drilling is described briefly in sub section 3. Figure 4-2 show the mixing/interference zone that will form between the two fluids with a viscous BF. The interference zone can be controlled by continuously reading of the downhole pressure and adjusting the height of the fluid columns by choking the return of drilling fluid and by constantly filling BF through the supply line when drilling the well. A backpressure pump on the BF line on the seafloor can be used to increase the BHP with a lower density BF. A choke on the BF supply line as illustrated in Figure 4-2 can be used to reduce the backpressure of the BF at the seafloor. Some mixing of the two fluids in the interference zone will not be a problem as long as the BHP can be controlled in a safe manner. Cleaning of the BF in the interference zone is needed after the operation.

The viscous BF/viscous pill will be the preferred separation method for the fluids in the DualCTD concept.

The Heavy over Light (HOL) concept is described in chapter 3.3.4. Reelwell AS intention with this system is to drill long ERD wells by leveraging the buoyancy potential of a heavy BF and a light circulating fluid with the use of aluminum DDS. The heel of the well path needs to be lower than the toe/drilling section for this system to work. The DualCTD as described in this thesis is not intended for drilling ERD wells, so this HOL separating concept will not be the recommended annulus sealing system.

Mechanical seals that have been used in the other DGDS described in Chapter 3 are:

- Inflatable packers
- Seal with rubber and a brush
- Steel mandrel with over gauge diameter.

Mechanical seals can be used to provide extra WOB by pushing on a piston with the fluid in the secondary annulus, as described in sub section 3.3. UB drilling operations can be performed if the sealing mechanism seals properly with the formation. Mechanical seals can be problematic to install. It can be challenging to get the seals to seal properly in over gauge holes, washout zones etc. The formation needs to have sufficient strength for a mechanical seal to be efficient. Sliding seals will also be exposed to significant wear from the formation. Mechanical downhole seals can also be used as a secondary downhole BOP for increased safety.

4.4. Technical Aspects with the DualCTD Concept

Technical aspects and challenges for the DualCTD concept is presented and discussed in the following sub sections.

4.4.1. Hole Size

The DualCTD concepts primarily application is small hole drilling (8,5" and smaller) by drilling of the lower part of the well into the reservoir section. The use of a 6" bit for drilling a 6" open hole is examined in this concept review. Then a 4,5" or a 5" liner, screens or open hole completion can be installed in the reservoir section for sufficient flow capabilities. Smaller holes can be drilled and completed, but as large diameter reservoir section as possible is preferred in most cases.

4.4.2. DualCTD Size

CT size and mechanical properties used in this thesis are obtained from Schlumberger's I-Handbook (Schlumberger 2015), a free reference book on CT sizes, Casing sizes etc. for the oil and gas industry. See Appendix II for example. The I-Handbook can also perform simple CT collapse calculations.

CT string comes in various sizes, weights, materials and yield strengths. Manufacture procedures of CT strings have improved a lot since the start of the CT era. Today's CT strings are reliable with long life limits.

The size on CT for the DualCTD concept was selected after trial and error in the feasibility study. The CT strings needs to be as small as possible due to limitations on handling weight, reel capacity and bending forces, but still provide sufficient flow capabilities with low frictional pressure drop, mechanical strength capacity and downhole WOB to drill the selected wells.

Two DualCTD string setups are investigated in this thesis. A 3 ½" outer CT with a $2\frac{3}{8}$" inner CT (3,5" x 2,375") are selected as the standard setup for the DualCTD system. A smaller$2\frac{7}{8}$" outer CT with a 2" inner CT (2,875" x 2") setups is also investigated. Different string setups can also be technical feasible. The standard string setup is illustrated in Figure 4-5 below.

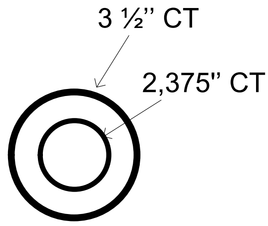


Figure 4-5 Example of CT string setup (not to scale)

Sizes, weights and yield strength of the standard DualCTD setup are given in Table 4-1:

3 1/2" & 2 3/8"	OD	ID	Weight	Wall thickness Nom.	Wall thickness Min.	Grade	Pipe collapse	Pipe body yield load	Pipe Internal Yield pressure	Torsional Yield Strength
	[in]	[in]	[lbm/ft]	[in]	[in]		[psi]	[lbm]	[psi]	[lb.ft]
Inner pipe	2,375	2,025	4,11	0,175	0,167	CT90	5054	74700	8870	4090
Outer pipe	3,375	3,124	6,65	0,188	0,18	CT91	5664	168970	8590	13316

Table 4-1 Specifications for the 3,5" x 2,375" DualCTD string setup

Sizes, weights and yield strength of the smaller DualCTD setup are given in Table 4-2.

2 7/8" & 2"	OD	ID	Weight	Wall thickness Nom.	Wall thickness Min.	Grade	Pipe collapse	Pipe body yield load	Pipe Internal Yield pressure	Torsional Yield Strength
	[in]	[in]	[lbm/ft]	[in]	[in]		[psi]	[lbm]	[psi]	[lb.ft]
Inner pipe	2	1,65	3,41	0,126	0,167	CT90	9641	62290	8870	2814
Outer pipe	2,875	2,563	4,53	0,156	0,148	CT91	5671	114110	9270	7443

Table 4-2 Specifications for the 2 7/8''x2'' DualCTD setup

4.4.3. DualCTD Handling Weight

Weight limitations will be an issue with the DualCTD concept, especially on offshore platforms, drill ships and intervention boats. Weight limitations on lifting and storage capacity offshore are a challenge with today's single string CTD operations as heavy weight and large diameter coils are needed in CTD operations. On Statoil's recent CTD campaign on Heidrun, they had to transport the CT string in two parts and splice it together offshore because of limitations on lifting capacity on the offshore cranes. Total weight of the 2 7/8" CT reel was 45 tons and maximum lifting capacity on the crane was 32 tons (Statoil ASA 2014).

In the DualCTD, weight of the combined system can be the double of an ordinary CTD job, as two strings are used instead of one. The weight of a 4000 m long DualCTD string is calculated for both string setups, presented earlier, in Table 4-3:

String length 4000 m	3,5" x 2,375"	2,875" x 2"
Weight	**[ton]**	**[ton]**
Inner CT	24	20
Outer CT	40	27
Combined Weight	64	47
CT reel	15	15
Total weight	**79**	**62**

Table 4-3 Handling weight of the DualCTD system

The total weight of the system is 79 and 62 ton respectively. With an empty CT reel weight of 15 tons. Compensating measures for reducing the handling weight of the system can be:

- It is possible to splice two shorter coils together at the platform, ref. sub section 2.2.1. Statoil has good experience with this from the CTD campaign on Heidrun (Statoil ASA 2014). However, there is no suitable technique for joining inner CT sections.
- Reel the coils onto the platform from a vessel, boat etc. This is performed with success on the British side of the North Sea, illustrated in Figure 4-6. See paper by: (Davies, et al. 2012) for detailed operation procedure.

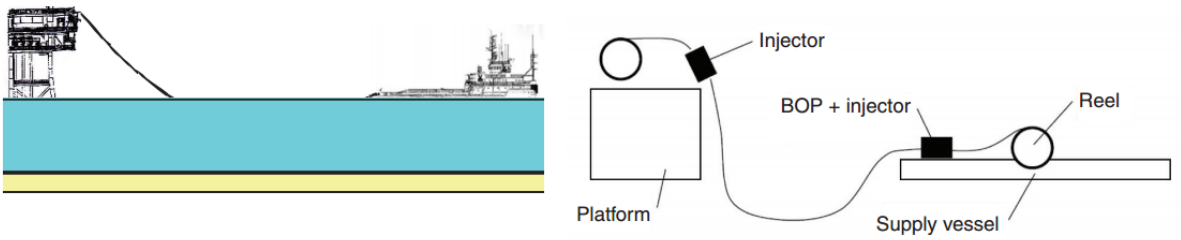


Figure 4-6 Spooling CT from a vessel to a rig (Davies, et al. 2012)

- Transport the two separate CT reels to the platform and insert the inner coil in the outer coil at the platform. Reel out the outer coil in a vertical well and install the inner coil from the top. This may not be feasible and very time consuming, and the least preferred method.

An inner coil of a different and lighter material can be used to reduce the weight of the system. This is not commercially available in the market today.

Smaller concentric CT strings for operations presented in sub section 2.4 are produced with the inner CT string already installed in the outer CT from the factory. This will be preferred installation method for the DualCTD strings. Other methods for installation of the inner string can be: Reel out the strings onshore and the inner CT string can be inserted by pumping it into the outer CT. However, reeling out two 4km long CT strings will be a challenge. There are many good experiences from the industry with pumping wireline cables through CT for downhole telemetry in CTD. These experiences should be looked into for how to insert the inner string in the DualCTD concept.

4.5. DualCTD BHA

The BHA for use in the DualCTD concept needs some special and customized components compared to an ordinary CTD BHA that is described in chapter 2.3.3.

If a live well is the target for the DualCTD operation, restrictions on the length of the BHA, to be able to run it thought the lubricator, will be an important factor in the design. The lubricator is shown in Figure 2-8, this device seals off the annular when inserting CT tools in live wells.

The BHA needs to be specific designed for every DualCTD job. The need of MWD/LWD and steering tools varies for each job. Steering and downhole communication may not be needed in simple vertical wells. The main components in the BHA in DualCTD system are discussed in this sub section. Downhole communication is also studied briefly.

4.5.1. Dual Float Valve

A dual float valve (DFV)/fluid cross over valve is needed in the BHA for guiding and separation of the circulating fluid. The supply drilling fluid must be guided from the outer annulus to the BHA and bit. The return flow with cuttings must be guided from the annulus in the open hole section into the inner string to be circulated back to surface.

A DFV needs to be designed to prevent fluids to flow to surface in an emergency situation if surface equipment fails. In the Reelwell drilling method, the DFV is used to keep the BHP constant during connections, this is not needed in the DualCTD concept.

Reelwell AS's DFV is described in sub section 3.3.1. This DFV has an OD of 8"and is designed for flow rates up to 800 l/min. The size of this DFV is bigger than the hole sizes that the DualCTD concept is intended to drill. A smaller diameter DFV may be challenging to design, but the DualCTD concept is designed for much lower flow rates than Reelwell AS' DDS concept and the DFV need to be designed thereafter.

Main features for the DFV in the DualCTD concept include:

- Low pressure drop in the supply and return flow direction
- Ports big enough to transport cuttings into the inner string
- Check valve installed that act as a secondary barrier, preventing upward flow of well fluids if surface equipment fails
- Reliable design

The DFV in the DualCTD system will not rotate. This can cause challenges with guiding the drilling fluid into the inner string and must be investigated if the same design as Reelwell AS's rotating DFV is selected.

A concept of mud return through a hose in the well was researched in a master thesis on NTNU by Beate Nesttun Oyen (Øyen 2009). A seal with combination of stiff rubber and a brush was found to be suitable to seal off the annulus and guide the fluid flow into a hose. This could be suitable for the DualCTD concept. The system is illustrated in Figure 4-7.

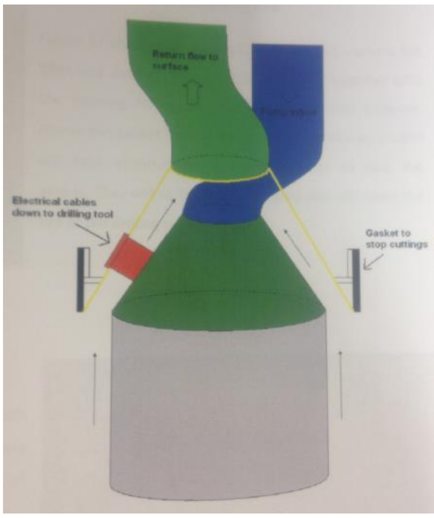


Figure 4-7 Top hat for mud return and supply (Øyen 2009)

4.5.2. DualCTD Mud Motor

CT mud motors are described in sub section 2.3.3. Mud motors for the DualCTD concept needs to be specific designed for each job considering the following:

- Bit and hole size
- Torque and RPM
- Hydraulics, flow rate and pressure loss over the motor

General specifications that are needed are as following:

- High torque and power at low flow rate with low pressure loss

- Compatible with selected downhole tools, bent subs and RSS
- Slim design
- As short motors as possible and flexible design for high dogleg holes
- Transfer little stress to the CT

Stalling torque on the mud motor must be set lower than the torsional yield limit for the CT strings in the DualCTD system. Specifications for CT mud motors used in the calculations in this thesis can be found in 0.

4.5.3. Bit Design

PDC, roller-cone and bi-centered bits can all be used in the DualCTD concept. The bits need to be adapted to the higher RPM from the mud motors and the lower WOB from the CT compared to conventional rotary drilling. The DualCTD concept will use lower flow rates than ordinary CTD and this can cause problems with hole cleaning in front of the bit, flushing of cuttings etc. Bits for the DualCTD concept should be selected and optimized in cooperation with bit service companies.

4.5.4. Steering

Simple bent sub or advanced 3D RSS can be used in DualCTD. A smaller version of a conventional RSS was used in drilling of drainage holes in Statoil's CTD campaign on Heidrun, this worked as intended.

4.5.5. Separation Tool

In case of stuck BHA a separation tool is needed in the upper part of the BHA as a contingency if the BHA cannot be retrieved. This allows the BHA located above the separation sub to be retrieved and recovered together with the CT string from the well. The rest of the BHA needs to be fished in a later run. The separation tool can either be tension released with shear pins, hydraulic activated by change in flow rate or by a ball. Ball activated release mechanism require passable ID's above the separation tool, this can be problematic in the DualCTD system with the supply drilling fluid in the annulus between the DualCTD strings and the DFV located as the first tool in the BHA. Flow activated or shear pins will be the preferred methods to release the string.

4.6. Downhole Communication

Downhole communication is essential for drilling of designer wells. Communication with RSS, MWD/LWD- and pressure reading tools is needed. Live pressure reading on downhole pressure will be important in the DualCTD to be able to monitor and control the BHP. High data transfer rates with the downhole tools can make it possible to continuous log the formation and steer the bit with the formation and the pay zone as drilling proceeds.

Three different ways to communicate with the downhole tools is presented in this sub section:

1. Communication through wireline
2. Wired string/ use the concentric CT strings as conductors
3. Mud pulse communication

Communication through Wireline has been used with success in CTD, either with a wireline cable pumped through the string, or placed outside the string. Wireline communication with the downhole tools gives high speed data transfer rates and the ability to provide electrical power downhole through the cable.

The DualCTD setup is a complex system with the coil in coil setup. Adding another cable to the system can cause problems; 1) A wireline cable in the inner coil is to be avoided because it will reduce the flowing area and it can block the cuttings and fluid flow causing the coil to get plugged. 2) The inner coil needs to be free of obstacles if the BHA gets stuck and a wireline cutter needs to be run inside the string to retrieve the coil. Pumping of darts/balls to activate downhole tools and release tools will be impossible with a cable inside the coil. 3) The wireline cable in the annulus between the two CT strings will reduce the flowing area. The wireline cable can also be squeezed between the two coils in bends, curves and on the reel where the coils are suspected to deform and be oval. Figure 4-9 below illustrates the problem with a wireline cable in annulus between the two coils. 4) It will also be difficult to install the wireline cable in the annulus with small clearance between the coils on the reel. 5) An extra cable will add weight to the already very heavy system. Communication through wireline will not be the preferred downhole communication method.

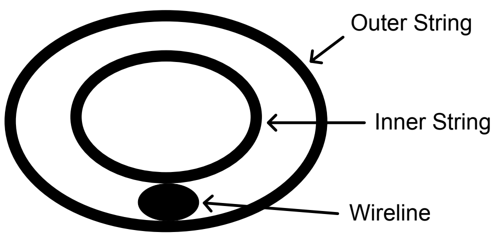


Figure 4-8 Oval DualCTD string with Wireline cable

Wired CT/use the CT string as conductors can be a solution if high data transfer rates are needed in the DualCTD operations. The inner string will be electrically insulated from the outer pipe with a coating that prevents conductivity between the two pipes. Reelwell AS have developed this system with their DDP and field tests has shown promising results. The system gives high rates, real-time data transmission and the ability to transfer large amounts of power to the downhole tools (Drilling Contractor 2010). The system is illustrated in Figure 4-9.

