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MASTERS'S THESIS

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ABSTRACT

The decisions made during well planning have mainly been focused on safety, cost efficiency and applicability of the design. As the climate have been getting more attention the past years, environment is now high up on the agenda for both the society and authorities. Therefore, the oil industry needs to think of new solutions in order focus more on sustainability and environment.

The Toutatis exploration well was drilled in 2019, close to Lofoten, an environmental sensitive area. It was recognized by a clear environmental profile, which influenced the decision making processes within the whole project. One of the main outcomes from the Toutatis campaign, was that spending more time and workhours in the planning and well design phase can be beneficial. With respect to both the economical side, risk picture and environment. Extra days spent on evaluating operational options, can in some cases be justified by the operational and environmental savings from better suited systems.

The WH and conductor system are known as the 'weak link' in the well design. Choosing the CAN- ductor system from Neodrill as a well foundation provided less or no risk of fatigue issues. The construction can be installed and retrieved with light vessel before the rig arrives on location, cutting both rig time, cost, fuel consumption and the environmental impact. The report from Asplan Viak showed that the main environmental, risk and cost benefits came from reduced rig time and casing material. In total, the rig time was four days shorter for the CAN-ductor compared to that of the conventional technology.

A study showed that it also could be favourable to use DP in shallower waters for exploration wells, with an operation time up to 100 days. Based on weather conditions in September and for the drilling rig West Hercules. Beforehand it had been assumed that it would be more cost effective to select the anchor handling system for an exploration well.

Changing even the small details in an operation, can have a major impact. As for example the Dopeless casings from Tenaris, eliminating the need for greasing the casing joints. Hence lowering the total casing costs with up to 10%, and at the same time reduce the human risk and environmental impact. Another briefly mentioned potential is reuse of equipment. The can used for the Toutatis well had previously been run on another well. Followed by inspections and new painting. Resulting in lower use of resources such as workhours, manpower and materials.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

NOMENCLATURE

List of Symbols

in	inch
m	meter
m^3	cubic meter
ft	feet

List of Abbreviations

AfC	Application for Consent
AfD	Application for Discharge
AFE	Approval For Expenditure
ALARP	As Low As Reasonable Practicable
BHA	Bottom Hole Assembly
CO_2	Carbon dioxide
D&W	Drilling & Wells
BOP	Blow out preventer
DP	Drill Pipe
DOP	Detailed Operational Procedures
ECD	Equivalent Circulating Density
FIT	Formation Integrity Test
WH	Well Head
HPWH	High Pressure Well Head
HSE	Health, Safety & Environment
HSEQ	Health, Safety, Environment and Quality
LCM	Lost Circulation Material
MD	Measured Depth
MSL	Mean Sea Level

MW	Mud Weight
MWD	Measurement While Drilling
NCS	Norwegian Continental Shelf
NGO	None- Governmental Organization
NOFO	Norsk Oljevernforening for Operatørselskap (Norwegian Clean Seas Association for Operating Companies)
NORSOK	Norsk Sokkel's konkurranseutvalg (the Norwegian Shelf's Competitive Position)
NOx	Nitrogen Oxides
NPD	Norwegian Petroleum Directorate
NPT	None Production Time
OBM	Oil Based Mud
POOH	Pull Out Of Hole
PSA	Petroleum Safety Authority
RIH	Run In Hole
RKB	Rotary Kelly Bushing
ROP	Rate Of Penetration
ROV	Remote Operated Vehicles
RPM	Rounds Per Minute
SAR	Search And Rescue
SG	Specific Gravity
SJA	Safe Job Analysis
SOx	Sulphur Oxides
SW	Sea Water
TD	Total Depth
TH	Tubing Hanger
TOC	Top of Cement

TVD	True Vertical Depth
WBM	Water Based Mud
WOW	Wait On Weather
XT	Christmas Tree

1 INTRODUCTION

1.1 BACKGROUND AND OBJECTIVE

Fluctuating oil prices has pushed the oil industry towards making new discoveries in a more cost effective way. Even though downturns are common in this industry, one has not seen peak oil prices since 2013. As this thesis is being made, the world is facing the COVID-19 pandemic, affecting the world as a whole. Just after the oil industry started to heal from the downfall in 2014. We are once again faced with decreasing oil prices, insecurity in the marked and major changes in the daily life as we once knew it. In Norway tax regulations made during the summer of 2020 menced to encourage investments and projects developments on the NCS (Norwegian Continental Shelf).

When used right, nature is one of the most valuable assets we have. Never before has the environment and carbon footprint been such a large part of the media picture. With an increased focus on climate and environment, both the society and authorities are demanding us to think of new ways. Making a need for the oil industry to focus more on sustainability and environment.

On the NCS alone, numbers from NPD shows that as many as 57 exploration wells was drilled or started on in 2019. Slightly above the numbers from 2018[4]. Which provides a large potential for implementing new technology and systems to lower the environmental impact. Therefore, the scope of this master thesis will be on exploration wells, and different approaches towards a safer, less expensive and more environemtnal friendly process.

1.2 STRUCTURE OF THESIS

The thesis built on comparisons between different options in previous reports, in addition to the decisions made for the Toutatis well.

The thesis is divided into the following main chapters:

- **Chapter 2** provides an intro to well planning and well design, and summarizes the whole process. Focusing mainly on the stages and design options for an exploration well.
- **Chapter 3** looks into the traditional top hole system, and compares it to a more modern solution. Includes a case study comparing the environmental footprint from the different options. Conductor VS. CAN- Ductor (report from Neodrill).
- **Chapter 4** evaluates the environmental impact and cost from selecting different station keepen systems on a floating drilling rig. Includes a case study based on the Toutatis project. Anchor & Poostmoor system VS. Dynamic Positioning system (DP) for station keeping (environmental impact and cost)
- **Chapter 6** is a more detailed summary of the Toutatis campaign. Including operational results and the extra measures made to lower the environmental footprint.
- The main results from Chapter 3, 4 and 7 are elaborated at the end of each chapter, and summarized together with the briefer topics in **Chapter 7 Conclusion.**

Other measures that are briefly described:

- Available equipment and reuse (CAN- Ductor)
- **Chapter 5** Greener rigs (West Hercules, West Mira as a hybrid)

2 WELL PLANNING & WELL DESIGN

2.1 INTRO

We are able to drill faster, longer and more complex holes than ever before. New equipment and technology enable us to find more remote reservoirs, and even access them. In addition the industry is able to maintain a sustainable economy with lower oil prices. Regardless, the productivity on the NCS is estimated to decline over the next years. Drilling exploration wells to evaluate new potential reservoirs and their production capability, is therefore crucial to maintain the productivity. However, when the wells become more difficult to drill, it needs to be put more emphasis on the well design process. The wells are in general designed for easy implementation and to ensure well integrity. More challenging wells arises more unforeseen abnormal events. Therefore, the design should also include flexibility if changes are to be made during the drilling operation. [5]

The life of an exploration well can be divided into three main phases. Well planning, well design and well execution. Where the well design is carried out in an early stage of the well planning. In drilling engineering the well planning and design phase can be the most demanding and time-consuming aspect of a drilling campaign. When considering exploration wells or wildcats, the actual operation phase can be as short as weeks or a few months. While the planning and data collection in advance can take several months, even years. A good well plan can save both expenses and overall emission. By utilizing better technology and time saving solutions, one can cut both material usage and rig days.

Up until recent times, all decisions made during well planning and well design have mostly been made with respect to:[6]

- Safety
- Cost- efficiency
- Applicability (usable)

The end result of a drilling campaign should therefore consist of a 'safely drilled, minimum-cost hole that satisfies the reservoir engineer's requirements for oil/gas production'. Even if the well planning procedures and practices vary among different operator companies, the goal is the same.[6]

2.2 NORWEGIAN OIL & GAS LEGISLATIONS AND REGULATIONS

The Norwegian oil and gas regulations are one of the worlds strictest. They are set to govern the petroleum related industry in Norway, both offshore and on the land site. By being so called 'risk-based', the regulations aim to reduce health, safety and environmental (HSE) risk. To follow up on the industry, the government awarded the executive authority to the Petroleum Safety Authority (PSA Norway, also known as Ptil). PSA as we know it today was established in 2004 as an independent, governmental supervisory body under the 'Norwegian Ministry of Labor and Social Inclusion'. From 1972 and up until 2004, the function of PSA was covered by the Norwegian Petroleum Directorate (NPD). As two individual units, PSA is responsible for the HSE and work environment, while NPD takes care of the commercial aspects in the petroleum industry[7]. The regulations are in most cases referring to the 'Norwegian Shelf's Competitive Position' standards (NORSOK). A standard which supplements and adds to the International (ISO) and European standards (CEN). NORSOK is developed to include the stricter safety framework and harsher climate conditions on the NCS. The standards aim to provides among other, a detailed description on how to achieve a safer and more cost-effective well and process.[8, 9]

The regulations and standards are affecting how operators design a well, the operational phase and end of well activities. In particular these regulations have specific requirements affecting the selection of: [10]

- Well fluids
- Casing and tubing
- Casing setting depth
- Specifications for well equipment (safety valves, production packers)
- Program preparation
- Operational procedures
- End of well reporting

2.3 WELL PLANNING

2.3.1 INTRODUCTION

An effective planning and review process are essential for achieving a successful drilling (and completion) project. It is an orderly process, and all details which can affect the project needs to be considered during the planning phase. The operators need to decide on an optimum drilling system for a particular well. Different systems have different limitations, which imposes constraints on the well design. These constraints need to be fully understood and accounted for in the planning process. All the well documentation needs to be in one place for easy retrieval, access and update. This will ease the reporting process and real time quality assurance.

The well planning process varies among different operator companies, and depends strongly on the well location and type of well. Even if the well planning practices and procedures are decided within each company, they are all designed to meet the regulations set by the authorities. Despite large operational variations, as mentioned a set of general guidelines and standards have been developed. Standards which are mainly based on experience gained from thousands of different wells worldwide.[10, 11]

Personnel safety always has the highest priority in well planning, and are placed above all other aspects in the plan. Loss of life or injured personnel is the worst outcome of an operation. Should one encounter unforeseen drilling problems during the operation that might endanger the crew, the plane would need to be altered. The safety aspect also includes safety of the environment and the well. The well is therefore designed to minimize the risk of blowouts and all other factors that might create leakage or spill. [11]

2.3.2 WELL PLANNING PROCEDURE

A well plan includes several smaller plans, which combined forms the final well plan. Figure 1 below shows a standard flow path during well planning. Starting off with a prospect, data collection and analysis of the pore and fracture pressure, before moving on to the design selection. Including the plans for cement, mud, bit, casing, drillstring etc. A suitable rig and cost estimations will also be presented during this phase.

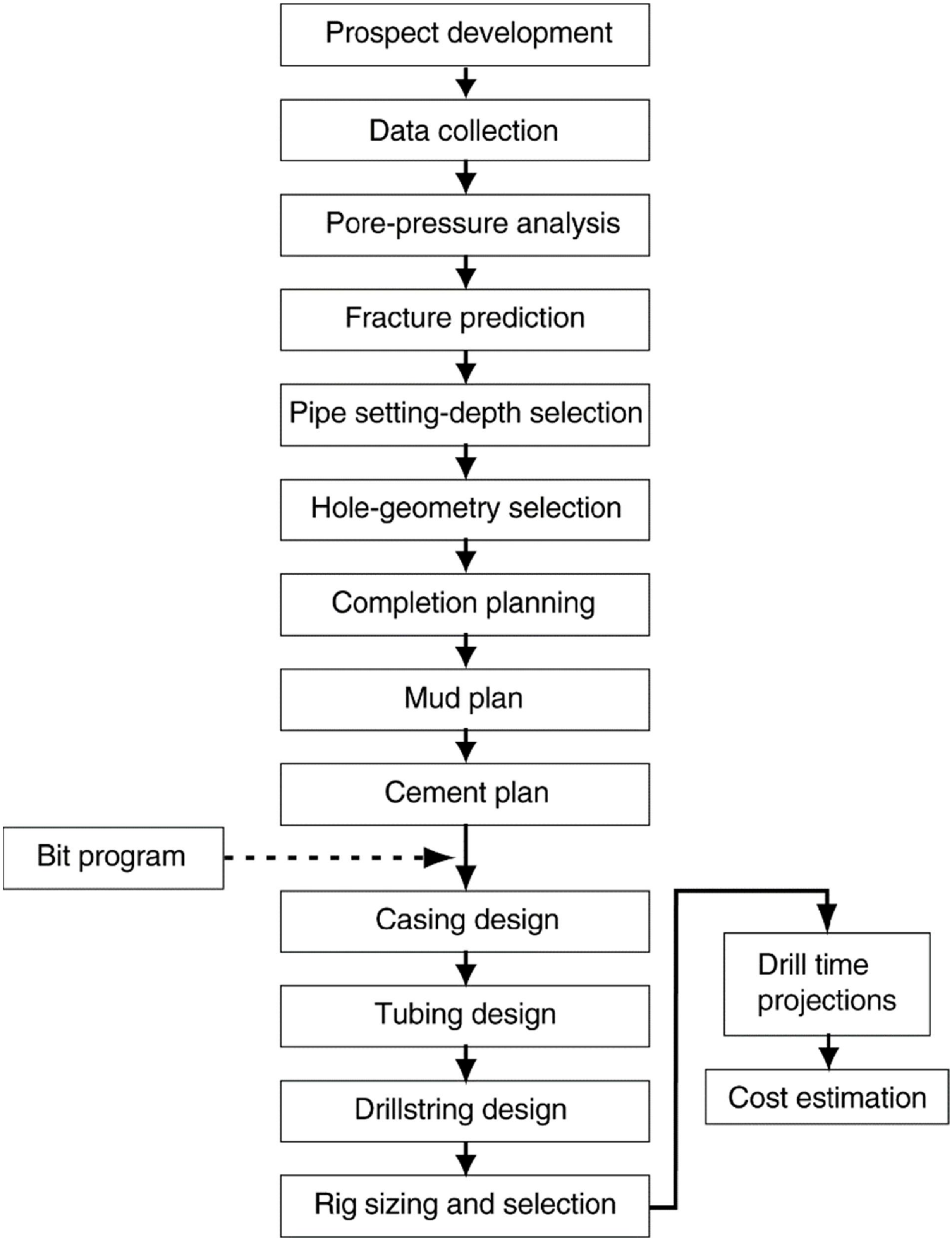

Figure 1: Example on flow path during well planning/design.[12]

More detailed, an activity flow during well planning normally includes:[10]

- **Establishing a Well Group:**
  - Geologists, geophysicists, subsurface group, reservoir engineers, drilling engineers (and completion engineers).
  - All to participate in regular meetings throughout the period prior to spud.
- **Initial meetings:**
  - Subsurface group presents their estimations on reservoir rock properties, pressure, temperature, oil in place (Monte Carlo simulations) etc. Suggest or require data to be collected during drilling (LWD/MWD data).
  - Drilling engineers prepares possible well paths in cooperation with their service company. To be presented and discussed in the well group.
  - Completion engineers starts looking on alternatives for the well completion (completion wells only).
- **Deciding on a Well Design:**
  - One specific well path will be chosen. Then the drilling (and completion) engineers will propose different well designs, with inputs from the service companies. This includes mud plan, drillstring design, drilling bit program, casing (and tubing) design and cement design.
  - To assess all the options, it is common to perform a SWOT (strength, weakness, opportunities, threats) analysis for all the different design alternatives.
- **Finalizing the well design:**
  - Several meetings and discussions are being carried out to make the best possible decisions. A mandatory ''Risk Analysis'' meeting between the operator and the service companies are performed. Includes consideration of all operational steps with respect to safety and economics. Normally by following the ALARP principle (As Low As Reasonable Possible), referring to risk minimization wherever possible, but not at all cost.
  - Well operation programs are being finalized and signed, including drilling program, completion program etc. Draft DOP's (Detailed Operational Plan) for each operational sequence are made onshore, before they get finalized and signed together with the offshore team some days ahead of each operation.
- **From operation to end of well:**

- As the spud date is approaching, a final meeting will be held by the operator to review the plan. Including both service companies and some of the rig crew.
- During operation, daily meetings are carried out between onshore and offshore personnel. Mainly to follow the process closely and discuss any changes needed.
- The last part of the project includes experience transfer and summarizing the project in an 'End Of Well Report' (EOWR). EOWR to include all deviations from the original plan, and lessons learned. Experience transfer among the company and the whole industry is a crucial part of preventing any future accidents or spills.

2.4 WELL DESIGN

Selecting a suited well design is an important part of the well planning process. Each well needs to be designed individually, and are based on subsurface measurements and experience gained from earlier or nearby wells. Often referred to as 'Offset analysis'. This experience-based approach may lead to challenges if the nearby area is unexplored (Wildcat well), or due to poor data quality from old offset wells. Wells drilled in the 70's, 80's and 90's are often lacking todays logging quality. Leading to inaccurate measurements and poor logs, and hence increasing the need for a flexible well design.[5]

2.4.1 CONCEPTUAL WELL DESIGN

To start the well design process, one would as mentioned make a conceptual design based on nearby wells or experience from drilling in similar formations. The offset analysis and conceptual well design form the basis for a detailed well design and future well decisions. The objective is to identify all possible questions or problems different designs could generate. In addition, it should consist of an action plan for the detailed design process in order to solve them. As an iterative process, the design can change consecutively as more data or new technology becomes available. However, altering the design includes re-iterating the entire process. Only by this one can make sure that all the underlying assumptions and problems have been accounted for in the altered design. It is therefore important to document properly all assumptions that have been made in each step of the design process, and immediately update when changes occur. As mentioned, the safety of personnel, environment and the well has the highest priority. Good documentation of the assumptions is therefore a mitigation action to prevent possible accidents. [10]

2.4.2 WELL DESIGN BASIC

The well design basis can be split into four main parts, which will be further elaborated:[10]

- Objectives
- Well environment
- Requirements
- Resources

OBJECTIVES. The objectives are set to define the purpose of the system, and future performance evaluation. The focus from the well team and well type, decides the objectives for a specific well (exploration or development well). Examples of some objectives:

- Making the project as simple, reliable and safe as possible.
- Minimizing initial capital and operating cost.
- Developing a flexible design for possible future operation (sidetrack, changes in well duty).
- Implementing state of art drilling technology and data acquisition.
- Providing for adequate surveillance and maintenance programs.
- Achieving optimum level of zone production or injection (production and injection wells).
- Developing a proper P&A program (exploration and production wells).
- Identify and handle possible drilling challenges (Casing setting depths, faults, formation stability issues, abnormal pore pressure etc.).
- Meeting requirements and developing optimal programs (casing, cement, drilling fluid etc.).