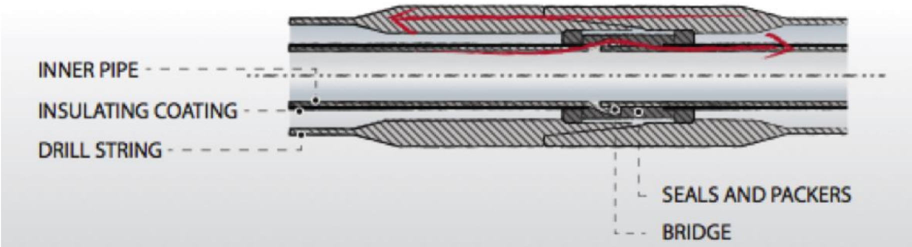


Figure 4-9 Communication using the DDS as conductors (ReelWell AS u.d.)

Mud pulse communication is the standard way to communicate with the BHA in conventional drilling. Pressure pulses in the mud are generated and sent from surface down to the tools, and back from the tools to surface. This method gives lower bit rates than the other systems, but it is less complex. CT BHA's have been developed from drilling BHA's and mud pulse technology is proven to be reliable for CTD. Baker Hughes had no problems with mud pulse communication during CTD on Heidrun (Statoil ASA 2014). Reelwell AS has also proved that mud pulse communication is suitable in their dual drill pipe drilling method. Mud pulse communication will be the preferred method in DualCTD.

4.7. Hydraulic Model

Hydraulic simulations are conducted in this thesis to compare the flow rate to the frictional pressure loss and fluid velocities for the two proposed DualCTD designs. Fluid velocities are directly related to the hole cleaning capacity of the operation. Hole cleaning is more effective at higher flow rates. A higher flow rate however, will lead to higher frictional pressure loss which could be higher than the design limits for components in DualCTD operation.

A hydraulic model is developed on the basis of the equations given in chapter 2.5.6. This model is used to calculate the pressure drop for the DualCTD concept. The can be found in Appendix III.

Water is used as drilling fluid and following assumptions are made for the calculations in the model:

- Drilling fluid is Newtonian fluid
- Drilling fluid in each part of the circulation system is turbulent flow
- Drilling fluid is incompressible
- The inner CT is concentric in the outer CT
- The CT string surface is smooth
- No cuttings in the return flow in the calculations

Pressure loss & cuttings velocity vs flow rate for a 4000 m long well with 200 m coil left on the reel is shown in Figure 4-10 (same well path as in the example in Figure 5-1.) The calculations are conducted on two different DualCTD setups, the standard 3 ½" x 2 3/8" setup as given in Table 4-1 and a smaller 2,875"x 2 " CT as given in Table 4-2.. Open hole size is 6". Other input parameters for the model can be found in Appendix III.

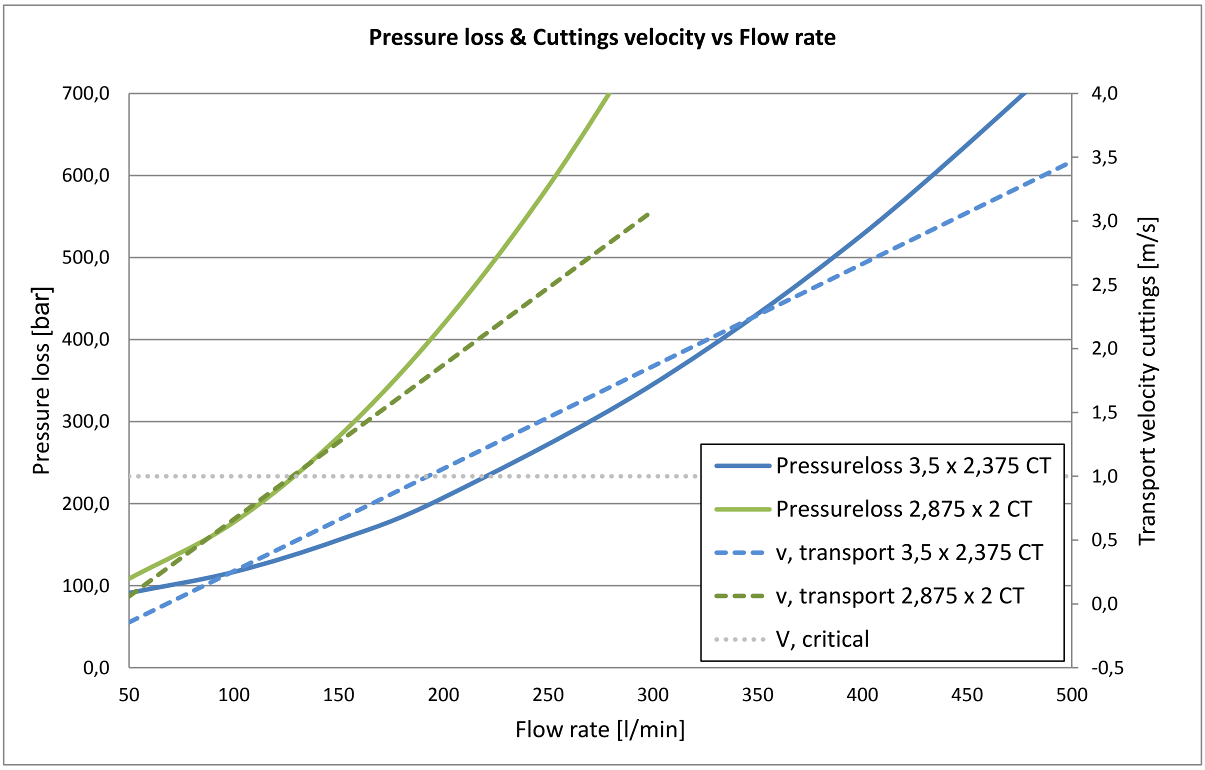


Figure 4-10 Pressure loss & Cuttings transport velocity vs Flow rate

The blue lines represent the pressure loss and cuttings velocity for the 3,5"x 2,375" DualCTD setup. The green lines represent the pressure loss and cuttings velocity for the smaller 2,875"x 2" DualCTD option.

The grey dotted line represents the minimum transport velocity needed to transport cuttings out of the well. Critical transport velocity for a 8,5" hole in conventional drilling is: >1 m/s

(S. Sangesland 2008). The transport velocity for the cuttings in the DualCTD concept has to be higher than this because of low viscosity of the drilling fluid. The transport velocity is calculated with the equations in sub section 2.5.4. The fluid velocity of the cuttings inside the inner string is linear related to the diameter and flowrate.

The pressure loss increase as the flow rate increases. Optimum flow rate for the DualCTD is a flow rate that gives sufficient hole cleaning and with a required pumping pressure that is within the pressure limits for the system. Collapse and burst pressures for the dual CT are discussed later in this chapter.

Pressure loss for the BHA components, BHA, Motor and bit is set to 20 bar, 31 bar and 30 bar respectively, for both DualCTD options in Figure 4-10. A minimum flow rate and pressure drop is also required to operate the downhole components. Specifications for CT mud motors form a vendor are given in 0. The pressure drop over BHA, mud motor and bit does not vary with flow rate in the calculations in this thesis.

Minimum required flow rate for the 2,875” x 2” CT to get a sufficient transport velocity of cuttings is, from the graph, higher than 130 l/min. This gives a frictional pressure drop of 235 bar in the circulating system.

Minimum required flow rate for the 3,5” x 2,375” CT to get a sufficient transport velocity of cuttings is, from the graph, higher than 200 l/min. This gives a frictional pressure drop of 207 bar in the circulating system.

Pressure loss for the components in the circulating system for the 3,5”x2,375” DualCTD setup with flow rate of 200 l/min are given in Figure 4-11:

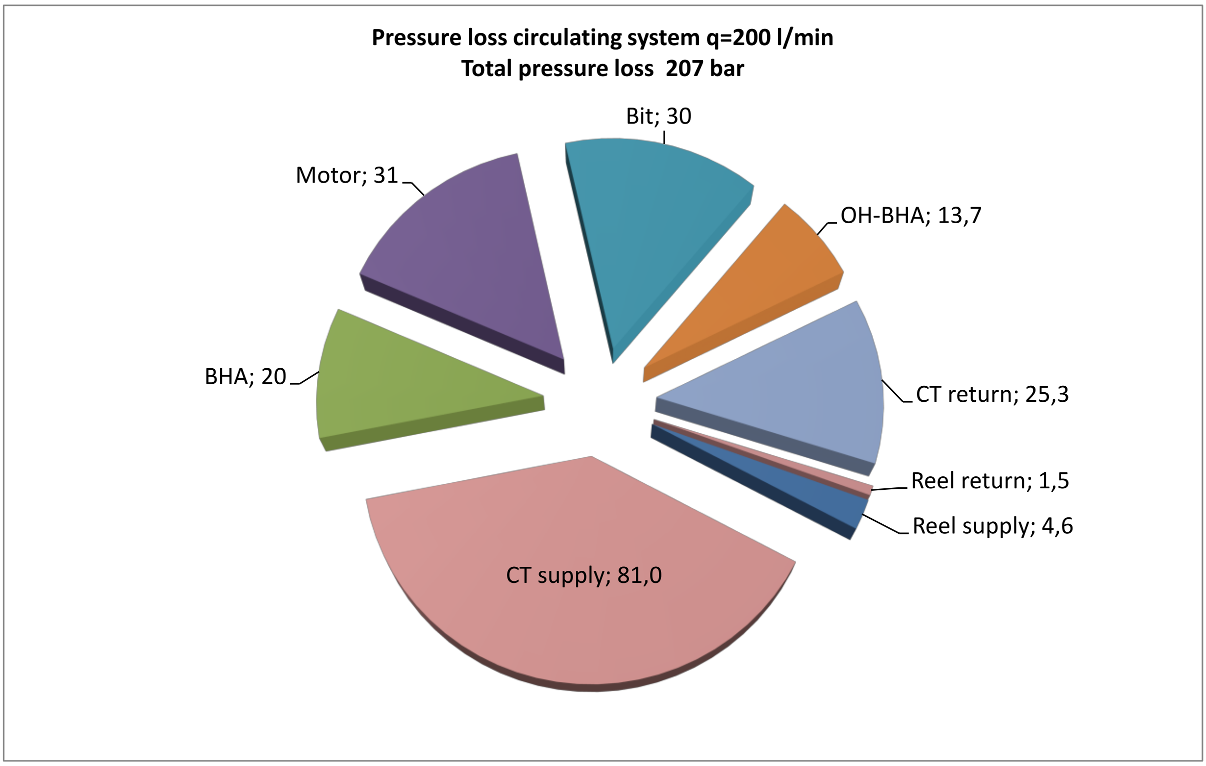


Figure 4-11 Pressure loss q=200 l/min. 200m CT on the reel, 4000m CT in the well

The highest pressure drop in the system is in the CT supply line. The flow path for the supply fluid is in the annulus between the two CT strings with low annular clearance. Frictional drag from the wall in the inner string and outer string will affect the pressure loss in this conduit.

Pressure loss for the system in the same well, with 1200m CT left on the reel and 3000 m in the well (an example depth for kickoff from vertical for drilling of drainage holes) is given in Figure 4-12

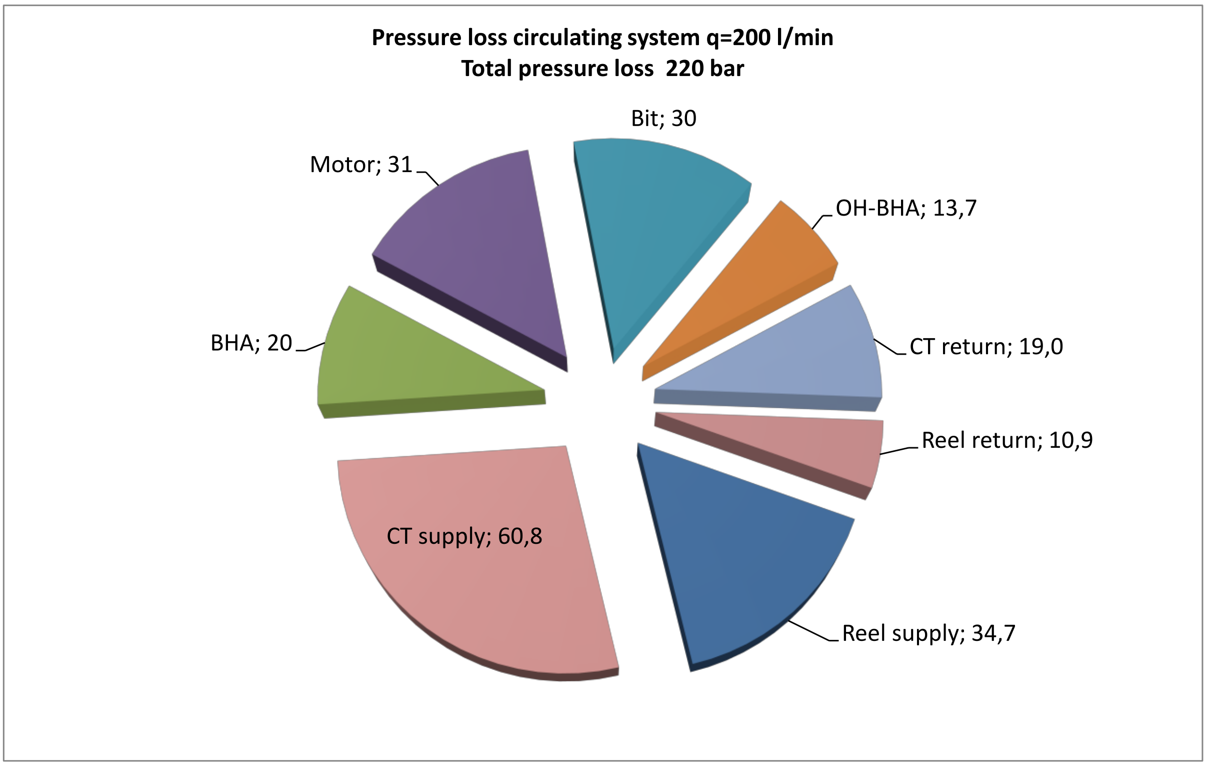


Figure 4-12 Pressure loss q=200 l/min. 1500m CT on the reel, 3000m CT in the well

Total pressure loss is in this case has increased from 207 bar to 220 bar. This is because the reeled coil has a higher pressure loss than a straight coil due to increased friction. The friction factor of the spiral part of the CT depends on the CT diameter and diameter of the CT reel.

4.7.1. Hole Cleaning

Hole cleaning is one of the main challenges in CTD. Statoil had problems with hole cleaning in their CTD campaign on Heidrun, ref sub section 3.6. Low flow rates, big annulus area, low viscosity fluids and no string rotation to agitate the cuttings are some of the main challenges and limitations for proper hole cleaning in CTD.

The DualCTD concept provides cutting transport in a separate flow conduit from the bottom of the well, this will give very effective hole cleaning. The small flowing area in the flow conduit inside the CT string gives high fluid velocity with low flow rates. The flow conditions will also be turbulent inside the inner string. The cuttings are expected to be suspended in the drilling fluid in the short open hole section over the BHA, since the OD of the BHA is relative large. High velocity is needed to lift cuttings in the circulation system as the drilling fluid has low viscosity to lower the frictional pressure loss. Viscous pill and sweeps can be pumped to lift cuttings if hole cleaning is a challenge.

Accurate formation analysis can be performed on the good quality cuttings at surface in the DualCTD system. Cuttings travel fast to surface inside the dual CT. Little mechanical crushing and grinding of the cuttings are expected as the cuttings are exposed to the formation in just a short interval. Mixing of the cuttings from different formations is also eliminated. Reduction in contact between the cuttings and formation will also lead to reduction in formation damage and damage of the filter cake.

The Reelwell drilling method has proved very good hole cleaning with the dual flow conduits. Experiences from this system should be implemented in the hole cleaning system for the DualCTD concept.

4.7.2. Cutting Transport and ROP

Analysis of maximum allowable cuttings concentration (CC) and minimum fluid velocities for cuttings transport is conducted in this section to model the maximum ROP for the DualCTD concept. Equations given in sub section 2.5.3 are used to calculate the ROP for a 6” and 4,5” bit.