WELL ENVIRONMENT. Well environment refers to the environment of the well system. It includes physical properties, natural setting and administrative factors affecting the system. These factors originate from the nature itself, and can not be controlled. Environmental factors include, but are not limited to:

- Well location and climate (subsea, platform, weather etc.).
- Reservoir conditions (temperature, permeability, pressure, drive mechanism etc.).
- Fluid and rock properties throughout the well path.
- Total fluid management plan (TFM).

REQUIREMENTS & CONSTRAINTS. As previously mentioned, the requirements are set by Governmental Regulations for both exploration and production wells. Constraints in a well are inherent parts of the well system, which can limit the performance and therefore needs to be controlled. Some conditions that can develop downhole during the life cycle of an exploration well:

- Blowout.
- Loss of circulation, casing burst or collapse.
- Casing corrosion.
- Wax, hydrates.
- Zonal isolation problems.

Constraints can also occur due to pore communication between disciplines in the well team and 3 parties. The design and contribution from the different disciplines are strongly based upon each other, and it is therefore important to establish good communication routines at an early stage. Dialogs/meetings and documentation along each step of the process would therefore prevent misunderstandings and possible accidents. Examples on what lack of communication might affect the outcome of:

- Well design
- Subsea system
- Top side equipment
- Choice of inhibitors / stimulation chemicals

RESOURCES. Resources refers to all personnel involved in a well project, both onshore and offshore. The minimum required onshore personnel for an exploration well are:

- 1 Project Manager
- 1 Drilling Superintendent
- 1 Lead Drilling Engineers
- 2 Drilling Engineers
- 1 Operation Geologist
- 1 Reservoir Engineer
- 1 Geologist
- 1 Material/Logistic Coordinator
- 1 HSEQ Coordinator

- 1 Accountant/Cost Controller

The minimum required offshore personnel provided by the operator are:

- 2 Drilling Supervisors (24 hours duty)
- 2 Well Site Geologists (24 hours duty, only during well evaluation work)
- 1 Drilling Engineer

In addition, it is required to have dedicated representatives from the rig owner and the main service companies. These are to be involved in the well planning. Either throughout the complete planning phase, or only in selected meetings and work-shops. The Drilling Supervisors and Well site Geologists are also required to be involved in the well planning. How and to which extent they will be involved is decided within the project.[10]

2.4.3 WELL TYPES

For this thesis, the exploration well is the main well design. In addition, there are two other main well types, which can be defined from the 'Resource Management Regulations':[13]

- **Exploration well:** Drilled to test the hydrocarbon (HC) potential, or outline a proven deposit.
  - *Wildcat well* - A wildcat is located far away from previously drilled wells, or the data quality from nearby wells are poor. Leading to increased uncertainty of the subsurface geology.
  - *Appraisal well* - drilled in addition to wildcat wells if a sufficient petroleum deposit is detected. Main purpose is to establish the size and extent of the deposit.
- **Development well:** Drilled and completed for HC production, or productivity optimization of a production well.
  - *Production well* - drilled to produce HC or water for injection purposes.
  - *Injection well* - drilled to inject water, gas etc. back into the reservoir for waste storage or, improved HC recovery.
  - *Observation well* - development or test development well drilled to measure specific well parameters.
- **Shallow well:** Drilled to provide formation information and rock properties, and/or to perform surveys to evaluate an area of interest.

- *Route and soil surveys* - drilled to evaluate the subsurface before placing a facility. Depth restriction is 200 metres below the seabed.
- *Petroleum exploration* - drilled to acquire data on geological development of the formations at the drill site. The data is linked with seismic data for calibration of reflectors and depth converting purposes. Drilling deeper than 200 metres below seabed requires an application for consent to the PSA Norway.

To access the wells target, it might be necessary to deviate from the conventional well trajectory. Vertical, deviated and horizontal trajectories are common in both exploration and development drilling. Whereas designer and multilateral wells are used in production wells to increase the drainage area and hence increase the production from a reservoir: [14]

- **Conventional (vertical) well:** Drilled directly down to the target, in a vertically line. With only minor changes in inclination.
- **Deviated well:** Drilled at an angle less than 80 degrees.
- **Horizontal well:** Drilled at a high angel, greater than 80 degrees, into an established/potential reservoir.
- **Multilateral well:** Contains several well trajectories, branching from one main wellbore.
- **Designer well:** Are even more complicated than deviated and horizontal wells. One trajectory designed to address more than one target from the same wellbore.
- **Sidetracked well:** Drilled out from an existing well path, if it is decided during the operation to exit out of the well and reroute to another target.

2.5 TRADITIONAL WELL DESIGN

Different design options are chosen to facilitate a stable well, to avoid tight hole problems, casing burst or collapse, to prevent blowouts and loss of circulation. It is therefore crucial to optimize the well fluid, top hole solution and casing design to maintain the well integrity and prevent any wellbore failures[5]. The three main wellbore failures are related to casing burst, collapse and tensile failure. Casing burst occurs when the differential pressure between the inside and outside pressure regimes, exceeds the burst pressure tolerance for that specific casing. Meaning that the internal casing pressure exceeds the external pressure until failure occurs. Normally related to kick situations, when high pressure HC's enters the wellbore unintended. For collapse failure it is the opposite case. The external pressure from the annulus or formation, exceeds the internal casing pressure until collapse pressure is reached. Normally caused by a sudden reduction in the hydrostatic pressure inside the casing, due to lost circulation. Different casings come with different elasticity, ductility and shock tolerance limits. Tensile failure is related to applying forces that are exceeding these limits. Causing deformation, buckling, bending or tearing of the casing. These forces are mainly encountered during transportation, handling and while running the casing down the borehole.[1]

2.5.1 OVERVIEW

A subsea exploration well is traditionally starting off with a top hole and conductor casing, followed by a surface hole and casing. The wellhead (WH) is then attached to the surface casing, before the blowout preventer (BOP) is ran on a riser system and installed on the WH. The BOP provides pressure control and functions as a well barrier. With high pressure valves which can seal off the top of the well should a kick occur. The riser system protects the drillstring and transports cuttings, cement excess and displaced fluids from the wellbore and up to the rig. Preventing any unwanted discharges to the seabed. For a production/completion well the BOP is removed after a production liner/tubing is installed. And a Christmas tree (XT) is then installed on top of the WH to control the hydrocarbon (HC) flow once it reaches the surface. [1]

Deeper sections of the well are then being drilled, with decreasing bit sizes. Each section is being filled with a steel pipe, referred to as casing, to secure the borehole wall. A casing is made up of several joints with one thread and one pin end to join them together. The annulus space between the borehole and the casing string is then filled with cement slurry. All the way up to the previous section, or only partially. Once the cement has dried, it functions as a seal between the casing and borehole. Preventing fluid migration up through the annulus between the casing and borehole, hence also protecting the casing from corrosive formation fluids. [1]

How many sections a well consist off, depends on the planned well length, faults in the formation, and pressure regimes in the well path. The casing setting depth, referred to as the shoe depth, is determined based on when the current mud weight (MW) becomes insufficient for maintaining well integrity.[1]

2.5.2 DRILLING FLUID

The drilling mud has several functions, all crucial for a successful operation. Not fulfilling some of these criteria can lead to the formation caving in/collapse, lost circulation, poor hole cleaning, damaged drillstring/bit, tight hole/stuck pipe and hole enlargement. All which can stop or damage the operation, due to physical limits or increased risks.

The main functions of a drilling fluid:[1]

- Maintain wellbore stability.
- Cool and lubricate the drillstring and drilling bit.
- Transport formation samples to the surface.
- Prevent formation fluids from flowing into the wellbore.
- Cuttings removal from the wellbore.

Deciding on a mud weight (MW) is based on the estimated pore and fracture pressures in the drilling area, made with pressure data from offset wells or similar formations. In addition one need to consider potential kick scenarios, sealing off some potential lost circulation zones, suitable formation for casing shoe landing, while maintaining a stable wellbore. The purpose of designing the drilling fluid is to keep the MW above the pore pressure and below the fracture pressure to avoide typical drilling problems such as collapse, lost circulation, fracturing and differential sticking. Theory behind being to keep the well integrity and preventing unintended leakage from the formation into the wellbore by having a higher circulation pressure in the wellbore, than the pressure from the formation acting in on the wellbore. A mud weight lower than the pore pressure can lead to the well taking a kick, tight holes or collapsing of the well/casing. Not exceeding the fracture pressure is of equal importance, to prevent the drilling fluid from damaging and penetrating into the formation. Leading to washouts in an open hole, lost circulation or casing burst. [5]