Maximum CC is set to 4%. CC above 4% can cause hole cleaning problems, ref. sub section 2.5.3. 2% CC is also illustrated to get a picture of the ROP for lower CC rates. A CC of 4% should be within the hole cleaning capabilities of the DualCTD system.

ROP relates on many variables as; formation, bit, WOB, RPM etc. The analysis in this sub section examines only the hole cleaning capabilities for the different DualCTD string setups in the simulations of maximum ROP.

The lower limit of the flowrates for the DualCTD setup is set to the minimum allowable cuttings transport velocities that will give sufficient cutting lifting capacity, given in Figure 4-10. The upper limit of the flow rates is set to the maximum burst and collapse pressures for the respective DualCTD setup, this is discussed later in this chapter.

Flow rate vs. ROP for 6” and 4,5” bit is calculated in Figure 4-13 and Figure 4-14:

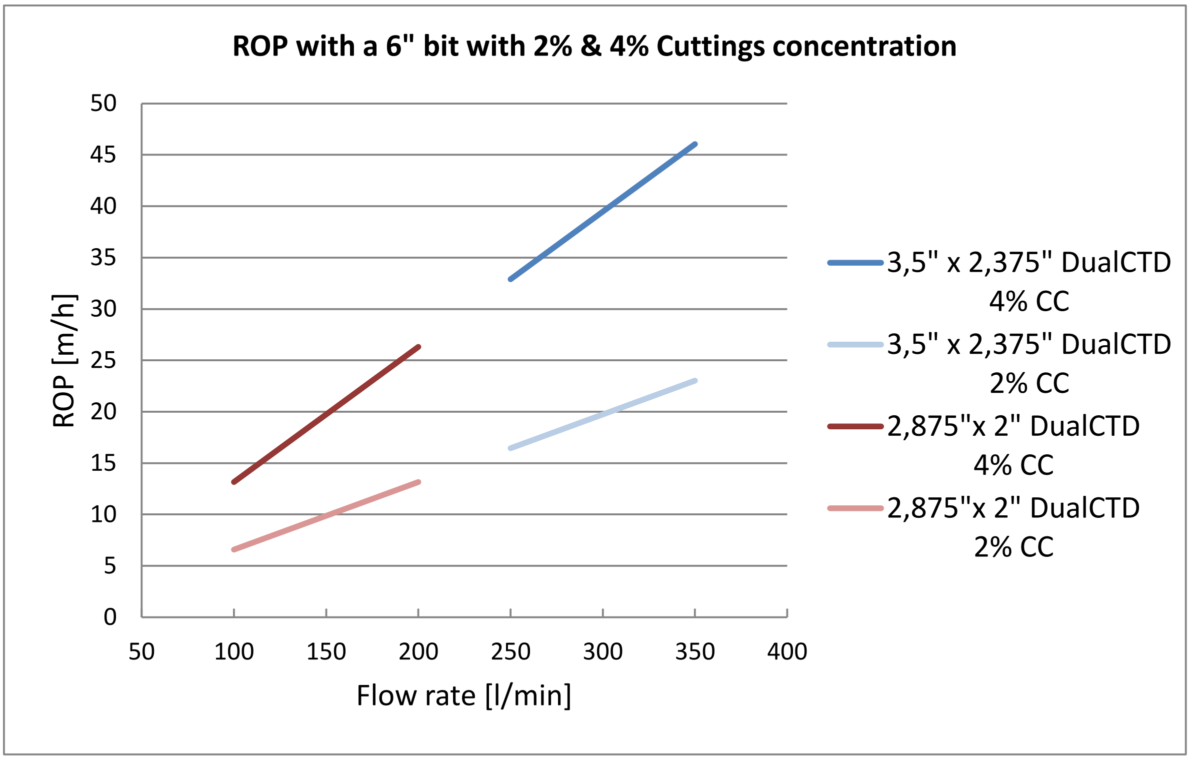


Figure 4-13 ROP 6in bit, 2% & 4% cuttings concentration

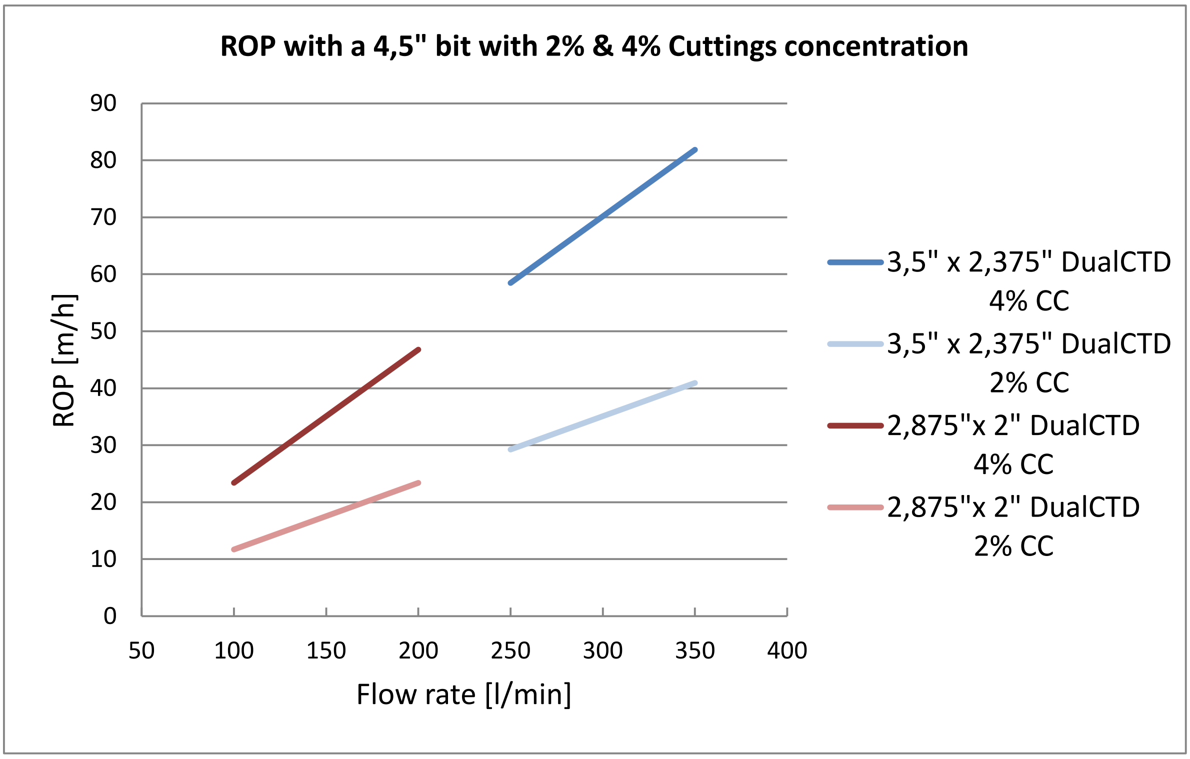


Figure 4-14 ROP 4,5in bit, 2% & 4% cuttings concentration

ROP for the 6” bit is given in Figure 4-13. The ROP will be in range of 33-43 m/h for a CC of 4% for the 3,5”x 2,375” DualCTD setup. The smaller 2,875” x 2” DualCTD setup gives a ROP from 13-26 m/h.

ROP for the 4,5” bit is given in Figure 4-14. The ROP will be in range of 59-82 m/h for a CC of 4% for the 3,5”x 2,375” DualCTD setup. The smaller 2,875” x 2” DualCTD setup gives a ROP from 24-47 m/h.

The results shows that the smaller 2,875” x 2” DualCTD setup will only be able to drill at half of the ROP as the bigger 3,5”x 2,375” setup. This is important factors to take into account when selecting the DualCTD setup. A 1000m long 4,5” wellbore can be drilled in 12 hours with the largest DualCTD setup, 21 hours are needed if the smaller setup is selected, if only cuttings carrying capacity is considered.

A ROP of 30 m/h is assumed to be “normal” penetration rates in conventional drilling. The DualCTD is, from a hole cleaning perspectives, able to drill at same speeds as conventional drilling.

ROP in DualCTD has to be monitored to not exceed the maximum cuttings carrying capacity of the drilling fluid. Bad hole cleaning can cause serious problems and in worst case a stuck DualCTD string that needs to be cut and abandoned in the hole.

Big cutting pieces from the bit can block the flow paths to the inner string in the DFV. This will stop the flow and the drilling process needs to be canceled. Small cuttings are therefore desired in the DualCTD system. High rotation speed of the bit from the mud motor together with low WOB will produce small cuttings. The bit should also be optimized to produce small cutting pieces.

4.7.3. Fluid Volumes

Circulating drilling fluid volume for the DualCTD concept will be significant reduced compared to conventional CTD and conventional rotary drilling. The circulating volume in the DualCTD setup is the volume inside the dual CT string and across the BHA in the open hole. Rest of the well volume will be filled with BF.

Mud volumes for the example well in Figure 5-1 with the DualCTD concept in the standard 3,5”x 2,375” setup and conventional CTD are calculated in Table 4-4 & Table 4-5.

DualCTD concept

Circulating volume, 3,5" x 2,375" DualCTD	Flow area	Section length	Circulating volume
	[m2]	[m]	[m3]
Inner coil	0,0021	4170	8,66
outer coil	0,0024	4170	10,15
6" OH-BHA	0,0120	30	0,36
Total			**19,18**
Barrier fluid	Flow area	Section length	Volume
	[m2]	[m]	[m3]
6" OH-coil	0,0120	970	11,7
8,5" Casing-Dual CT	0,0304	3000	91,2
Total			**102,9**

Table 4-4 Mud volume DualCTD

Conventional CTD

Circulating volume:	Flow area	Section length	Circulating volume
	[m2]	[m]	[m3]
2,375" Inner coil	0,0021	4170	8,7
6 "OH-BHA	0,0120	30	0,36
6" OH-CT	0,0154	970	15,4
8,5 casing-CT	0,0338	3000	101,3
Total			**125,7**

Table 4-5 Mud volume conventional CTD

The calculations shows that the circulating volume is reduced from 125,7 m^3 for conventional CTD, to 19,2 m^3 for the DualCTD setup. This is a reduction in circulating volume of 85%. The reduction in circulating volumes requires less handling, mud cleaning and storage equipment for drilling fluid. Bottoms-up times will also be significantly reduced.

However, 103 m^3 of BF is needed to fill up the secondary annulus. Separate storage, pumps and handling equipment are needed to take care of this extra fluid. This requires custom design of surface facility, extra logistics and more crew and time is needed in installation of the DualCTD system.

The riser is not taken into account in these calculations. A smaller riser can be used in the DualCTD concept, or the riser can be completely eliminated if the DualCTD operation is designed that way.

4.8. Buckling

Buckling is one of the main limitations with CTD compared to conventional drilling. Additional heavy weight pipes are often added in the vertical section of the wellbore in conventional rotary drilling (jointed pipes) to prevent buckling of the string. This is not possible in CTD, as the CT is one continuous string. Lighter CT strings with thinner wall thickness buckles faster than thicker strings.

The submerged weight of the CT strings will have influence on the buckling calculations. A higher unit weigh will increase the buckling resistance for the CT string. Buoyancy for the different CT string setups are calculated with the equations in sub section 2.5.7 and given in Table 4-6:

Case	Coiled tubing			Mud weight		Buoyancy	Submerged weight
	OD, outer	OD, inner	Weight	DF	BF		
#	[in]	[in]	[N/m]	[kg/m3]		β	[N/m]
1	3,5	2,375	137,4	1000	1700	0,60	82,7
2	3,5	2,375	137,4	1700		0,771	105,9
3	2,875	2	77,9	1000	1700	0,625	48,7
4	2,875		44,4	1700		0,771	34,2

Table 4-6 Buoyancy calculations

The DualCTD setup with dual mud systems has a lower submerged unit weight than for the single mud system. This is because the fluid inside the strings is lighter than the BF on the outside and it will therefore increase the buoyancy.

Critical buckling loads for sinusoidal and helical buckling in vertical and horizontal wellbores for four string setups, case 1-4, are calculated in Table 4-7 using equations from sub section 2.5.9.

Case	Coiled tubing			Mud weight		Vertical			Horizontal	
	OD, outer	OD ,inner	Weight	DF	BF	F,cr,b	F,hel,b	F,helt,t	F,cr	F,hel
#	[in]	[in]	[N/m]	[kg/m3]		[kN]	[kN]	[kN]	[kN]	[kN]
1	3,5	2,375	82,7	1000	1700	3,2	7,1	0,18	39,6	72,4
2	3,5	2,375	105,9	1700		3,8	8,3	0,21	44,8	81,9
3	2,875	2	48,7	1000	1700	1,8	3,9	0,10	19,9	36,4
4	2,875		34,2	1700		1,3	2,8	0,07	15,3	28,0

Table 4-7 Buckling calculations

Critical buckling calculations in Table 4-7 shows that the CT string will easily buckle in vertical wellbores. The sinusoidal and helical buckling loads are very small, much smaller than those in horizontal wellbores. Only helical buckling will be discussed in this thesis, challenges with sinusoidal buckling has showed not to be as significant as the lock up problems induced with helical buckling.

Buckling resistance for case # 1, with heavy BF and light Drilling Fluid (DF) is smaller than for case # 2 where the BF and DF is of same density. The submerged unit weight is smaller for the dual mud system and this lowers the CT's resistance to buckling.

Table 4-7 shows that the top helical buckling load, *F,hel t*, is very close to zero in the calculations. This is assumed to be the "neutral point" in the string when it is helical buckled in vertical wellbores.

Case 3 is the smaller option for the DualCTD concept. This case has lower buckling resistance than the standard string setup in case 1. This is because the combined cross section steel area of the dual CT is smaller than for the bigger setup.

Case 4 is for a conventional CTD setup with one CT string. Critical buckling resistance for this setup is smaller than for all the DualCTD cases. Statoil used a 2 7/8" CT for their CTD campaign on Heidrun, same as the CT size in this case.

Weight of the BHA is not taken into account in the calculations in this thesis, only the submerged unit weight of the CT strings is used. The unit weight of the BHA is assumed to be higher than for the dual CT strings, this will increase the axial load, but the frictional drag in the horizontal section will also be increased.

4.8.1. Lock-up of the CT

"Lock-up" is the condition reached when the WOB or packer load cannot be increased by "slacking-off" weight at surface, or when the CT cannot be pushed further into the wellbore with increased axial pushing force. The "lock-up" axial force varies with the wellbore design and string configuration.

Frictional drag and helical buckling development are different for different wellbores. The helical buckling starts from the bottom or at the kickoff point in vertical wellbores. The helical buckling starts from the pushing "top" in horizontal and inclined wellbores. CT in buildup sections usually does not buckle, and therefore there is no additional frictional force due to helical buckling.

Maximum transmitted bottom load in vertical wellbores is calculated with equations in sub section 2.5.8 for case 1-4 and plotted in Figure 4-15, friction factor is set to 0,2 and wellbore diameter is 6” :

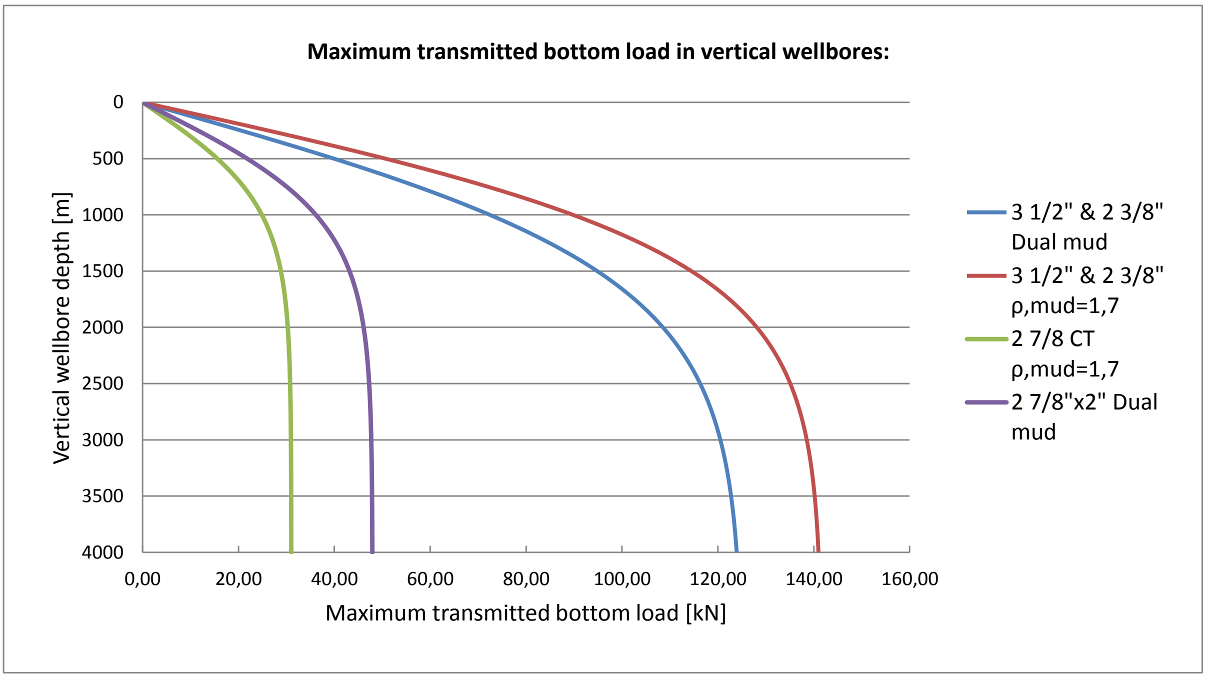


Figure 4-15 Maximum transmitted bottom load in vertical wellbores

The lines in Figure 4-15 illustrate the maximum transmitted bottom load in vertical wellbores. Bottom load increase until the force exceeds the critical helical buckling limit for the CT setups. The frictional drag will increase dramatically when helical buckling occurs and the strings will go into a “lock-up” condition. Transmitted bottom load cannot be increase much after helical buckling of the strings. The vertical lines on the plot illustrates when the strings are helical buckled.

The transmitted bottom load is highest for the 3,5”x 2,375” string with the single mud weight. The same string type with a dual mud system can put down 15 kN less bottom load in vertical wellbores, this is because its more buoyant and has less weight to apply at the bottom. Ca. 12,6 ton WOB is possible to apply downhole in vertical wells of more than 3000m vertical depth with the DualCTD system in a 3,5” x 2,375” setup. This is more than enough for drilling with 8,5” bits and smaller.

The smaller 2,875” x 2” DualCTD setup can apply around 4,9 tons WOB in 2000 m and deeper vertical wells. This is enough WOB to drill with a 6” bit. Required WOB for CTD is from experience around 2,2 kN/in (500lbf/in), this gives a required WOB of 1,35 tons for a 6” bit. WOB must be optimized together with bit and mud-motor service companies for every case.

The Ordinary CTD string with an OD of 2,875” gives a maximum transmitted bottom load in vertical wellbores of around 3 tons.

Maximum horizontal reach that can be drilled for the cases in Table 4-7 is calculated and plotted in Figure 4-16. Equations from sub section 2.5.8 are used to calculated the transferred axial load through a build section with a radius of 127 m (45°/100m build rate). The string is assumed not to buckle in the build section. WOB is set to 13,3 kN (2000lbm), friction factor is 0,2 in the cased vertical section and 0,3 in the open hole build and horizontal section. The well is drilled with a 6” bit from the kick-off point from the vertical section:

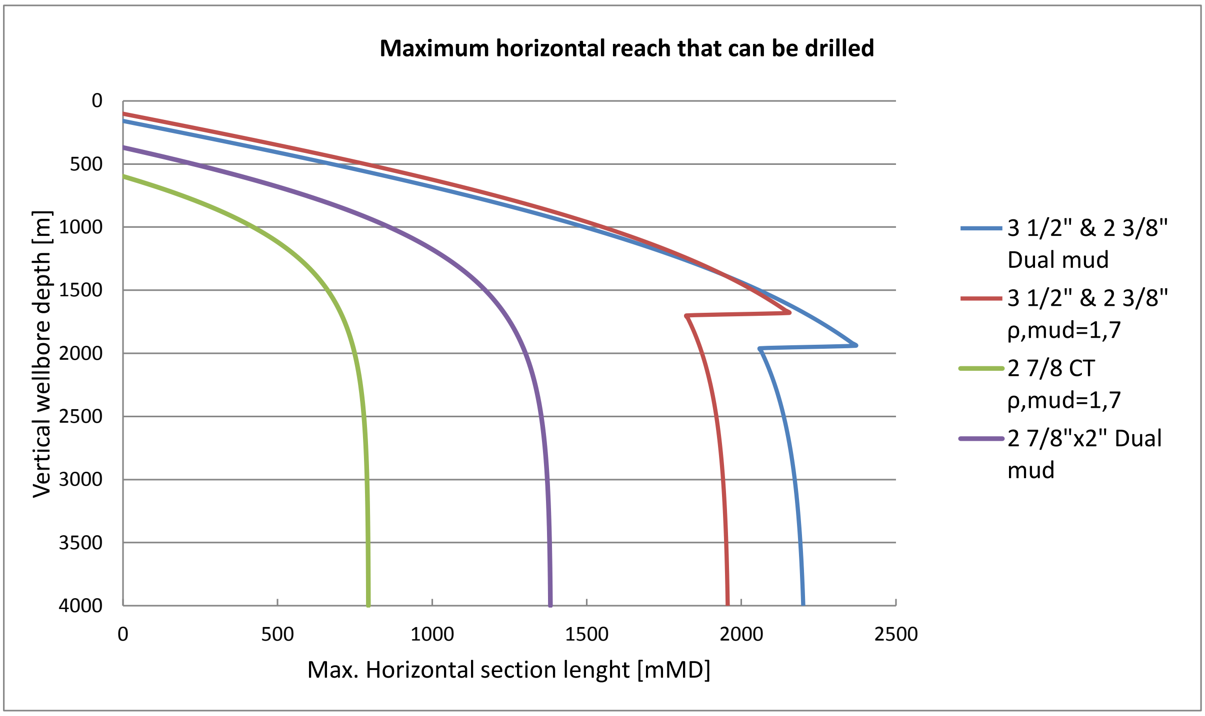


Figure 4-16 Maximum horizontal reach that can be drilled

The lines in Figure 4-16 illustrate the maximum horizontal length than can be drilled with the different string setups. The transmitted bottom load from Figure 4-15 is transferred through the buildup section and pushes the bit into the horizontal section. The strings can be pushed into the horizontal wellbore until the axial pushing force required exceeds the critical helical buckling limit for the CT setups, given in Table 4-7. The frictional drag will increase dramatically when helical buckling occurs and the strings will go into a “lock-up” condition. The strings will then buckle in the beginning of the horizontal section and the bit weight cannot be increase much as the pushing force is increased. This can be seen from the figure as the sudden shifts in horizontal reach for the 3,5” x 2,375” setups (a smoother transection from non-buckled to buckled state will be the case in the field).

The smaller 2,875” x 2” and the 2,875” CT string setups will not exceed the critical buckling force in the horizontal section, their maximum horizontal drilling length are limited by the maximum transmitted bottom load from Figure 4-15. Vertical lines on the plot illustrates when the strings are helical buckled, either in the vertical or horizontal section, or in both.

Figure 4-16 illustrate that the 3,5” x 2,375” DualCTD setup is able to drill a 2200 m long horizontal sections when it uses the heavy BF and lighter drill fluid, blue line. The DualCTD setup with equal mud weighs inside and outside the dual CT, red line, is only able to drill a 1950 m horizontal section. The transmitted bottom load is larger for the single fluid setup, illustrated in Figure 4-15, but the buoyancy effect on the DualCTD concept will reduce the frictional drag and therefore increase the horizontal drilling length.

The smaller 2,875” x 2” DualCTD setup is only able to drill around half the horizontal length as the bigger 3,5”x 2,375” DualCTD setup. However, the horizontal length this setup is able to drill is in most cases long enough for drilling of drainage holes.

Horizontal reach will be greatly increased for both the small and bigger DualCTD setup compared to the conventional CTD setup, illustrated in green in Figure 4-16. The cross-section area of the DualCTD strings are larger, this will increase buckling resistance. The unit weight of the strings is also larger, this will increase the transmitted bottom load. The buoyancy effect from the dual fluid densities will reduce the frictional drag and increase the drillable horizontal length.

4.9. Torque and Drag

Torque is generated downhole from rotation from the mud motors that rotates the bit. Torque depends on the bit size, RPM, WOB and formation properties. The downhole motor stall torque should be no larger than the maximum operating toque for the DualCTD system. Torque limits for the CT strings are given in Table 4-1 and Table 4-2. Usually, torque in CTD is not a significant limitation unless large hole drilling is performed with small diameter CT strings. The maximum torque limit in the DualCTD mud motor should be set to the outer string maximum operational torque. The torque limit for the combined DualCTD system needs to be investigated further.

Hook load when RIH and POOH must not exceed the maximum pipe body yield load for the CT strings. Maximum pipe body yield loads are given in Table 4-1 & Table 4-2.

Hook load (injector load) when POOH for the 3,5” x 2,375” DualCTD string is calculated for the example well in Figure 5-1. The discrete drag model for curved borehole is used and the curved section is threated as one element. Friction factor is set to 0,3 in the open hole section. The maximum axial load from the string when POOH is given in Table 4-8.

F1 = WOOB	0	[kN]
F2 BHA	24	[kN]
F2	73	[kN]
N	-103	[kN]
F3	116	[kN]
F4	364	[kN]
Maximum injector load	**364**	**[kN]**
Axial load capacity outer string	**783**	**[kN]**

Table 4-8 Injector load and axial load capacity

Calculations in Table 4-8 show that the maximum injector load will be 364 kN. The load capacity for the outer string is 783 kN. The Axial load capacity of the outer string is sufficient to carry the load of both string and the BHA when POOH.

Hoisting the DualCTD string may be a challenge if the injector only grips on the outer coil. The combined weight of the inner and the outer CT will then have to be carried by the outer CT. The CT will not be connected elsewhere than at the BHA and at inside the reel.

If the inner CT is in tension from the surface, it will most likely hang on the gooseneck, and not in the injector head, as this only grip around the outer CT. This will put excessive forces on the gooseneck and the inner coil can deform or be oval. This is illustrated in Figure 4-17. Deformation and ovality of the inner CT string will decrease its collapse resistance dramatically, this is discussed more in sub section 4.10. Connection of the inner and outer string along the length of the CT string can be challenging. The inner strings behavior across the gooseneck and the possibility to centralize and connect the inner string in the outer string needs to be investigated further.

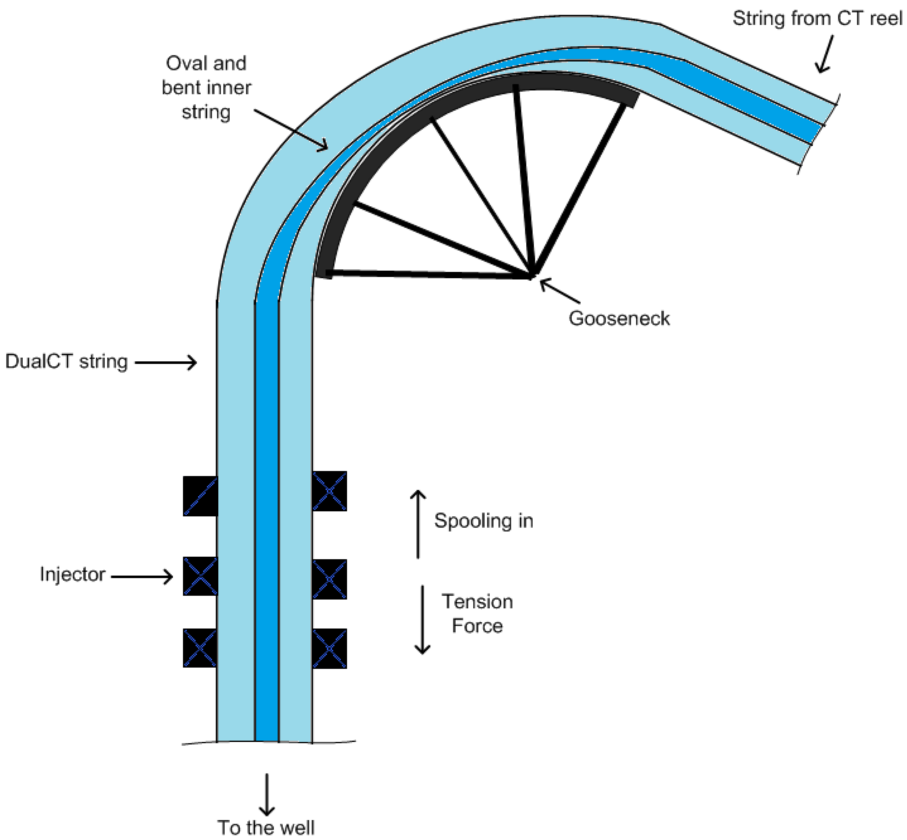


Figure 4-17 Bending forces when running the dual CT over the gooseneck

4.10. Collapse and Burst Ratings of the CT

The burst and collapse pressures for the DualCTD strings will limit the maximum flow rate for the system in deep wells. Higher flow rates gives higher frictional pressure loss and the differential pressure over the CT string can make them burst or collapse. Axial load applied at the injector when the strings are in tension and ovality of the CT will decrease the collapse resistance.

The worst case scenario for the DualCTD concept with supply through the outer string and return through the inner string will be: Collapse of the inner string and burst of the outer string. Drilling fluid is pumped at high pressure from surface through the outer string and returns in the inner string with low pressure. If reverse circulation is needed, burst of the inner and outer string will be the current failure criteria.

Worst case for collapse of the outer CT will be at the bottom of the well when the circulation is stopped. The DualCTD string is filled with a light fluid and a heavy static fluid is located in the secondary annulus on the outside. This will give a high differential pressure across the outer CT

Maximum differential pressure at the bottom of a 3000m TVD well with 1,7 specific gravity. BF and 1 specific gravity drilling fluid is given as:

sg. BF	sg DF	TVD	delta P
[g/cm3]	[g/cm3]	[m]	[bar]
1,7	1	3000	206

Table 4-9 Maximum differential pressure at 3000 m TVD

Burst and collapse pressure for the CT is calculated using the equations in Appendix IV. Ovality of the CT is set to 2%, Pressure inside is set to 0 for worst case scenario and axial load is set to 50kN. Safety factor used is 0,8. The calculated results are compared with results from Schlumberger’s I-handbook in Table 4-9

			Calculated		Schlumberger’s I-handbook	
String setup			3,5" x 2,375"	2,875" x 2"	3,5" x 2,375"	2,875" x 2"
Inner coil	Collapse	[bar]	341	430	362	381
	Burst	[bar]	689	814	873	918
Outer coil	Collapse	[bar]	204	200	211	211
	Burst	[bar]	507	508	592	639

Table 4-10 Burst & Collapse pressures for the two DualCTD setups

Table 4-9 shows that the collapse pressure for the inner CT and outer CT is the limiting factor for both string setups. The maximum pressure for the 3,5” x 2,375” DualCTD system has to stay below 341 bar. The maximum pressure for the 2,875” x 2” DualCTD system has to stay below 430 bar. CT strings with larger wall thickness can be used to improve the collapse and burst resistance, but this will lead to heavier CT strings, smaller flow area and increased frictional pressure drop.

Collapse pressure for the outer strings is below the maximum differential pressure at 3000 m TVD.

Collapse pressure for CT strings varies with ovality, axial load and internal pressure. A sensitivity analysis is conducted to describe the effects of these variables in Figure 4-18, Figure 4-19 and Figure 4-20.

Calculated results for burst and collapse pressured are lower than the once calculated in Schlumberger’s I-Handbook, but not far off. Correct collapse and burst calculations are important for the design of the DualCTD operation. The service companies that deliver the DualCTD string needs to simulate the calculations for correct results.