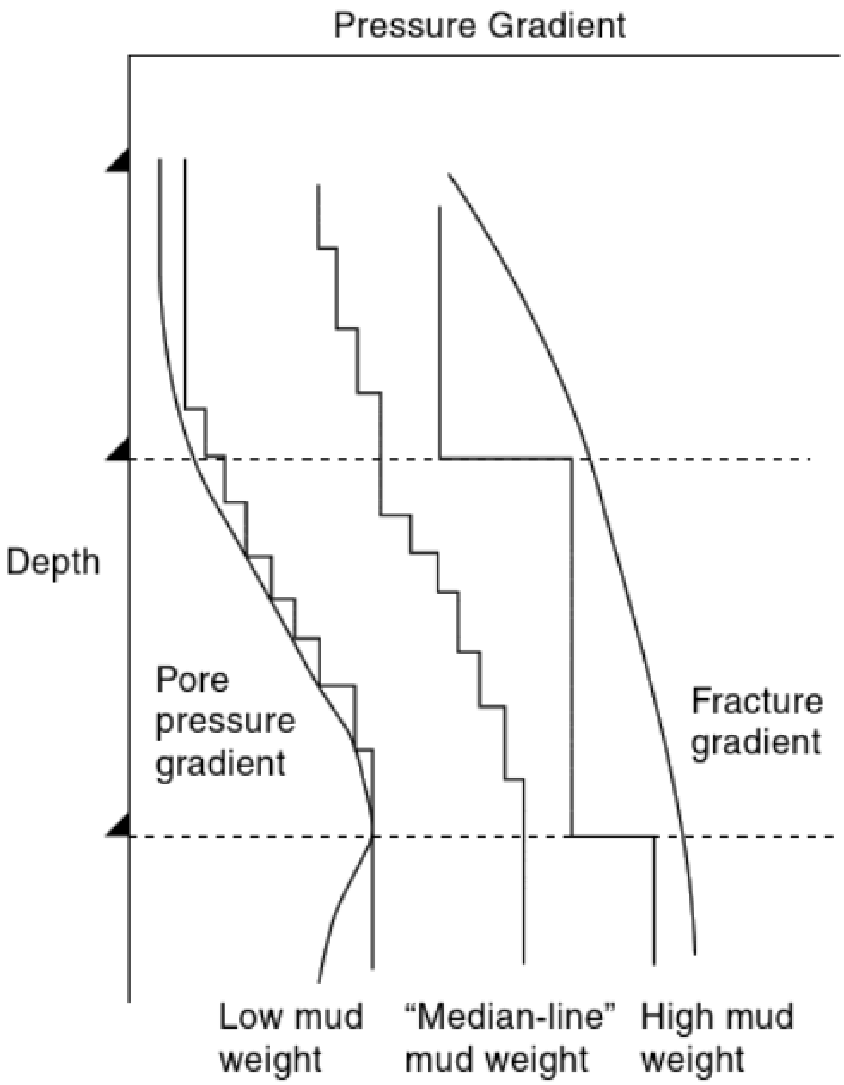

Figure 2: Typical mud weight options.[5]

Figure 2 illustrates the three most common MW design principals. Choosing a low mud weight, closer to the pore pressure, may cause wellbore collapse and tight hole due to fillings. It is assumed that a mud weight on the lower end can increase the drilling rate. A high mud weight design, closer to the fracture pressure, can lead to stuck pipe or mud losses to the formation. Normally selected for problem wells and highly deviated wells, since higher mud weight can aid better hole cleaning in deviated parts. Aadnoy et al. introduced the theory behind the ''Median-line'' mud weight. Which basically includes keeping the MW at an equal difference from the pore pressure and fracture pressure. Maintaining the borehole pressure as close to the mid-point as possible has proven to cause less wellbore problems compared to a high or low MW.[5]

The most commonly used mud types are water based mud (WBM) and oil base mud (OBM). WBM is based on seawater (SW) or freshwater mixed with some chemicals, while OBM has a continuous phase of oil. Adding barite to the WBM increases the weight, while potassium chloride (KCl) prevents the WBM from reacting with shale formations. The water in the OBM consists of oil coated droplets, preventing the water from reacting with the clays in the shale. Some other benefits from OBM is increased lubrication, temperature handling, lower formation damage and better wellbore stability. Resulting in fewer drilling problems and less wellbore damage than WBM. On the downside, a OBM is more expensive and less environmental friendly due to its oil content.[1]

2.5.3 CASING DESIGN

Casing off a hole, and cementing the casing in place, is the main solution to provide wellbore stability and preventing unwanted fluid leakage. The casing string needs to be able to withstand high pressures and temperatures, tensile and axial forces, and shock loads. Exceeding any of these tolerance limits may cause the casing to collapse, burst, tear or bend. To optimize the casing design, it is therefore common to customize the casing diameter, steel grade, weight, joint length, tolerance and wall thickness. [1, 5]

A proper casing and cement job aid the drilling process in several ways[5, 10]:

- **Zonal isolation**, by isolating different zones in the drilled formation (different pressures or contents). Includes sealing off fresh water zones or production zones to prevent fluid losses or contamination.
- **Stabilize the formation,** to avoid caverns, and prevent differential sticking of the drillstring due to unstable formations caving in. Prepares the wellbore for a higher MW when drilling deeper.
- **Preventing a blowout**, by sealing off high pressure zones from the surface.
- **Preparing for production,** by providing a smooth internal bore to aid installation of production equipment (production/completion wells).

The casing design process can be divided into three main steps; selecting setting depths and casing sizes; defining which operational scenarios that can result in casing burst, collapse, and axial loads applied to the casing; calculating the magnitude of these potential loads to decide on the best suited casing weight and grade to handle these.[1]

A traditional casing typically consists of the following casing strings, and are illustrated in Figure 3 below (includes a 7'' production liner) [10]:

- **Conductor casing (30'') – run in a 36'' hole**
  Cemented in place to prevent any drilling fluid circulation outside the casing, which can cause surface erosion and top hole instability if the soil collapses. Alternative sizes are 18'', 20'', 24'' and 36''.
- **Surface casing (20'') – run in a 30'', can be as a crossover in a 20'' x 13 3/8'' casing string**
  Cemented to prevent leakage from wellbore into formation and fresh water zones. Contamination of fresh water zones is of an environmental concern as well.
  Serves as an anchor for the BOP and support for the following casings. Alternative sizes are 24'', 18 5/8'', 16'' and 13 3/8''.
- **Intermediate casing (13 3/8 '') – run in a 17 ½'' hole**
  Cemented to prevent fracturing of the formation when the following sections are drilled with a higher MW, implementing a higher hydrostatic pressure in the wellbore. Fractured formation leads to loss of circulation in the wellbore and wellbore instability. Alternative sizes are 16'', 14''and 10 ¾''.
- **Production or intermediate casing/liner (9 5/8 '') – run in a 12 ¼'' hole**
  Production casing (or liner) cemented to prevent oil migrating to thief zones and to prevent drop in productivity due to formation caving into the wellbore. Steel casings are likely to suffer from corrosion, therefore a production tubing is normally used for producing the HC. Production tubing is normally 7'' or 5 ½'' pipe, creating a more stable fluid flow than larger casing diameters.
  Alternative sizes are 10 ¾'' and 7''.
- **Production liner (7 '') – run in a 8 ½'' hole**
  A liner is hung off just above the shoe in the previous casing, and not extended all the way up to the wellhead. This shortens the casing/liner length, hence reducing running time and cost. Alternative sizes are 9 5/8'' and 5 ½''.

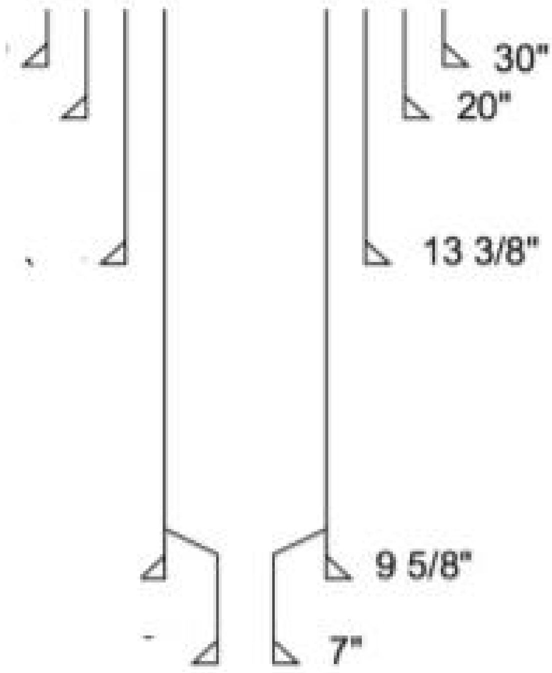

Figure 3: Conventional casing string design.[1]

2.5.4 DOPELESS CASING FROM TENARIS

To seal the casing connections during make -up, a thread compound referred to as "dope" is manually applied to each pin end on the casing joint. This goes for connections on both casings, production tubing's and liners, in exploration or production wells. Figure 4 illustrates both the pin end box end of a casing joint.