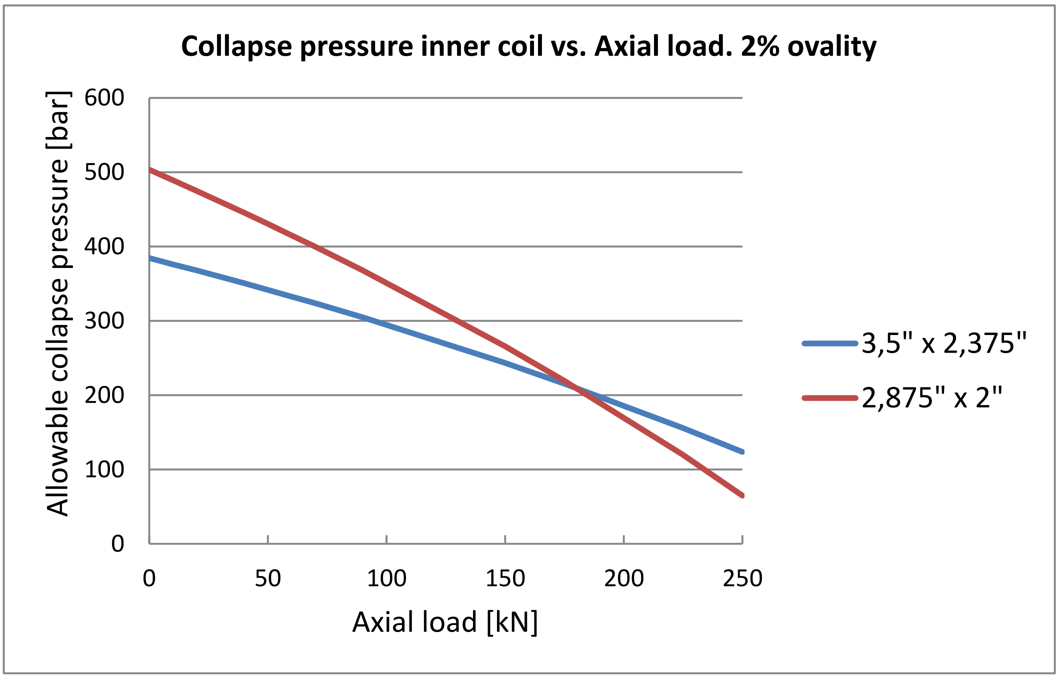


Figure 4-18 Collapse pressure vs. Axial load

Figure 4-18 shows the axial load on the CT string has a big impact on the collapse pressure for the CT string. This needs to be taken into account when designing DualCTD operations. Maximum hook load/injector load for the 3,5" x 2,375" DualCTD concept is calculated in sub section 4.9 to be 364 kN when POOH. This axial load at the injector will give a collapse rating less than 100 bar for the inner CT. The inner string will however not carry all the weight of the system. Axial load distribution between the two CT needs to be further investigated to be able to calculate the correct collapse rating for the inner string.

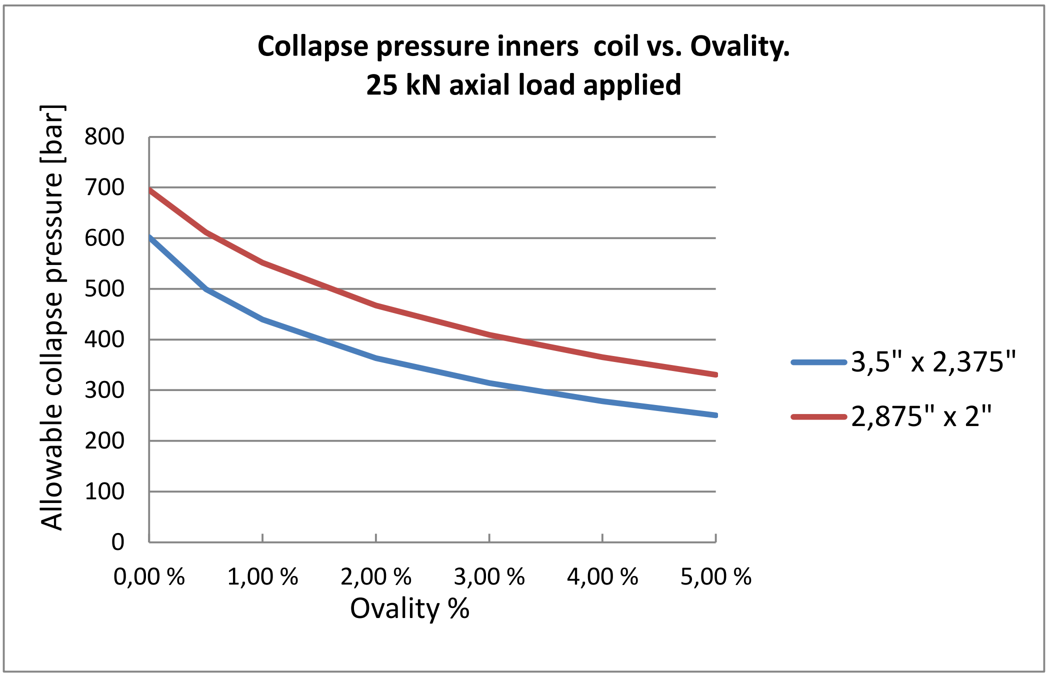


Figure 4-19 Collapse pressure vs. Ovality

No CT strings are perfectly round. An ovality of 2% is from experience said to be an average for CT strings. Figure 4-19 shows that the ovality has a big impact on the collapse rating for the inner string. An ovality of 2% is used in the calculations in this thesis.

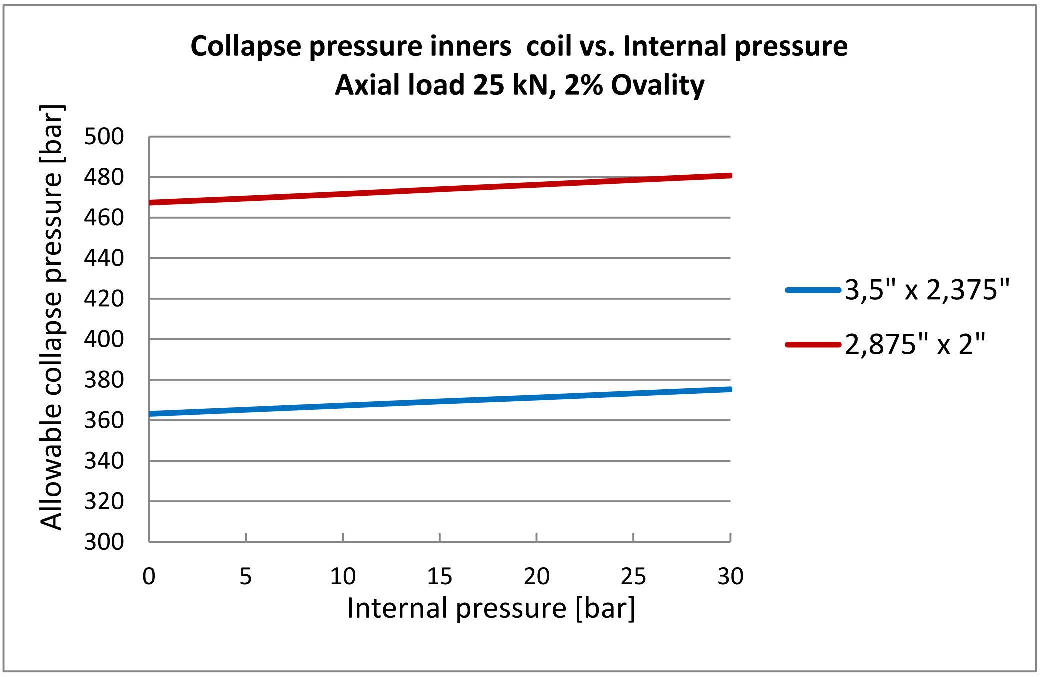


Figure 4-20 Collapse pressure vs. Internal pressure

Figure 4-20 shows that the internal pressure in the inner string will increase the collapse resistance for the CT. This is favorable for collapse calculations at the injector head where there will still be some pressure in the inner string when big axial loadings is applied to the CT when RIH and POOH.

4.11. Fatigue

The large CT diameters used in the DualCTD operations greatly increase the fatigue damage being done to the CT compared to normal CT operations. Fatigue investigations of the DualCTD concept should be performed to get a picture of how long the string will last.

The DualCTD string will be expensive to manufacture and transport. If the string does not last for many operations it may not be economic feasible to perform these kind of operations. Fatigue life of the CT string depends on many factors, including:

- Bending forces downhole when RIH and POOH
- Bending forces at the reel and over the gooseneck
- Stretching of the string when RIH and POOH
- Stretching and heave compensating of the string when run from a floater
- Cyclic pumping and pressure increase
- Cyclic torque while drilling
- Diameter, wall thickness, material of the CT string

4.12. Well Control and Safety Aspects

Well control approach for the DualCTD concept will be much of the same as in CTD. Some important differences need to be examined. These differences are discussed briefly in this subsection.

If the DualCTD operation is run without a riser, a control head, subsea injector and subsea lubricator is required at the seafloor for safe operations and well control.

A larger and customized CTD BOP with following properties is needed:

- The BOP shear rams needs to be able to cut the dual CT string
- The BOP pipe rams needs to be able to hold the weight of the dual CT string
- BOP with kill line for the secondary annulus.
- Designed for the maximum downhole pressure

The circulation system on surface will be a closed system, with a choke valve on the return line. This will improve the overall safety of the operation compared to conventional drilling with an open circulation system. No people are required at the rig floor under the drilling process. The DualCTD system require high pumping pressure to get high enough flow rates for sufficient hole cleaning. Areas with high pressure equipment on surface need to be closed off.

4.12.1. Kick Situations:

The heavy BF fluid in the secondary annulus can be used to kill the well if a kick or an unintentional influx to the wellbore occurs. The BF is weighted for the operation to stay within the pore- and fracture pressure limits at all the time. The secondary annulus is sealed off at seafloor with the bop and control head. The BF supply line can be used to bullhead the well by pumping heavy BF into the secondary annulus while closing off or circulating out the low density fluid through the return line inside the dual CT string. The BF in the secondary annulus is designed for wellbore stability reasons only and will contain lost-circulating material (LCM) to seal off the wellbore. Kill fluid can also be pumped down inside the dual CT string, in the annulus or reversed circulating through the inner string.

The lower circulating volume together with online pressure monitoring will give faster detection of pressure changes and kicks downhole as well as detection of lost circulation.

The DualCTD can be designed with a mechanical seal to separate the fluids downhole. This mechanical seal can be used as a secondary downhole BOP and seal of the active wellbore from the secondary annulus. This downhole mechanical seal should have ports that can be open to circulate the heavy BF into the active circulating drilling fluid if kick occurs.

4.12.2. Stuck Pipe

Stuck pipe can be a big challenge in CTD operations. A weak link/disconnect sub should be installed in the BHA to be able to disconnect and retrieve the dual CT if the BHA get stuck. The inner CT needs also to be facilitated pass-through of wireline cutter (RCT) for recovery of stuck CT. Cutting of the CT at surface is not a preferred solution. It will be very time consuming if the CT string has to be cut in small pieces from surface and recovered one by one. Fishing the string with jointed pipes is possible if the CT string is disconnected from the BHA downhole. The axial load capacity for CT strings does not allow big over-pull to free stuck pipes. Contingency plans needs to be in place if the CT gets stuck.

Statoil had good experiences on Heidrun with pumping of nitrogen to lower the pressure in the well to free differential stuck CT strings. The possibility to circulate nitrogen up the annulus should be use as a contingency to free a differential stuck CT strings in the DualCTD concept. The return conduit inside the dual CT must be closed and nitrogen pumped down and circulated up the secondary annulus.

4.13. Operation management

DualCTD from subsea templates is discussed in this thesis. New wells will be drilled with conventional drilling in the big hole sections, bigger than 8,5”. DualCTD is then used to drill the next section and into the reservoir zone. Drainage holes will be kicked-off with DualCTD from the existing wellbore at the required depth.

Operation procedure:

The DualCTD BOP, control head, injector and lubricator is connected to the subsea template and the string is run into the hole. The old fluid in the well can be circulated out by filling the well with BF through the dual CT string from bottom of the well. The return fluid is routed through the BF supply line at seafloor. A subsea pump may be required on the BF supply line to pump the fluid back to surface. The BF can also be filled through the BF supply line. The viscous BF will then push the old fluid down for it to be circulated back to surface through the dual CT string.

BF will be supplied continuous through the BF supply as the drilling proceeds. The BF column can also be kept stable if the intersection zone between the two fluids needs to be located at one depth all the time. When drilling is done, the whole well has to be changed to the heavier BF to keep the borehole stable. BF can be circulated down the dual CT string and the lighter drilling fluid will be returned through the inner string. BF can also be supply through the BF supply line.

Running of casing and cementing operations need to be investigated further. These operations may have to be conducted using a drill string because of the large handling weight of the casing. The casing will displace fluid while it is run into the hole. This excessive fluid can be pumped back to the rig with a BF subsea pump through the BF supply line.

4.14. Rig Types

One of the main drivers for introducing the DualCTD concept is to be able to drill wells with lower specification drilling rigs, or even from intervention boats. The circulating volume is significantly reduced with the DualCTD concept and less flow rate is required for hole cleaning. However, a rather big volume of BF is needed to fill the secondary annulus that’s created on the outside of the dual CT string.

Drainage holes are usually small diameter and drilled through tubing/casing. The annulus cross section area is not that big and the fluid volume required in the operation is small compared to big hole drilling. The DualCTD concept can be used to drill these kinds of wells from smaller rigs or purpose built intervention rigs/boats. The new and big 5^{th} and 6^{th} generation rigs used today are “over specified” for these kind of operations and much more expensive than lower specified vessels.

4.15. Technical Feasibility Study

A technical feasibility study is developed to look into limitations considering the design of the DualCTD concept. This feasibility study needs to be conducted in the planning stage for every well considered for a DualCTD operation. The feasibility study is performed on two case studies in Chapter 5 to show the applications and advantages of the DualCTD concept.

The following procedure is used to determine whether the DualCTD concept is technically feasible. Calculations for each step are discussed in this chapter.

1. Select hole size, DualCTD coil sizes, BHA, barrier fluid and drilling fluid.
2. Calculated the DualCTD reel weight and size. Can it be transported and hoisted onto the platform? If not, compensating solutions needs to be made.
3. CT forces and stress calculations. Check that minimum acceptable WOB can be provided.
4. Ensure that the pulling and pushing capacity of the injector are sufficient to pull the CT and BHA out of the hole.
5. Hydraulics calculations and optimization. Calculate the pressure drop for the circulating system with the selected flow rate. The pumping pressure has to be lower than the design limits for the CT string.
6. Hole cleaning calculations, determine if the selected drilling fluid and flow rate is able to clean the hole properly at required ROP.
7. Fatigue life calculations for the DualCTD string for the parameters calculated above.

If any of the conditions in the procedure above is not met and results in a failure of any of the parameter in the DualCTD operation, the procedure must be started over again from step one and the selected parameter must be optimized for the DualCTD concept to be feasible.

5. Case studies

Two case studies are conducted in this Chapter for the DualCTD concept to describe its applications and advantages.

5.1. Drilling of Drainage Holes

Drilling of drainage holes from existing wells is done to improve the recovery and extend the life time of a field. Drainage holes can be drilled in dead or in live wells. Live wells with low production rates or live wells with undrained hydrocarbon pockets nearby are good candidates for this type of new wells. The DualCTD concept with its sealed off fluid systems is perfectly suited to be conducted on live wells.

There are a lot of subsea wells on the Norwegian continental shelf. Workover and drilling of new wells from subsea templates require standalone floaters or jack-up platforms. These large vessels have high daily rates and drilling of subsea wells can be very expensive. The DualCTD concept is intended for drilling of drainage holes subsea with lower specification vessels. An example well path for drainage well is presented in Figure 5-1

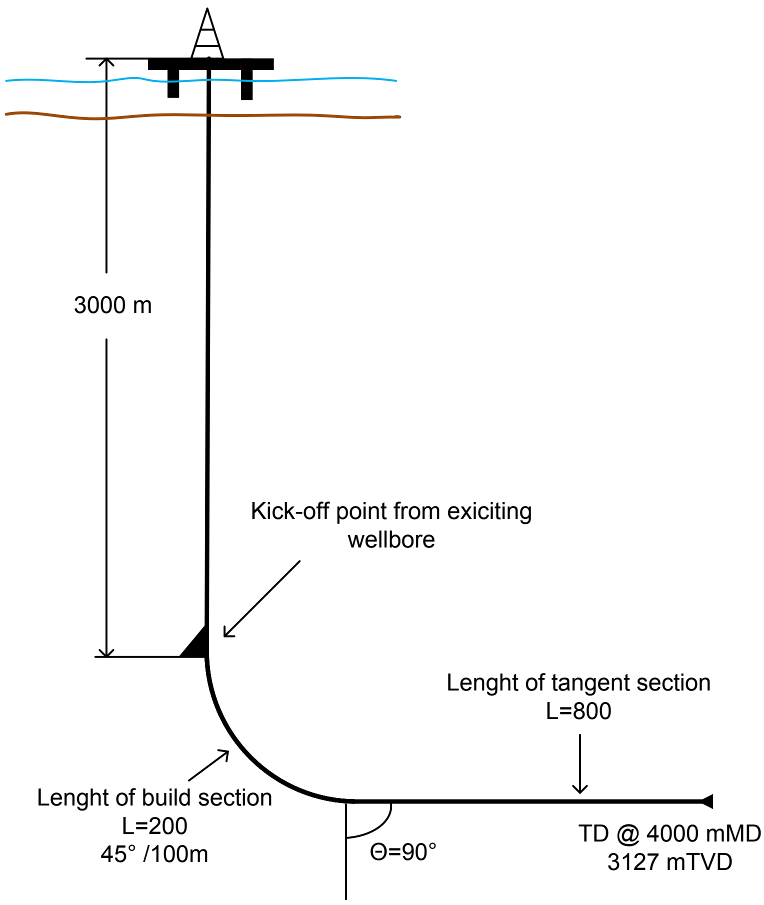


Figure 5-1 Well path for an example drainage well

5.1.1. Results and Discussion

This example well path for a drainage-well is used as an example in the calculations in Chapter 4. Results from these calculations are presented in this sub section.

The different DualCTD string setups used to drill the well are given in Table 4-1and Table 4-2.

Optimized hydraulics for drilling of the drainage well with a 6” bit and two different DualCTD string setups are presented in Table 5-1.

String setup:			3,5” x 2,375”	2,875” x 2"
Flow rate		[l/min]	310	210
Total pressure loss		[bar]	342	434
v, transport		[m/s]	1,9	1,9
Inner coil	Collapse	[bar]	349	439
	Burst	[bar]	689	814
Outer coil	Collapse	[bar]	210	207
	Burst	[bar]	507	508

Table 5-1 Optimized hydraulics for Drainage hole drilling

Flow rates of 310 l/min and 210 l/min for the respective DualCTD setups will be the maximum flow rate for drilling of this subsea well. Collapse pressure of the inner string will be limiting for maximum flow rate in the circulating system.

Corresponding ROP for 2% and 4% CC for the given flow rates are presented in Figure 4-13 and Figure 4-14, and listed in Table 5-2.

DualCTD setup	Flow rate [l/min]	Allowable CC	q-cuttings [m3/s]	**ROP [m/h]**
3.5" x 2,375"	310	2 %	0,00010	**20,4**
	310	4 %	0,00021	**40,8**
2,875" x 2"	210	2 %	0,00007	**13,8**
	210	4 %	0,00014	**27,6**

Table 5-2 ROP Drainage hole drilling

Maximum ROP for the will be 40,8 m/h and 27,6 m/h with respect to cutting transport limitations of 4% CC in the circulating system.

Buckling calculations given in Figure 4-16 show that both DualCTD string setups are able to transmit the required WOB of 13,3 kN in a 6” hole from a 3000 m vertical section kick-off, to the end of the 800 m horizontal section.

The weight of the DualCTD system, given in Table 4-3, is 73tons & 69 tons respectively.

The axial load capacity for the outer string and the maximum injector-/hook load are calculated in Table 4-8. The maximum POOH axial load is 364kN. This is far below the axial load capacity for the outer string that is 783 kN. Axial stress/tension will not be a problem in drilling of this well.

5.1.2. Conclusion of Drainage Hole Drilling with DualCTD

The results show that the DualCTD concept can be used in drilling of drainage holes for subsea wells.

Using the DualCTD to drill drainage holes will provide effective hole cleaning inside the inner string. An optimized and adaptive hydrostatic column with BF in the secondary annulus will provide downhole pressure and formation stabilizing properties, as described in Chapter 4. This makes it possible to drill drainage holes in depleted reservoirs, through formations with abnormal pressure regimes, loss zones and other problematic downhole conditions.

The handling weight of the system and fatigue life of the strings will be the main constraints for the system. However, more research on every part of the operation is needed to bring the concept to a field proven method for drilling of drainage holes.

5.2. Production drilling

Drilling of production wells for the Wisting field in the Barents Sea is investigated in this case study. The Wisting field is a shallow reservoir located 300 m below the seabed. This will require a lot of wells and subsea templates to be able to drain the reservoir in an effective way. The idea is to drill/wash the conductor in place and then drill the next sections and the reservoir section with the DualCTD system.

Drilling with DualCTD from a smaller and custom made vessel will be cheaper than drilling conventionally with today’s big and over specified drilling rigs, which are designed for deep water drilling.

An example well path for drilling of production wells on the Wisting field is presented in Figure 5-2.

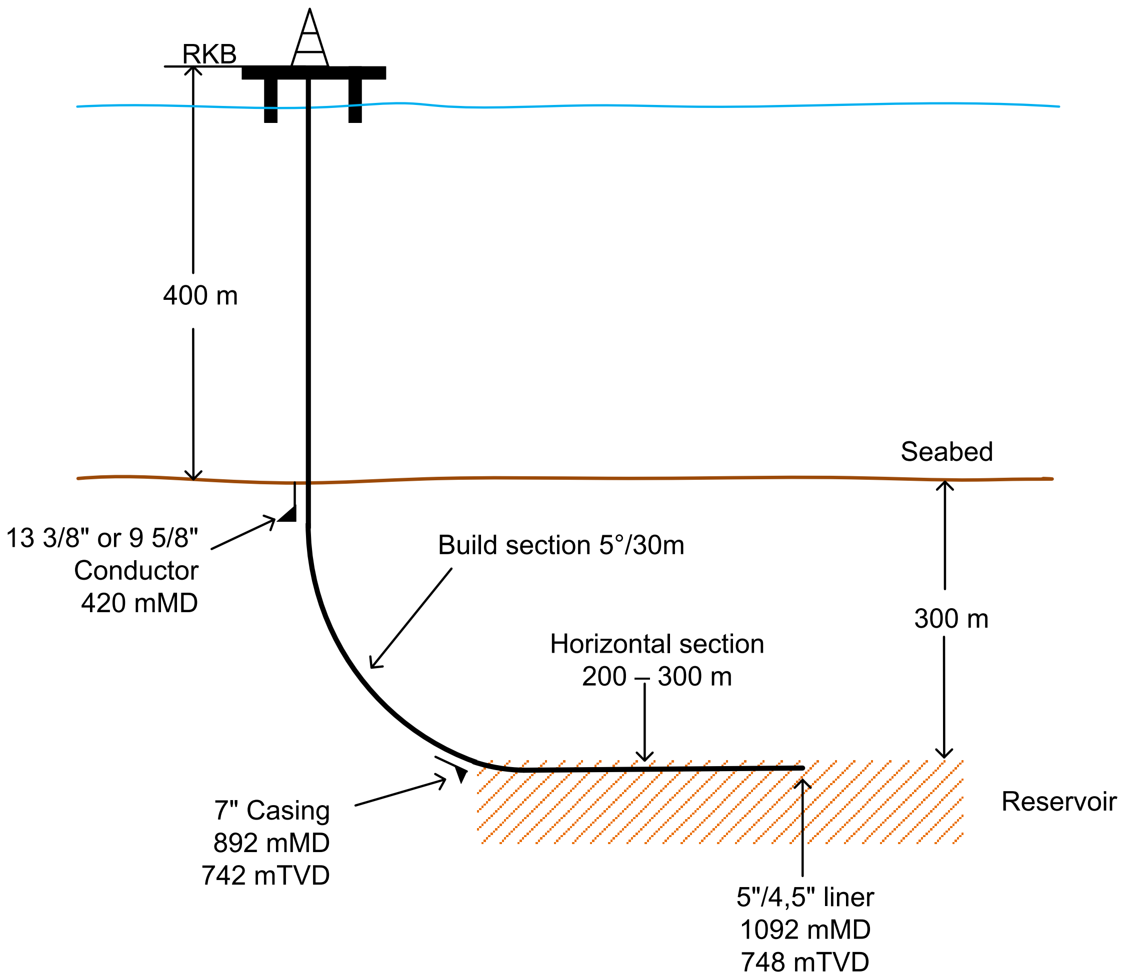


Figure 5-2 Well path for a production well at the Wisting field in the Barents Sea

A 13 3/8" or 9 5/8" conductor will be washed, jetted or sucked down to around 20m below the seabed. The conductor will act as a fundament to stabilize the template in the soft seabed. DualCTD will be used to drill the next section. An 8 ½" (or smaller) hole is kicked off below the conductor shoe. This will be drilled to the top of the reservoir. And a 7" casing will be installed. The 7" casing shoe is set in a safe distance above the reservoir. The reservoir section will be drilled with a 6" bit with the DualCTD concept and a 5" or 4,5" liner can be installed. A 200m-300m long reservoir section will be sufficient drainage length.

5.2.1. Results and Discussion

5.2.1.1. 8 ½" Section

Maximum transmitted bottom load in the vertical section is calculated to examine if sufficient WOB is available for drilling of a 8,5" hole with the DualCTD system: BF density is set to 1,2sg and drilling fluid density to 1sg. String specifications can be found in Table 4-1 and Table 4-2.

Buckling resistance for the strings will increase when a 1,2sg BF and 1sg drilling fluid is used compared to the buckling calculations in Table 4-7 with a 1.7sg BF and 1sg drilling fluid. Helical buckling resistance is given in Table 5-3:

	Coiled tubing			Mud weight		Horizontal	
Case	OD, outer	OD, inner	Weight	DF	BF	F,cr	F,hel
#	[in]	[in]	[N/m]	[kg/m3]		[kN]	[kN]
1	3,5	2,375	107,1	1000	1200	40	74
2	2,875	2	62,0	1000	1200	21	39
3	2,875	NA	34,2	1200	NA	14	26

Table 5-3 Helical buckling resistance Wisting field

Bottom hole loads for the 8,5” section is calculated in Table 5-4:

String setup		3 1/2" & 2 3/8"	2 7/8"x2"	2 7/8” CT
Length of vertical section	[m]	420	420	420
Maximum transmitted bottom load	[kN]	54,7	40,6	23,4
Axial load at the end of build section	[kN]	67	37,2	24

Table 5-4 Maximum transmitted bottom load in vertical section

WOB requirements to drill with a 8,5” bit is 2,2kN/in, this gives a WOB bit of 18,7kN. Table 5-4 shows that all of the string setups in are able to supply enough WOB at the beginning and at the end of the 8,5” section.

Maximum flow rate for the circulation system for the two different DualCTD setups is optimized with the hydraulic model that is developed in this thesis and listed in Table 5-5:

String setup			3,5" x 2,375"	2,875" x 2"
Flow rate		[l/min]	580	460
Total pressure loss		[bar]	347	439
v, transport		[m/s]	4,1	5,0
Inner coil	Collapse	[bar]	349	439
	Burst	[bar]	689	814
Outer coil	Collapse	[bar]	210	207
	Burst	[bar]	507	508

Table 5-5 Maximum flow rate in 8,5" section

Maximum flow rate is 560 l/min and 460 l/min respectively.

Maximum ROP with the maximum flow rates for 2% and 4% cuttings concentration with a 8,5” bit is calculated in Table 5-6.

DualCTD setup	Flow rate	Allowable CC	q-cuttings	ROP
	[l/min]		[m3/s]	[m/h]
3.5" x 2,375"	580	2 %	0,00019	19,0
	580	4 %	0,00039	38,0
2,875" x 2"	460	2 %	0,00015	15,1
	460	4 %	0,00031	30,2

Table 5-6 Maximum ROP for maximum flow rates in 8,5" section

ROP will be low with 2% CC acceptable in the circulation system for the two DualCTD string setups. A 4% CC will give sufficient ROP for both DualCTD strings.

5.2.1.2. 6" Section

Drilling of the 6" section will be conducted with the DualCTD system.

Length of the horizontal section will be limited by the maximum transmitted bottom load in the vertical section, the transferred axial load at the end of the build section and the minimum required WOB.

Maximum horizontal lengths to be drilled for the production wells at the Wisting field for the well path illustrated in Figure 5-2 are calculated in Table 5-7, with a 6" bit, required bit weight of 13,3kN, BF weight of 1,2sg, 1sg drilling fluid, open hole friction factor 0,3 and cased hole friction factor 0,2. Helical buckling in the horizontal section for the strings is taken into account in calculations of the maximum horizontal length that can be drilled.

String setup		3 1/2" x 2 3/8"	2 7/8" x 2"	2 7/8 CT
Length of vertical section	[m]	420	420	420
Maximum transmitted bottom load	[kN]	54,7	40,6	23,4
Axial load at the end of build section	[kN]	67,0	49,6	24,6
Maximum horizontal length to be drilled	[m]	1382	1229	630

Table 5-7 Maximum horizontal length to be drilled in Production wells at Wisting

Table 5-7 shows that the 3,5" x 2,375" DualCTD is able to drill a 1382 m horizontal section, the smaller 2,875" x 2" DualCTD is able to drill 1229 m horizontal. The conventional 2,875" CTD is only able to drill a 630 m long horizontal section.

Pressure loss and cuttings velocity for the well path in the Wisting field are calculated and shown in Table 5-8.

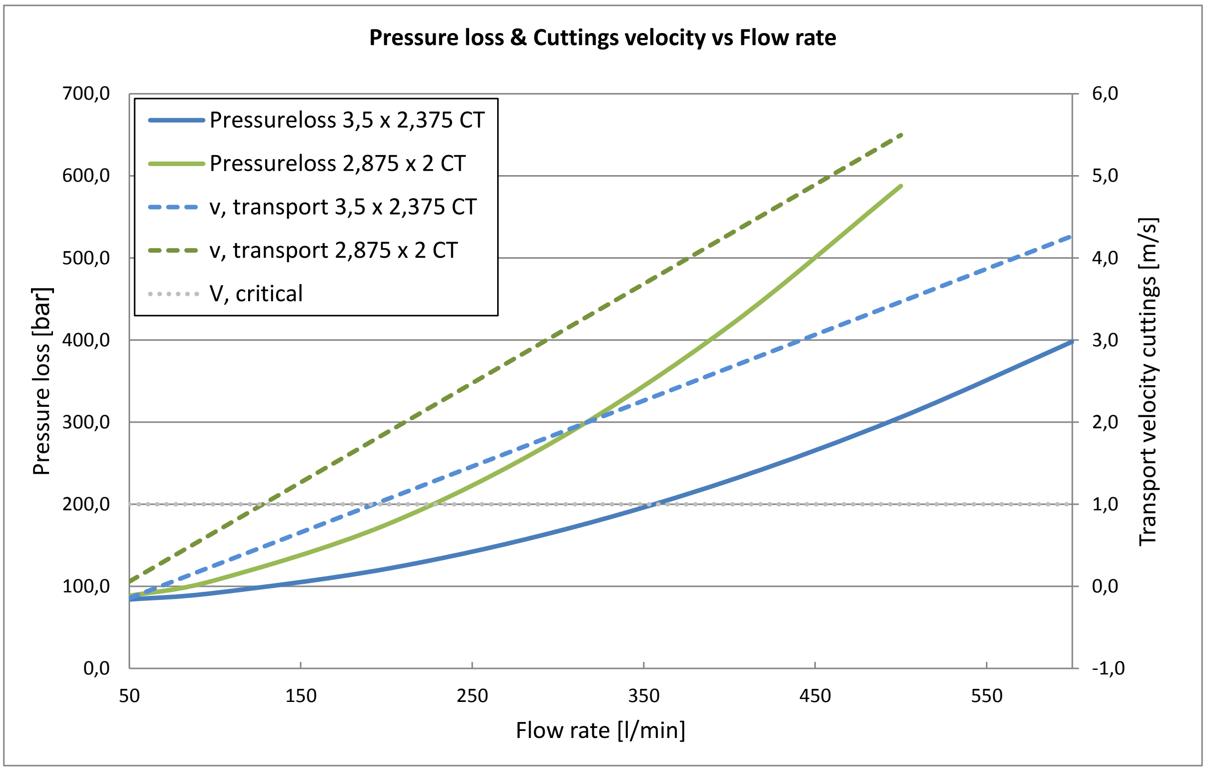


Table 5-8 Pressure loss and cuttings velocities for the Wisting production well

Minimum flow rate is, from Table 5-8, 190 l/min for the 3,5” x 2,375” DualCTD string and 130 l/min for the smaller 2,875” x 2” DualCTD string.