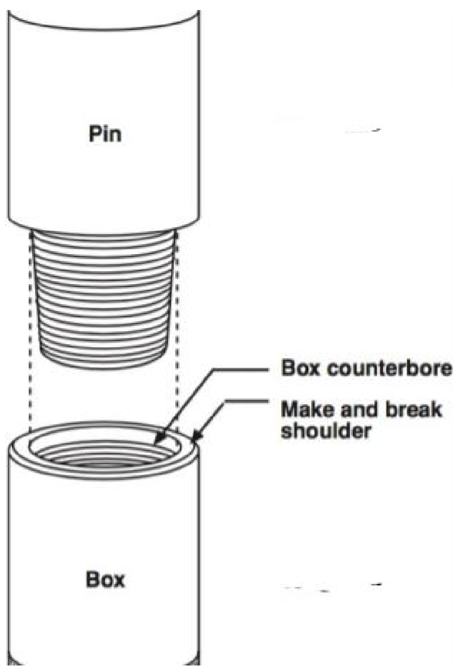

Figure 4: Illustration of a casing pin and box end which makes up a casing connection.[1]

Dope is a tchick grease substance made of different chemicals; some even includes oil. Meaning that any excess dope is a potentially hazardous waste. When running casings with up to several hundred joints, applying the dope on each pin end takes up rig time. Resulting in more costs and fuel consumption. Any spill to the drillfloor will lead to a safety risk and extra time spent on cleaning. Cleaning of crease often requires cleaning solvents and other chemicals which increases the chemical emission. Excess dope inside the casing can also lead to additional problems later on, and give some non-productional rig time (NPT).[15]

Today’s term ‘zero discharge’ originates from the Norwegian Government regulations, dated back to the early 1990’s. It included discharge limits for contaminated oil, aiming for zero unintended spills. One of the solutions to meet this requirement became ’Dopless Casing’ from Tenaris. In 2001 Tenaris was requested to make a new type of casing connection, to eliminate the need for dope. The result was the technology today known as ‘TenarisHydril Dopeless Technology’, with so called RunReady connections. In short terms the Dopeless technology consists of a dry coating being applied to the connections in the mill. Eliminating the use of running or storage dope on the rig. Being pre-coated in the mill allows for a fully automated and controlled process, supervised by specialized technicians for quality control. In addition to preventing the environmental contamination risk from dope, the Dopeless technology has proven to reduce the number of rejected joints and re-makeups in an operation. Less problems and less rig time with Dopeless casing joints can therefore reduce both cost, risks, rig time, fuel consumption and hence lower the environmental footprint from casing running.[15]

Tenaris is a global manufacturer, providing pipe and associated services to the energy industry. Not only do they deliver environmentally friendly products, Tenaris also aims to minimize their own eco-footprint during development and production. The Dopeless technology has been tested in over 60 countries around the world, and over a total distance of 44 million feet (13400 km). The first project to use Dopeless connections on all the casing and tubing was the Snohvit development outside Norway in the North Sea. Also known as a challenging region with an established fishing industry, a cold climate and a vulnerable ecosystem. Even in these conditions the Dopeless technology has proven to perform several years after installation. Due to the track record and its compliance to environmentally sensitive areas, it was chosen to only utilise Dopeless casings for the Toutatis project as well. [16]

The main quantifiable benefits from the Tenaris Dopeless Technology:[17]

- Eliminates the dope discharge, and hence lowering the environmental impact.
- Reduces personnel risks, due to a cleaner and safer drillfloor.
- Casing thread protectors are clean and can be reused on another pipe.
- Less operations on the pipe, eliminates the need for personnel to apply dope. Less pipe handling saves both rig time and reduces the risk for incidents and accidents.
- More reliable, nearly zero re-makeups or rejects from the testing.
- In total the running time can be reduced with up to 25%.

- Lowering the total pipe cost with up to 10%, due to less running time (on wells with 100% Dopeless casings).

2.5.1 LEAN WELL DESIGN

Instead of for example a 3 string design, meaning 3 different sections with casing and cement, some wells are being made with a more aggressive 2 string design. Meaning that the open hole section will be longer. Some designs include a liner hanged off in the previous casing, instead of a casing fully expended up to the WH. Saving even more casing joints and cement volume. A leaner well design does not only refer to less casing sections, but can also mean smaller wellbore radius. Resulting in less cuttings and drilling mud required for each section. By reducing the amount of casing/liner, cement, wellbore volume and mud volume, a slimmer design saves both running time, costs and emissions. On the downside, a larger openhole section can cause wellbore problems. Which in turn can halt the operation, require a rerun of the BHA and spending more rig time:

- Smaller wellbore radius:
  - Provides less cuttings, and hence less cuttings treatment and transportation.
  - Less mud required to drill each section, reduces bulk transfer, saves costs and chemical use.
- Less casing/liner strings:
  - Reduces the amount of casing materal, costs and environmental impact from manufacturing additional joint.
  - Less cement volumes needed, reduces bulk transfer, costs and chemical use.
- Longer openhole section:
  - Increases the risk of mud losses to the formation due to a longer unsealed section.
  - Risk of formation caving in to the wellbore.

2.5.2 SITE SURVEY

Performing a site survey refers to inspecting and gathering information on an area of interest. For a drilling operation this involves surveying the offshore location where operation is planned, and the nearby area. This includes identifying geohazards (boulders, shallow gas, faults, reactive clays, loose sands, habitats), seabed condition (dips, water depth, junk, debris, corals etc) and other environmental risks. This info is then utilized during the well planning phase to determine potential risks and the best suited spud location. Drilling in or close to an environmental sensitive area requires even more care to not harm any sensitive seabed habitats like corals[18, 19]. On the NCS, the protected cold water corals have not been fully mapped out. Operators on the NCS are therefore obligated to perform a site survey on the planed location before commencing any operations. The requirement includes to map possible corals within a 500 m radius from the well location.[20]

3 TOP HOLE SOLUTIONS

3.1 INTRO

When designing a subsea well, exploration or production, the conductor, surface casing and WH forms the base of the well. Meaning that several tons of weight from the well is transmitted to the seabed, where soil conditions can consist of up to several meters of soft formation. Penetrating further down in the seabed until firmer formation is reached, and casing it off, is therefore the main target for a top hole. The WH functions as a seal from the wellbore and as a guide base for the BOP by supporting its weight (and XT). Increasingly heavier BOP's, harsher drilling subsea environments, more complicated well designs and potential drift off, are all four components contributing to WH fatigue damage and increased axial loads. The WH and conductor system is therefore recognized as the ''weak link'' in well design. Since operators must ensure that the well foundation is strong enough to cope with all these loads, a smarter and stronger well foundation is needed to address these challenges. And making the top of the well more reliable and safe. [21, 22]

3.2 WELLHEAD SYSTEM

A standard 18 ¾'' subsea HPWH is normally welded onto the first 30'' or 36'' casing string, called conductor. The main functions of a wellhead are to establish a structural and pressure-containing interface for production and drilling equipment. It forms the basic foundation for the equipment on the seabed (drilling, production and workover equipment). This includes suspending, supporting and sealing off casing strings, supporting the BOP stack during drilling operations, and supporting the subsea tree after completion. An interface profile on the wellhead is commonly used to attach the BOP or subsea tree to the wellhead. To latch the subsea BOP stack and drilling riser back to the drilling rig. Offshore wellhead systems are either located on the surface (platform) or subsea (seafloor). A subsea wellhead will thereby be exposed to both internal and external pressure. Drilling at deeper water depths leads to increased external pressure on the WH.[23, 24]

Load cases and loading conditions to be considered when designing a wellhead housing (for drilling, production and workover): [24, 25]

- Pressure (internal and external)
- Thermal loads
- Radial loads
- Environmental loads
- Flowline loads
- Hydraulic connector loads
- Conductor housing reactions
- Suspended casing loads
- Tubing hanger reactions
- Riser forces (drilling, production and workover)
- BOP loads
- Subsea tree loads

Increased fatigue loads on the wellhead system is one of the main challenges faced by the industry today. Fatigue capacity is defined by “The wellhead systems capacity to withstand a dynamic load generated from the riser, BOP and/or XT”. These increased fatigue loads are mainly due to larger and thus heavier BOP’s, and more complex and time-consuming wells. A longer drilling or operational period means that the wellhead and conductor system face extended loads over a longer time period.

In addition to these external loads, the wellhead and other subsea equipment faces the following challenges:[26]

- Remoteness (challenges related to monitoring or inspections of equipment)
- Flow assurance considerations (lower temperatures subsea- hydrates issues)
- Subsea environment (tides, currents, seawater corrosion etc.)
- Increased hydrostatic pressure (water column above subsea equipment)

A subsea wellhead system is normally made up of:[3]

- **Drilling Guide Base**
  - Guiding and aligning the BOP to the wellhead
  - Guide-wires from the rig attached to a base running the wire down to the WH
- **Low-Pressure WH Housing- LPWH (30” or 36” conductor casing/housing)**
  - Location point for the guide base
  - Interface for the 18 ¾” high-pressure WH housing
- **High-Pressure WH Housing- HPWH (18 3/4”)**
  - The interface between BOP or tree to the well.
  - Landing shoulder and support for casing hangers
- **Casing Hangers** (one for each casing size) **& Seal Assembly**
  - Casing hangers provides a sealing area for the seal assembly to seal off the annulus between casing hanger and WH for pressure isolation
  - Casing loads transferred from casing hangers to the WH landing shoulder
  - Flow-by slots in each casing hanger for fluid and cement passage
- **Bore Protectors &Wear Bushings** (different sizes)
  - To protect internal surfaces at the critical landing and sealing areas in the WH system
- **Running & Test Tools**
  - *Conductor WH Running Tool*- runs the conductor casing, conductor WH and guide base. Used for jetting or cementing the conductor in place.
  - *High-Pressure WH running tool*- runs the HP-WH and 20” casing
  - *Casing-Hanger & Seal-Assembly running tool*- runs the casing, casing hanger and seal assembly all in one trip. Facilitates testing of the seal-assembly and BOP after installation. Possible to retrieve seal-assembly if needed.
  - *Multipurpose Tool & Accessories*- run and retrieve the nominal bore protector and wear bushings. Retrieves seal-assembly. Jet sub can be attached to the tool for WH washout during tool retrieval, and another adapter can be attached for milling and flush operations.
  - *BOP Isolation Test Tool*- for testing of the BOP stack without pressurizing the casing-hanger seal assembly.
  - *Seal-Assembly Running Tool*- whenever a second seal assembly is needed. Can pressure test BOP and retrieve seal-assembly if debris is encountered.

Figure 5 illustrates a subsea WH system with an 18 ¾" HPWH inside the 30" LPWH housing (conductor). A system like this is typically designed for handling pressures rates of 10'000-15'000 psi, and with a carrying capacity of up to 3200 tons. In addition to the 30" conductor, the casing program consists of 20", 13 3/8", 9 5/8" and 7" casings. The 13 3/8", 9 5/8" and 7" casings are hanged-off by tubing/casing hangers inside the HPWH housing. Starting with the largest casing sizes at the low end of the wellhead, and building upwards. The seal assemblies are sealing off the annulus between the casing hanger and WH. On this figure a temporary abandonment cap is placed on the top of the wellhead. This can be replaced by a corrosion cap over the wellhead for contamination protection (debris, marine growth, corrosion etc.). [21, 25]

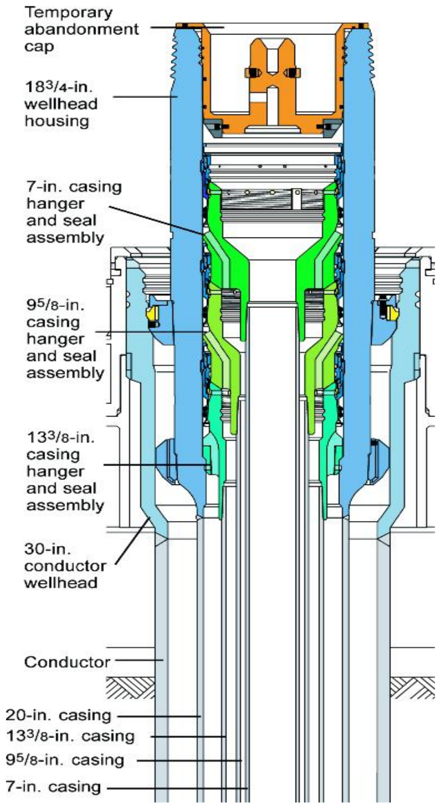

Figure 5: Typical sebsea WH system.[3]

3.3 CONDUCTOR

Conductor refers to the first casing which is run and cemented into a predrilled top hole, or hammered down in soft formations. Forming the first well section, stabilizing the unconsolidated formation and providing a structural wellhead foundation on the seabed. With casing lengths normally ranging from 40 – 300 ft. As the base of the well and part of the WH system, it is also a part of the ''weak link''. The traditional conductor system is used in most well designs, only differing in the radial size.[3, 22]

3.4 CONDUCTOR ANCHOR NODE (CAN)

Conventional wellhead systems are recognized as the "weak link" in well design due to the associated risks and fatigue related issues. The conductor anchor node (CAN) by Neodrill is a technical solution to provide a smarter well foundation. Lowering the risks countered with a conventional WH system, for both exploration and production wells. The CAN consists of a suction anchor and one joint of conductor. The suction anchor provides a more reliable top support for the well, by pushing the conductor into the seabed. Not only resting on top of the seabed as in a conventional system. Hence improving safety and reducing the WH related risks and fatigue issues.[22]

The first CAN solution was utilized in 2006, and as per 2020 a total of 24 CAN installations has been made worldwide. The system has proven to be suitable for installation in several seabed conditions. So far, the majority have been installed in clay formations, sand formation, mixed formation with both sand and clay, and soft limestone formation. Once installed, the CAN provides less or no risk of fatigue issues. With a proven inclination < 1 degree on all projects, and in water depths ranging from 100-1500m. Limitations for working depths are set by the length of the installation crane wire on the vessel or the rig. The construction can be installed with light vessel before the rig arrives on location, cutting both rig time and cost. [27]

In total, there are more benefits from choosing a CAN system, than risks. The main risks being penetration issues and the need for re-spud on another location. Boulders and the soil condition can lead to an unsuccessful CAN installation. It is therefore crucial to have a good site survey and evaluation of the area to avoid the penetration issues and the risk of needing to run a conventional conductor string. The main benefits from implementing a CAN system in the well design are listed below:[27]

- **Economical value:**
    - Saves rig time, hence fuel, and casing material when eliminating top hole drilling and conductor installation.
    - A more cost effective well template.
- **Risk mitigation and HSE value:**
    - Risk reduction due to less logistics and heavy lifts (conductor installations from the rig requires an additional handling step from the vessel to the rig).
    - Eliminates the risk of conductor equipment failure.
    - No cement risks, less bulk handling to the rig and supply vessel (bulk handling creates a potential risk for spills).
    - Less service personnel required on location, no need for cementers and personnel for the bottom hole assembly.
    - Less inclination issues, reduces the risk of re-spud.
    - Improved bending control management.
    - Load capacity calculated and verified for the expected loads.
    - Fatigue issues reduced to zero or minimized, better operability.

    - Simplified and reduced rig time for P&A (the well string is cut and the CAN-ductor retrieved by a boat after P&A).
    - Less ‘Open Water operations’ (reduced time between spudding the well and running BOP on the riser).
    - Reduces risks of WOW, ROV and other NPT (none production time) during spud.
- **Reduction in the environmental footprint:**
    - Eliminates cuttings and cement disposal from conductor installation.
    - Possible to implement a riserless mud recovery system, eliminating cuttings to the seabed during open water operations.
    - Reduced rig time implements lower fuel consumption, and less CO_2 and NOx emission.
    - Once retrieved from the seabed, the CAN-ductor can be prepared and reused on another well.
- **Technical enabler:**
    - Allows for shallower kick-off points when trying to reach shallower reservoirs.
    - Better WH support in soft formations.

3.4.1 DIFFERENT CAN- SOLUTIONS

There are three different CAN- based solutions which are illustrated in Figure 6 below. CAN-basic and -ductor are designed for exploration wells, while the CAN- integrator can help accelerating the field production from producing wells.[22]

Figure 6: CAN - based solutions. @Neodrill

CAN-basic forms the base for all four CAN solutions, and functions as the well foundation. Common for all CAN solutions is therefore a conductor with the suction anchor which pushes the guide pipe into the seabed/formation. Once in place, this well foundation provides a stable platform with high load capacity. The CAN- basic is mainly designed for exploration wells, and functions as a load carrier for conductor jetting.[28]

CAN-ductor was the design used on the Toutatis project, and also the scope of the top-hole report in chapter 3.5 below. It consists of a CAN- basic with a short conductor and WH pre-installed into the CAN. Among other the solution allows for shallow kick-off point, enabling horizontal drilling into shallow reservoirs. This was proven when Wisting Central II on the NCS became the shallowest horizontal well ever drilled from a floating unit, by utilizing a CAN- ductor. With the kick-off point starting at 10 m, they were able to drill horizontally into the reservoir at 250 m. In addition to shallow kick-off, the design delivers simplified P&A operations and mitigates some of the most common top-hole related risks. Figure 4 illustrates a rig-installed conductor, cemented in place in a pre-drilled hole, and a vessel installed CAN-ductor. The traditional set conductor has the shallowest possible kick-off point at 50 m, 40 m deeper than the shallowest for a CAN- ductor. The figure also summarizes the rest of the benefits from choosing the CAN based solution:[28]