Maximum flow rates are determined by burst and collapse ratings for the string setups. Maximum flow rates with its corresponding friction pressure drop is optimized to stay within the burst and collapse limits for the given string setups and given in Table 5-9

String setup			3,5" x 2,375"	2,875" x 2"
Flow rate		[l/min]	540	405
Total pressure loss		[bar]	341	425
v, transport		[m/s]	3,8	4,3
Inner coil	Collapse	[bar]	349	439
	Burst	[bar]	689	814
Outer coil	Collapse	[bar]	210	207
	Burst	[bar]	507	508

Table 5-9 Maximum flow rate and cutting transport velocities

The maximum flow rates will give very high fluid flow velocities inside the CT strings. This can cause excessive wear of components in the circulating system. The BHA tools, mud motor and bit must also be optimized to work with these flow rates

Maximum ROP with the maximum flow rates for 2% and 4% cuttings concentration with a 6” bit is calculated in Table 5-10

DualCTD setup	Flow rate [l/min]	Allowable CC	q-cuttings [m3/s]	**ROP [m/h]**
3.5" x 2,375"	540	2 %	0,00018	**35,5**
	540	4 %	0,00036	**71,0**
2,875" x 2"	400	2 %	0,00013	**26,3**
	400	4 %	0,00027	**52,6**

Table 5-10 Maximum ROP Wisting field

Maximum ROP is high enough for the drilling operation to proceed in a decent speed for both string setups and for both 2% and 4% cuttings transport. A ROP of up to 71m/h is possible with the 3,5” x 2,375” DualCTD setup. ROP is however, formation, bit, WOB and RPM dependent, and may not be as high as calculated her.

BF and drilling fluid volume for drilling of the 6” section with DualCTD are calculated and given in Table 5-11:

3,5" x 2,375" DualCTD

Circulating volume	Flow area	Length	Circulating volume
	[m2]	[m]	[m3]
Inner coil	0,0021	1092	2,27
outer coil	0,0021	1092	2,28
6" OH-BHA	0,0120	30	0,36
Total			**4,91**
Barrier fluid	Flow area	Length	Volume
	[m2]	[m]	[m3]
7" casing - DualCTD	0,0186	892	16,6
6" OH - DualCTD	0,0120	300	3,6
Total			**20,2**

Table 5-11 Circulating volumes 6" DualCTD at the Wisting field

Circulating drilling fluid volume required is $5m^3$ and BF volume requires is $20m^3$. This is small volumes that can easily be handled by smaller drilling/intervention vessel.

5.2.2. Conclusion for Drilling of Shallow Production Wells with DualCTD

The Wisting production wells can be drilled with the DualCTD System. Sufficient WOB and flow rates are available to drill the 8,5” and 6” sections. Cuttings carrying capacity and the corresponding ROP will be effective at 4% CC.

By using the DualCTD setup, the need of a marine riser will be eliminated and a smaller vessel can be used. Cuttings transport through the inner string will provide sufficient hole cleaning with the given flow rates.

The required volumes of BF and circulating drilling fluid will be small and can easily be handled from a drilling/intervention vessel.

Running of casing and cementing operations need to be examined to investigate if it is possible to perform these operations with the DualCTD string.

6. Conclusion

- The DualCTD concept is very well suited for MPD drilling with its closed circulating system. The concept can be used to drill challenging reservoirs with abnormal pressure regimes, through depleted zones and through loss circulation zones, etc.
- Two flow conduits inside the dual CT string provide a separated circulating system for the drilling fluid. This gives excellent cutting transport and hole cleaning properties from the bottom of the well inside the inner string.
- A barrier fluid (BF) can be located in the secondary annulus between the borehole and the dual CT string. Placing the BF in the secondary annuls below seafloor results in an optimized stabilizing hydrostatic head with formation preserving properties. Longer sections can be drilled with the BF/seawater interference level at the seafloor.
- The drilling fluid will be optimized for hole cleaning properties and cutting transport to surface. As well as provide low frictional pressure loss in the separated circulating system.

- The increased combined unit weight of the DualCTD setup increase the bottom load and available weight on bit (WOB) in vertical wells compared to conventional CTD.
- Buckling resistance is increased with the DualCTD setup due to the combined stiffness of both strings.
- A heavy BF located on the outside and a lighter drilling fluid located on the inside of the dual CT string will reduce the buoyant weight of the dual CT string. This will reduce the drag force and longer horizontal sections can be drilled with the DualCTD setup compared to conventional CTD.

- The DualCTD concept would allow utilizing a lower specification rig or a custom build intervention rig/boat. Assuming the smaller vessels has 25% less day-rates together with faster tripping times will significantly reduce the well cost, compared to conventional drilling.

- The technology and experiences available in the conventional- and coiled tubing drilling industry today should be implemented to establish the DualCTD system.

7. Future Work

- Investigation of manufacturing methods for the big dual CT strings is needed.
- Further study of the handling weight and compensating measures of transporting the DualCTD reel.
- Hydraulic model with cuttings effect on return fluid flow and for other drilling fluid rheology models.
- The DFV and the mud return system needs to be investigated further to find a suitable and reliable solution for the DualCTD concept.
- CT fatigue life prediction model needs to be established.
- Casing installation and cementing methods with the DualCTD system needs to be investigated.
- Well control methods and equipment should be examined
- Significant development work is needed to bring the DualCTD to a field proven method

8. Nomenclature and Abbreviations

8.1. Abbreviations

BF	Barrier Fluid
BHA	Bottom Hole Assembly
BHP	Bottom Hole Pressure
BOP	Blow Out Preventer
CC	Cuttings Concentration
CCT	Concentric Coiled Tubing
CCTVT	Concentric Coiled Tubing Vacuum Technology
CT	Coiled Tubing
CTD	Coiled Tubing Drilling
CWD	Casing While Drilling
DCS	Dual Circulation System
DDS	Dual Drill String
DF	Drilling Fluid
DGDS	Dual Gradient Drilling System
DualCTD	Dual Coiled Tubing Drilling
ECD	Equivalent Circulation Density
ERD	Extended Reach Drilling
HOL	Heavy Over Light
LWD	Logging While Drilling
MWD	Measurement While Drilling
NPT	Non Productive Time
OBM	Oil Based Mud
PMCD	Pressurized Mud Cap Drilling
PMCD	Pressurized Mud Cap Drilling
POOH	Pull Out Of Hole
RDM	Reelwell Drilling Method

RIH	Run In Hole
ROP	Rate of Penetration
RPM	Rotations Per Minute
RSS	Rotating Steerable Systems
sg	Specific Gravity
UBO	Under Balance Operations
WBM	Water Based Mud

8.2. Nomenclature

C_{drag}	Drag coefficient
$F_{b,max}$	Maximum transmitted bottom load in vertical wellbores [N]
F_{eoc}	Axial load at end of build section [N]
F_{kop}	Axial load at kick off point [N]
P_i	Applied internal pressure [psi]
Q_y	Tensile load capacity [lb]
$c_{cuttings}$	CC [%]
d_{BHA}	Diameter BHA [m]
d_{i1}	Inner CT inner diameter [m]
d_{i2}	Outer CT inner diameter [m]
d_{o1}	Inner CT outer diameter [m]
$q_{cuttings}$	Cuttings volume rate at given ROP and bit diameter [m^3/h]
$q_{flow\ rate\ fluid}$	Flow rate drilling fluid [m^3/h]
r_0	Radius of CT string [m]
r_i	Inside radius pipe[m]
r_o	Outside radius pipe [m]
v_{fluid}	Fluid velocity [m/s]
v_{slip}	Cuttings slip velocity [m/s]
$v_{transport}$	Cuttings transport velocity [m/s]

$\bar{\theta}$	Average inclination over the element [degree]
$\rho_{drilling\ fluid}$	Drilling fluid density [kg/m^3]
ρ_i	Density inside fluid [kg/m3]
ρ_o	Density outside fluid [kg/m3]
ρ_p	Density cuttings [kg/m^3]
ρ_{steel}	Density of steel, [7850 kg/m^3]
σ_y	Yield strength [psi]
Δ	Roughness of the open hole. [mm]
ΔP	Difference in pressure, due to friction when circulation [Pa]
$\Delta\theta$	change in azimuth direction [radians]
d_{bit}	Diameter of bit [m]
E	Young's modulus for steel = $211*10^9$ N/m^2
F	Fanning friction factor
F_0	Axial compressive load at the calculation starting point [N]
F_1	Force at the previous element (N)
F_2	Force at the end of the element (N)
g	Gravitational constant, [9,81 m/s^2]
h	True vertical depth [m]
I	Moment of Inertia [m^4]
L	Length of CT string [m]
n	Number of strings
N	Normal force on the element [N]
N_{re}	Reynolds number
ODmax	Section major diameter, measured [in]
ODmin	Section minor diameter, measure [in]
P	Pressure [Pa]
P_B	Internal yield or burst pressure [psi]
P_{mud}	Static pressure from the mud [Pa]
PV	Dynamic viscosity of the fluid [Pa*s]

r	Distance between the CT wall and the borehole wall [m]
R	Radius of curved section [m]
ROP	Rate of penetration [m/hour]
TVD	True Vertical Depth, mud level to lowest point in the well [m]
$T_{wall\text{-}min}$	Thinnest wall [in]
W	unit weight of pipe, submerged [N/m]
x	Coordinate along the horizontal axis, measured from the lower end [m]
ID	Inner diameter pipe [m]
OD	Outer diameter pipe [m]
OD	Outer diameter of CT [m]
OH	Diameter open hole [m]
$Pratio$	Poisson's ratio
Q	Applied axial force [lb]
R	Radius of CT reel [m]
UF	CT utilization factor, UF=0 for new CT, UF=1 for fully worn CT
θ	Inclination [degrees]
μ	Friction factor borehole wall/casing
φ	Absolute roughness of the CT [mm]

8.3. SI Metric Conversation Factors

1 psi	=	6894,75	[Pa]
1 Pa	=	1,00E-05	[bar]
1 in	=	0,0254	[m]
1 ft	=	0,3048	[m]
1 lbm	=	0,4536	[kg]
1 lbf	=	4,448	[N]

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APPENDIX

Appendix I CT Mud Motors

Metric

Size (Inch)	Size (mm)	Configuration	Flow Rates (lpm)	Speed Ratio (Rev/l)	Bit Speed (rpm)	Maximum Torque (N·m)	Stall Torque (N·m)	Maximum Differential (kPa)
1 3/4	44	5:6 4 Stage	75 - 150	5.17	390 - 780	110	180	4140
2 1/16	52	4:5 2 Stage Air	189 – 302	1.72	325 - 520	170	280	2070
2 1/8	54	5:6 2.5 Stage	114 – 230	1.75	200 - 400	270	310	3450
2 3/8	60	4:5 6 Stage	76 – 190	5.26	400-1000	163	325	6210
2 3/8	60	7:8 4 Stage	151 – 300	1.42	215 - 430	400	640	4140
2 7/8	73	5:6 3 Stage	95 – 379	1.12	106 - 425	380	720	3100
2 7/8	73	7:8 2 Stage Air	260 – 490	0.57	150 - 280	490	740	2070
2 7/8	73	7:8 3 Stage	190 – 380	0.71	135 - 270	600	940	3100
3 1/8	79	7:8 4 Stage	189 – 415	0.94	178 - 390	610	920	4830
3 1/2	89	5:6 3 Stage	284 – 570	0.66	187 – 375	645	1355	3100
3 1/2	89	7:8 2 Stage Air	380 – 660	0.44	160 – 280	680	1150	2070
3 1/2	89	7:8 3 Stage	285 – 570	0.63	180 – 360	680	1300	3100
3 1/2	89	7:8 3.8 Stage	285 – 570	0.41	118 - 235	1495	2240	4585

Table - I-I CT Mud motor specifications from Wenzel Downhole Tools Ltd.