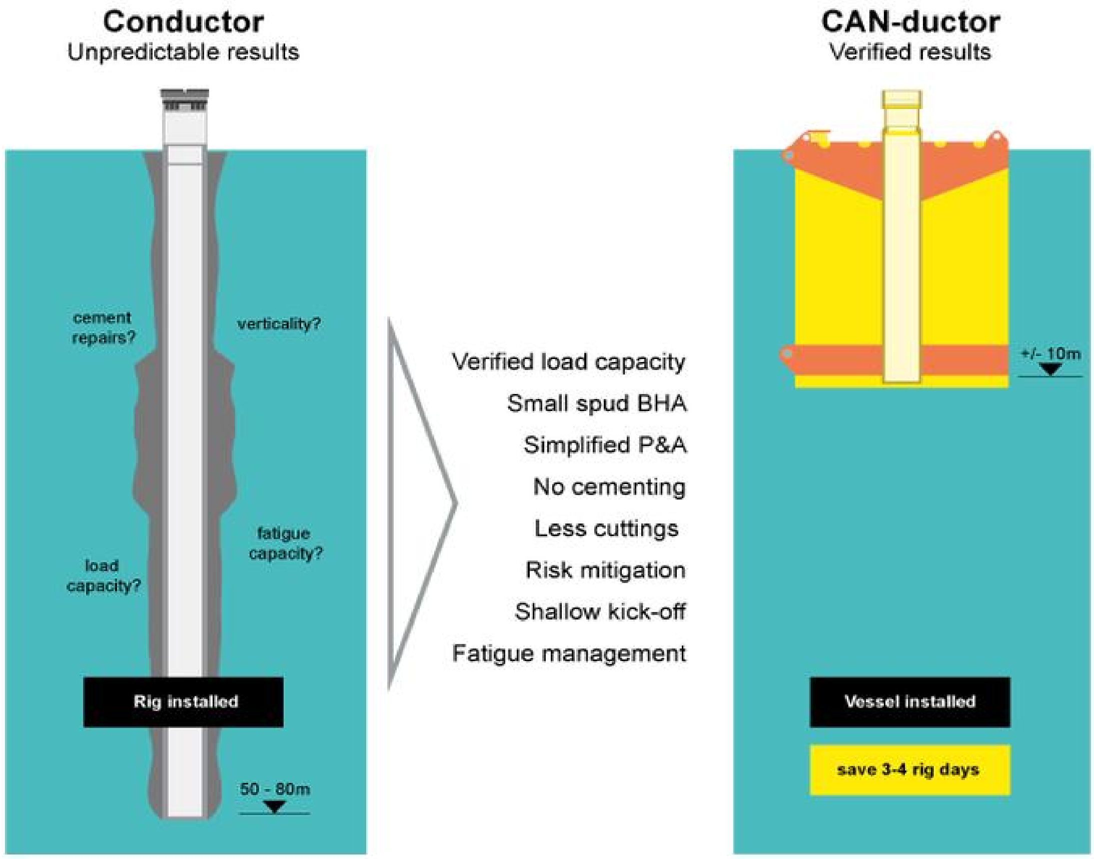

Figure 7: Conventional conductor and the benefits of a CAN- ductor. @Neodrill

CAN-integrator is designed for subsea development wells, and intend to facilitate early production. The system works as an integrator between SURF (subsea, umbilical, riser, flowlines), SPS (subsea production system) and drilling. Made possible by having the SPS system and protection structure mounted on top of the CAN in the workshop. In a traditional single production well design the hole is first being drilled with a specific vessel, while the infrastructure like flow lines are being completed afterwards with another vessel. Causing a halt between well completion and start-up of the production. With the use of CAN technology most of the marine and SURF operations can be done before the drilling rig arrives on location. When the well is finalised and plugged by cement, a vessel can cut the casing string from the CAN and retrieve it. This goes for all the CAN systems. Saving up to several days with rig time, hence money, implement reuse of equipment and allowing for an earlier production start.[29]

3.5 CONDUCTOR VS CAN-DUCTOR

In 2019 the CAN- ductor technology was compared to a conventional drilled well in an environmental life cycle assessment report (LCA) by Asplan Viak[30], a Norwegian architectural and consulting engineering firm. Bases on technology information from Neodrill on the Cambo well in the UK (drilled by Siccar Point Energy in 2018), and a previous LCA study made by Asplan Viak on the casing operations associated with a top hole (42’’ and 36’’) for a production well. A report making it easier to put an actual number on the benefits from a CAN system. The CAN-ductor system evaluated in this report, is almost the same system as used in the Toutatis campaign. Main difference being that the CAN- ductor system on Toutatis did not make use of the riserless cuttings removal system, and instead disposed the cuttings to the seabed.[30]

3.5.1 SCOPE OF THE REPORT

The scope of this work was to quantify and compare the environmental impact from a CAN-ductor drilled well, to that of a conventionally drilled well. To evaluate the two options the processes was evaluated in detail, and the outcome was compared across eight environmental impact categories. The main inputs in the analysis included casing materials, drilling fluids, cement, drilling and supply vessels, waste treatment process and the installation, production, maintenance and removal sequences for the CAN- ductor system.[30, 31]

Both wells were assumed to have the same offshore conditions and location, at 1100 m sea depth with a well depth of 700 m, and 200 km from the onshore mobilization port. For the conceptional drilled well the 42" top hole is drilled 100 m below seabed, followed by a 600 m long 17 ½" hole. Both top hole options are illustrated in Figure 8 below.[30]

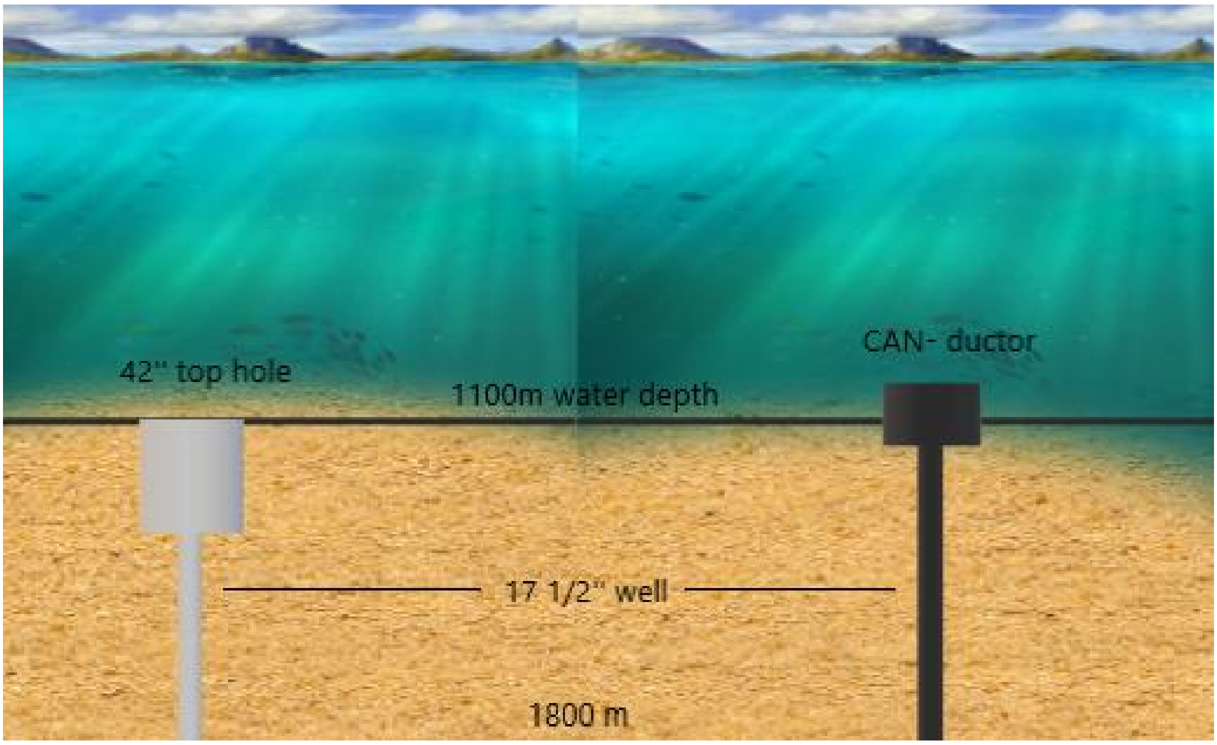

Figure 8: Well schematic of a conventional well and a CAN-ductor solution.

3.5.2 CONVENTIONAL WELL

The conventional well is initiated by drilling a 42" top hole from seabed and 100 m down in the formation. The top hole is drilled with a so-called spud-mud for cuttings transportation, cooling and lubrication of the drill bit, well stabilization and down-hole pressure maintaining. (The spud mud contains some heavy metals, and leaching of these metals are therefore considered in the analysis). To estimate the required mud volume, it is estimated to use 223 m^3 of spud mud, approximately 2.5 times the hole volume. Leaving a total of 95 m^3 top hole cuttings to be deposited on the seabed. After circulating clean the top hole, a 82 tons steel conductor is installed in the open hole. The conductor is then cemented in place by filling up the annulus between the top hole and conductor, in addition to the shoe track inside of the conductor. To ensure 200% excess the total cement volume required is 70 m^3. The cement excess amount is to ensure that the annulus between the top hole and the conductor is filled up entirely all the way up to the seabed. When the cement has set, a selected bottom hole assembly

(BHA) is made up to drill out the shoetrack. Both the drilled cement from the shoe track and the excess cement are deposited on the seabed. This first step is estimated to take 3 days on average, and is followed by drilling a 9 5/8” pilot hole, adding another 2 days to the operation.

The well section consists of drilling a 17 ½” hole, 600 m down from the foot of the conductor. With an estimated disposal volume of 0.16 m^3/m, the total of 80 m^3 with cuttings from the well section will be discarded on the seabed. A water-based mud (WBM) is used for drilling and cuttings transportation. The next step is to install a 13 3/8” surface casing made up of 54 tons of steel, in addition to the 18 3/8” WH. The surface casing is then cemented in place by filling up the outer annulus with 75 m^3 of cement. This section will on average take a total of 5 days.[30]

In the sensitivity analysis the impacts of choosing a 36” top hole instead of the 42” was also considered. The size of the top hole and conductor is selected based on the local soil conditions. A smaller top hole does not give a shorter operation time, but the impact can be seen in reduced cement volumes and cutting disposal. The 42” hole generates 175 m^3 of cuttings in total and uses 145 m^3 of cement, whereas a 36” hole leads to 150 m^3 of cuttings and 120 m^3 of cement.

3.5.3 CAMBO WELL (CAN TECHNOLOGY)

The Cambo well was drilled outside UK in 2018, and became the base for the CAN technology analysis in this report. The 100 tons unit was transported to location and installed by a vessel, and remained in place for the whole lifetime of the well. After this one well the CAN is set to be transported back to shore for maintenance. Even if this particular CAN-ductor has an assumed lifetime of 10 wells. The first stage took 2 days and included installing the CAN-ductor and drilling a 9 5/8” pilot hole. The CAN- ductor was placed down on the seabed, and submerged into the soil to form the well foundation. This eliminated top hole drilling, spud mud, conductor installation and cementing behind the conductor. Eliminating cuttings disposal and the need for spud mud, also eliminates leaching of heavy metals. Once the CAN-ductor was set in place, the 9 5/8” pilot hole was drilled off location.