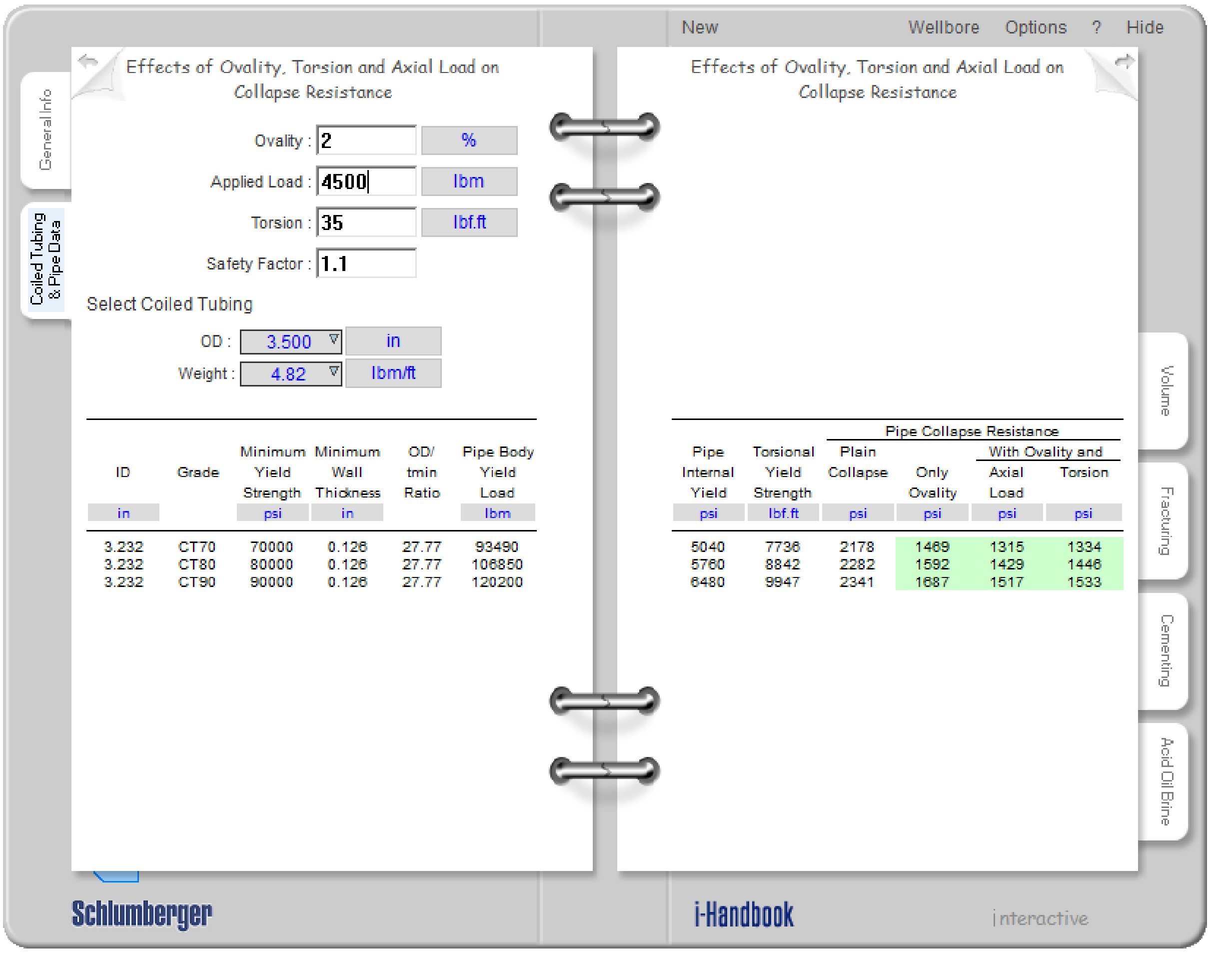
Appendix II Schlumberger's I-Handbook

Mechanical Properties of API Coiled Tubing

OD (in)	Weight (lbm/ft)	ID (in)	Grade	Wall Thickness Specified t (in)	Wall Thickness Minimum t-min (in)	Hydro Test Pressure (psi)	OD/t-min Ratio	Pipe Collapse Resist. (psi)	Pipe Body Yield Load (lbm)	Pipe Internal Yield Pressure (psi)	Torsional Yield Strength (lbf.ft)
2.000	3.41	1.650	CT80	0.175	0.167	10000	11.98	12241	76930	13360	3245
2.000	3.41	1.650	CT90	0.175	0.167	10000	11.98	13771	86550	5030	3651
2.000	3.64	1.624	CT70	0.188	0.180	10000	11.11	11467	72040	12600	2990
2.000	3.64	1.624	CT80	0.188	0.180	10000	11.11	13105	82340	14400	3417
2.000	3.64	1.624	CT90	0.188	0.180	10000	11.11	14743	92630	16200	3844
2.375	2.64	2.157	CT70	0.109	0.104	4900	22.84	3333	51940	6130	2831
2.375	2.64	2.157	CT80	0.109	0.104	5600	22.84	3526	59360	7010	3236
2.375	2.64	2.157	CT90	0.109	0.104	6300	22.84	3754	66780	7880	3640
2.375	3.00	2.125	CT70	0.125	0.117	5500	20.30	4497	58100	6900	3181
2.375	3.00	2.125	CT80	0.125	0.117	6800	20.30	5742	71220	8490	3853
2.375	3.00	2.125	CT90	0.125	0.117	7100	20.30	5054	74700	8870	4090
2.375	3.20	2.107	CT90	0.134	0.126	7600	18.85	6114	80120	11220	4334
2.375	3.21	2.107	CT70	0.134	0.126	5900	18.85	5303	62320	7430	3371
2.375	3.21	2.107	CT80	0.134	0.126	6300	18.85	4811	66400	7880	3635
2.375	3.70	2.063	CT70	0.156	0.148	7000	16.05	7270	72480	8720	4177
2.375	3.70	2.063	CT80	0.156	0.148	8000	16.05	8016	82840	9970	4360
2.375	3.70	2.063	CT90	0.156	0.148	9000	16.05	8701	93190	9550	4905
2.375	4.11	2.025	CT70	0.175	0.167	7900	14.22	8975	81090	9840	3815
2.375	4.11	2.025	CT80	0.175	0.167	9000	14.22	9986	92670	11250	4773
2.375	4.11	2.025	CT90	0.175	0.167	10000	14.22	10942	104260	12660	5370
2.375	4.39	1.999	CT70	0.188	0.180	8500	13.19	9809	86890	10610	4413
2.375	4.39	1.999	CT80	0.188	0.180	9700	13.19	11211	99300	12130	5043
2.375	4.39	1.999	CT90	0.188	0.180	10000	13.19	12477	11710	13640	5673
2.875	3.67	2.625	CT70	0.125	0.117	4600	24.57	2831	70960	5700	4793
2.875	3.67	2.625	CT80	0.125	0.117	5200	24.57	3033	81100	6510	5478
2.875	3.67	2.625	CT90	0.125	0.117	5900	24.57	3194	91240	7330	6163
2.875	3.92	2.607	CT70	0.134	0.126	4900	22.82	3341	76170	6140	5090

Schlumberger i-Handbook informative

Figure - II-I Mechanical properties of API Coiled Tubing



ID (in)	Grade	Minimum Yield Strength (psi)	Minimum Wall Thickness (in)	OD/ tmin Ratio	Pipe Body Yield Load (lbm)
3.232	CT70	70000	0.126	27.77	93490
3.232	CT80	80000	0.126	27.77	106850
3.232	CT90	90000	0.126	27.77	120200

Pipe Internal Yield (psi)	Torsional Yield Strength (lbf.ft)	Pipe Collapse Resistance: Plain Collapse (psi)	Only Ovality (psi)	With Ovality and Axial Load (psi)	With Ovality and Torsion (psi)
5040	7736	2178	1469	1315	1334
5760	8842	2282	1592	1429	1446
6480	9947	2341	1687	1517	1533

Figure - II-II Effects of Ovality, Torsion and Axial Load on Collapse Resistance

Appendix III Frictional Drag Calculations

Drag model for a straight borehole (S. Sangesland 2014):

$$F_2 = F_1 + w(cos\theta +/- \mu sin\theta) \qquad \textit{Eq - III-I}$$

Plus sign for pulling the string and minus sign for lowering the string. Where:

- F_2 = Force at the end of the element [N]
- F_1 = Force at the previous element [N]
- W = unit weight of pipe, submerged [N/m]
- μ = friction factor
- θ = Inclination [degrees]

Discreet drag model for a curved borehole (S. Sangesland 2014):

$$F_2 = F_1 + w_{curve} * \cos\bar{\theta} +/- \mu * |N|) \qquad \textit{Eq - III-II}$$

$$N = \sqrt{(F_1 * \Delta\emptyset * \sin\bar{\theta}) + (w * \sin\bar{\theta} + F_1\Delta\theta)\ ^2} \qquad \textit{Eq - III-III}$$

$$For\ \Delta\emptyset = 0, no\ change\ in\ azimut\ direction,$$

$$N = w * \sin\bar{\theta} + F_1 * \Delta\theta \qquad \textit{Eq - III-IV}$$

$$\Delta\theta = \theta_2 - \theta_1\ (radians) \qquad \textit{Eq - III-V}$$

$$\Delta\emptyset = \emptyset_2 - \emptyset_1\ (radians) \qquad \textit{Eq - III-VI}$$

Plus sign for pulling the string and minus sign for lowering the string. Where:

- $\bar{\theta}$ = average inclination over the element [degree]
- N = Normal force on the element [N]
- $\Delta\emptyset$ = change in inclination [radians]

"A negative value for N means that the normal force is reduced since F will tend to lift the drill string off the low side of the well in the build-up section when POOH (S. Sangesland 2014)."

Appendix IV Burst Pressure of the CT

Maximum internal yield pressure, burst rating of the CT, is the maximum internal pressure the CT can be exposed to, is calculated as follows (King 2009):

$$P_B = \frac{2 * t_{min} * \sigma_y}{OD} \qquad \textit{Eq - IV-I}$$

Yield internal pressure capacity

$$P_y = \frac{\sigma_y}{\sqrt{4M^2 - 2M + 1}} \qquad \textit{Eq - IV-II}$$

CT material constant, M:

$$M = \frac{\alpha^2}{(4 * (\alpha - 1)} \qquad \textit{Eq - IV-III}$$

CT ratio:

$$\alpha = \frac{OD}{t_{min}} \qquad \textit{Eq - IV-IV}$$

Where

- P_B = internal yield or burst pressure [psi]
- t_{min} = thinnest wall [in]

The burst pressure of the CT depends on more factors than just the metallurgy calculations above. Other factors than can affect the burst pressure are: CT size, CT wall thickness, CT strength, damage (dents, corrosion, ovality, and fatigue), offsetting pressure (it is the differential pressure that counts), and mechanical loads (compression/tension) (King 2009).

Appendix V Collapse of CT

The CT is subjected to collapse if the external pressure exceeds the internal pressure. CT strings are not totally round, the ovality of the strings needs to be taken into account for correct collapse pressure calculations.

The collapse pressure of the CT string in the absence of axial stress, internal pressure, ovality and the condition of the tubing is calculated with the equations listed in this chapter. The equations are from the paper by (Jet Reasearch Center 2015). Modified from API Technical Report 5C3.

Collapse pressure for oval CT with internal pressure & axial load:

$$P_{C,Ov,SF} = SF * (g - \sqrt{g^2 - f}) \qquad \textit{Eq - V-I}$$

Faktor, f:

$$f = \frac{\sigma_y K_y P_{ce}}{2M} \qquad \textit{Eq - V-II}$$

Faktor, g:

$$g = \frac{\sigma_y K_y}{4M} + (2 + 3O_v \alpha) \frac{P_{ce}}{4} \qquad \textit{Eq - V-III}$$

Collapse pressure for round CT with internal pressure & axial load:

$$P_C = (P_{yo}^{-2} + P_{ce}^{-2})^{-0,5} \qquad \textit{Eq - V-IV}$$

Yield external pressure capacity:

$$P_{yo} = \frac{\sigma_y K_y}{2 * M} \qquad \textit{Eq - V-V}$$

Elastic collapse pressure for round CT when internal pressure is applied:

$$P_{ce} = 0,7125(\frac{C}{\alpha(\alpha - 1)^2}) \qquad \textit{Eq - V-VI}$$

Yield correction factor:

$$K = \frac{2MP_i}{\sigma_y} - 0,5 * \left(\frac{Q}{Q_y} + \frac{P_i}{\sigma_y}\right) + \sqrt{1 - \frac{3}{4}(\frac{Q}{Q_y} + \frac{P_i}{\sigma_y})^2} \qquad \textit{Eq - V-VII}$$

Ovality index:

$$Ov = \frac{OD_{max} - OD_{min}}{OD} \qquad \textit{Eq - V-VIII}$$

Material constant, C:

$$C = \frac{2E}{q - Pratio^2} \qquad \textit{Eq - V-IX}$$

Safety factor:

$$SF = 0{,}8 * 0{,}8^{UF^{1,5}} \qquad \textit{Eq - V-X}$$

Where:

- ODmax = section major diameter, measured [in]
- ODmin = section minor diameter, measure [in]
- σ_y = CT yield strength [psi]
- $Pratio$ = poisson's ratio
- Q_y = Tensile load capacity [lb]
- Q = Applied axial force [lb]
- P_i = Applied internal pressure [psi]
- UF = CT utilization factor, UF=0 for new CT, UF=1 for fully worn CT

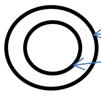
Appendix VI Hydraulic Model

Hydraulic Program for Calculation of Pressure Loss in DualCTD

Håkon Sandven
June, 2015

Dual CTD	Input
Hydraulic	Output

3,5" x 2,375"			
Flow rate		200	[l/min]
Total pressure loss		195,8	[bar]
v, transport		1,1	[m/s]
Inner coil	Collapse	349	[bar]
	Burst	689	[bar]
Outer coil	Collapse	210	[bar]
	Burst	507	[bar]



CT OD:
3 1/2 [in]
2 3/8 [in]

Conversion factors:		
1Pa	1,00E-05	[bar]
1psi	6894,75	[Pa]
1in	0,0254	[m]

Pressure loss	Reel supply	CT supply	BHA	Motor	Bit	OH-BHA	CT return	Reel return	Total
[bar]	4,6	81,0	20	31	30	2,3	25,3	1,5	195,8

INPUTS

3 1/2" & 2 3/8"	OD	ID	Weight	Wall thickness Nom.	Wall thickness Min.	Grade	Pipe collapse	Pipe body yield load	Pipe Internal	Torsional Yield
	[in]	[in]	[lbm/ft]	[in]	[in]		[psi]	[lbm]	[psi]	[lb.ft]
Inner pipe	2,375	2,025	4,11	0,175	0,167	CT90	5054	74700	8870	4090
Outer pipe	3,375	3,124	6,65	0,188	0,18	CT91	5664	168970	8590	13316

Fluid properties	Density	dynamic viscocity
Fluid @ 25 C	[kg/m3]	[Pa*s]
Water	1000	0,0010

Hole specification:

	Measured depth	End Inclination	TVD of section	Build section	Radius	TVD
Section	[mMD]	degrees	[mTVD]	[m]	[m]	[m]
CT on reel	200			200	127	127
Straight hole	3000	0	3000			
Build section	200	90	127,3			
Tangent section	800	90	0			
Total lenght	4000		3127			

Open hole

Open hole roug	0,00025	[m]
Hole OD	6	[in]
	0,1524	[m]

BHA

Lenght	30	[m]
OD	3,5	[in]
	0,0889	[m]

CT reel

diameter	4	[m]
CT	0,089	[m]
CR	0,022225	
Roughness stee	0,04725	mm
Relative	0,000918635	

PRESSURE LOSS CALCULATIONS

Flow area	Pipe-in-pipe [m2]	Pipe [m2]
Return (inner)	0,0021	0,0021
Supply (outer)	0,0021	0,0049

Average Annular bulk fluid velocity:

Flow	[l/min]	200
Return (inner)	[m/s]	1,60
Supply (outer)	[m/s]	1,60
Open hole	[m/s]	1,05

Reynolds number

Return (inner)	#	82 104
Supply (outer)	#	30 368
Open hole	#	66 504

$$\Delta P_{total} = \Delta P_{surface} + \Delta P_{CTreel} + \Delta P_{CTsupply} + \Delta P_{BHA} + \Delta P_{motor} + \Delta P_{bit} + \Delta P_{CTreturn} + \Delta P_{CTreel}$$

CT reel, annular supply

Pressure loss

$$\Delta P_a = \frac{2fL\rho v^2}{d_{i2} - d_{o1}}$$

Fanning friction annular pipe flow

$$f_{CL} = f_{sl} + 0{,}0075\sqrt{\frac{d}{D}}$$

Fan	0,008544374	
Pa	462346,3967	Pa
	4,6	**bar**

Supply CT, annular

Pressure loss

$$\Delta P_a = \frac{2fL\rho v^2}{d_{i2} - d_{o1}}$$

Fanning friction Annulus Supply flowfactor smooth pipes

$$f_{An} = \frac{0{,}059}{N_{re}^{0{,}2}}$$

Fan	0,007488035	
Pa	8103732	Pa
	81,0	**bar**

Pressure loss OH over BHA

Pressure loss:

$$\Delta P_a = \frac{2fL\rho v^2}{d_{i2} - d_{o1}}$$

Fannig friction factor open hole

$$f_{An} = \frac{1}{4}\left[\ln\left[\frac{\Delta}{3{,}715(d_{OH} - d_{BHA})} + \frac{6{,}943}{N_{re}}^{0{,}9}\right]\right]^{-2}$$

Fan	0,0057	
Pa	234428	Pa
	2,3	**Bar**

Return flow inner pipe

Pressure loss

$$\Delta P_i = \frac{2fL\rho v^2}{d_{i1}}$$

Fanning friction factor

$$f_{SCL} = \frac{0{,}0791}{N_{re}^{0{,}25}}$$

Density increas	30	kg/m3
Density:	1030	

Fan	0,006137326	
Pa	2530407,224	Pa
	25,3	**bar**

CT reel, return inner pipe

Pressure loss

$$\Delta P_i = \frac{2fL\rho v^2}{d_{i1}}$$

Fanning friction annular pipe flow

$$f_{CL} = f_{sl} + 0{,}0075\sqrt{\frac{d}{D}}$$

Fan	0,00725543	
Pa	145214	Pa
	1,5	**bar**

SETTLING VELOCITY CALCULATIONS

$$v_{transport} = v_{fluid} - v_{slip}$$

$$v_{slip} = \sqrt{\frac{4g(\rho_p - \rho_{mud})d_p}{3C_{drag}\rho_{mud}}}$$

Turbulent flow, newton's law

Cdrag	0,44

Inermediate flow

$$C_{drag} = \frac{18}{RE^{0,5}}$$

RE	82 104
C	0,062818922

rho,p	3000	kg/m3
rho,mud	1000	kg/m3
d,p	0,005	m
v,fluid	1,60	m/s
v,slip	0,55	m/s
v, transport	1,06	m/s

BURST AND COLLAPSE CALCULATIONS

P,collapse

	2,375"	3,5"	
E	30000000	30000000	psi
u	0,3	0,3	
UF	0,1	0,1	
Pi	290	290	psi
	20	20	bar
Q	11236	11236	lb
	50	50	kN
Ov	2,00 %	2,00 %	

C	65934066	65934066	psi
SF	1	1	
a	14	19	
M	4	5	
K	1	1	

Pce	19103	7308	psi
Pyo	10469	8543	psi
Pc	9181	5554	psi
g	18861	10057	
f	199996258	62436798	
Pco	6381	3835	psi

	5069	3047	psi
Psf	349	210	bar

P,burst

	2,375"	3,5"	
DD	2,375	3,5	in
tt	0,167	0,18	in
YS	90000	90000	psi
a	14,222	19,444	in
M	3,824	5,125	
SF	0,8	0,8	
	0	0	
	9999	7356	psi
P, burst	689	507	bar