The next operational stage was to drill the 17 1/2” well path with WBM, 700 m below the seabed. With 0.16 m3/m, this section generated a total of 95 m^3 with cuttings. With a docking point on the CAN unit, the cuttings were pumped on to the rig to be transported to shore for deposit and controlled landfill. After cuttings removal, the 20 x 13 3/8” surface casing was installed and cemented in place. The casing consisted of 63 tons of steel, and the cement volume used was 75 m^3. This final stage of operation took 4 days in total.

Cement volumes, cuttings volumes and drilling times for all three solutions are summarized in Table 1 below. The selected top-hole size is normally dictated by number of casing strings to be run, and local soil conditions.

	Conventional well (42" Top Hole)	**Conventional well (36" Top Hole)**	**CAN- ductor**
Drilling Time (Rig Time):			
Drill 42" hole + set conductor	3 days	3 days	-
Drill 9 5/8" pilot hole	2 days	2 days	2 days
Drill 17 ½" hole + set 13 3/8"	5 days	5 days	4 days
Total	10 days	10 days	6 days
Cuttings disposal volumes:			
42 "@ 0.95 m^3/m	95 m^3	70 m^3	-
17 ½" @ 0.16 m^3/m	80 m^3	80 m^3	95 m^3 (to rig)
Total	175 m^3	150 m^3	95 m^3
Cement volumes (seabed return):			
Conductor (200% excess)	70 m^3	70 m^3	-
Surface casing (20 x 13 3/8")	75 m^3	50 m^3	75 m^3
Total	145 m^3	120 m^3	75 m^3

Table 1: Rig times and volumes from a well with CAN- ductor, compared to a 42'' and a 36'' tophole design.

The sensitivity analysis for the CAN technology included two alternative scenarios to the Cambo operation, in addition to the 36'' top hole instead of 42''. The alternative scenario considered cuttings disposal on the seabed instead of recovering to the rig and transportation to an onshore disposal facility. The third scenario assumed a CAN unit was only used for 1 well, instead of potentially 10 wells. [30]

3.5.4 ENVIRONMENTAL IMPACT CATEGORIES

For this report a total of eight environmental impact categories were evaluated and defined as:[30]

- **Climate change:** aggregate impact from greenhouse gas emissions (CO2- equivalents).
- **Human toxicity:** including respiratory, toxic and carcinogenic routes of health damage (1.4-dichlorobenzen equivalents).
- **Particular matter formation:** formation of fine particles up to 10 um in diameter, which may cause health problems of the upper respiratory tract when inhaled (PM10 equivalents).
- **Terrestrial acidification:** air emissions (mainly SO_2, NOx, and NH_3) leading to acidification of soils (SO_2-equivalents).
- **Freshwater eutrophication:** nutrient enrichment through P in freshwater bodies (P-equivalents).
- **Marine eutrophication:** nutrient enrichment through N in marine water bodies (N-equivalents).
- **NOx:** nitrogen oxides produced from incomplete combustion and a precursor to smog and acidification.
- **SOx:** sulfur oxides produced from combustion of sulfur-containing fuels, such as coal and oil, and is a contributor to acidification.

The selected categories were chosen to be the most relevant ones with respect to the studied technologies. The impact assessments (LCIA) in this LCA were calculated by the ReCiPe characterization method. A method which 'translates emission and resource extractions into a limited number of environmental impact scores by means of so-called characterisation factors'.[32]

3.5.5 SENSITIVITY ANALYSES RESULTS

Figure 9 illustrates and compares the outcome of the sensitivity analyses. The blue lines represent a traditional conductor system, while grey denotes wells with the CAN-ductor technology. Measured in the percentage of environmental impact each scenario had. Among all scenarios, the well with a 42'' top hole had the highest environmental impact in five out of eight categories. Regarding human toxicity, SOx emission and freshwater contamination, the highest environmental footprint came from the CAN- ductor system with a lifetime of one well. Further, the 36'' top hole lead to 0,44-10% lower environmental impact than the 42'' top hole. Mainly due to reduced cuttings and cement volumes since the hole is smaller. Even if a smaller top hole induces environmental benefits, the CAN- ductor still had lower impact up to 40%. Comparing cuttings recovery over seabed disposal turned out to have quite low environmental impact. Due to the need for bulk transfer to a vessel, and further transport to shore. While reducing the CAN-ductors lifetime from 10 wells to only 1 well, reduces the overall environmental effect of the system. Mainly due to not being able to reinstall the same CAN in another well, creating a need for producing more new CAN units.

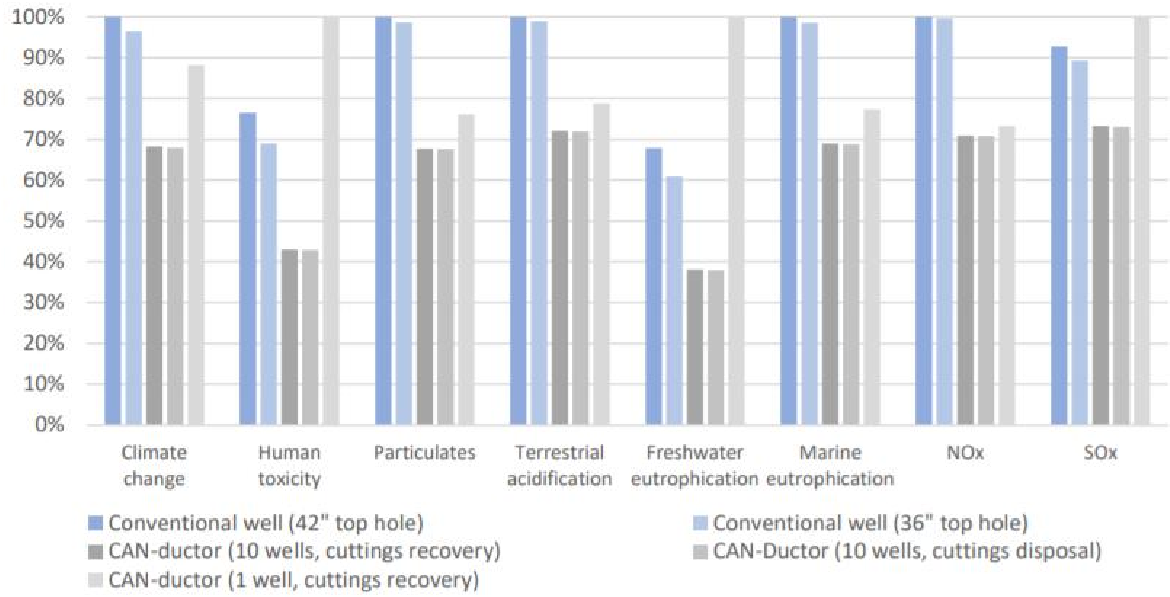

Figure 9: Result of the sensitivity analyses.[30]

3.5.6 MAIN RESULTS AND DISCUSSION

The CAN -ductor technology provided several operational and environmental benefits compared to a conventional conductor. Including cost, use of tools and special equipment, cement service crew, logistics, transport, and HSE aspects. Table 2 below states the significantly reduced environmental impact from choosing a CAN. For this particular case, it resulted in an environmental improvement of approximately 24-44% in the 8 categories. Gas emissions from CO_2 was lowered by 32%, reducing the negative climate effect by almost one third. The associated health damage from 1.4-diochlorbenzen was reduced by as much as 44%, and the air emission from NOx and SOx was lowered by 30% and 24% respectively.

Impact Category	**Unit**	**Conventional well**	**CAN-ductor**	**Reduced impact by CAN**
Climate change	T CO2 eq.	1 629	1 112	32 %
Human toxicity	T 1.4-DCB eq.	266	149	44 %
Particulate matter formation	T PM10 eq.	8.8	6.0	32 %
Terrestrial acidification	T SO2 eq.	16	11	32 %
Freshwater eutrophication	t P eq.	0.21	0.12	43 %
Marine eutrophication	t N eq.	1.01	0.69	32 %
NOx	t NOx	24	17	30 %
SOx	t SOx	2.5	1.9	24 %

Table 2: Comparing the total environmental impacts of conventional and CAN- ductor technologies.

The largest environmental impact came from rig time (mostly fuel), and the amount of conductor casing (steel and cement). Reducing the casing joints in the well design reduces the need for steel and cement. Rig fuel and well materials are the biggest contributors to the emission, and hence the most effective components to reduce when trying to lower the environmental impact. Drilling fluid, production and installation of the CAN – ductor had less of an impact on the environmental footprint, while the impact from cuttings treatment and CAN – ductor maintenance was quite low. Even by being low, they all had a positive impact on the environmental footprint from the CAN system. In addition, by eliminating disposal of cuttings, leaking of heavy metal to the marine life is reduced. Quantifying the benefits from eliminating cuttings disposal was not a part of the scope in this report.

Table 3 summarizes the differences in rig time, material usage (steel), cement volume, spud drilling mud and tophole cuttings disposal. Showing a significantly lower CO_2 emission from a CAN – ductor compared to a conventional well, in all five categories. A reduction equivalent to approximately 683 tons CO_2 for these categories

	Physical quantities		**Climate change impact (t CO_2 – eq)**	
	Conventional well	CAN- ductor	Conventional well	CAN- ductor
Rig time (days)	10	6	1209	725
Steel (tons)	136	73	234	137
Casing cement (m^3)	145	75	160	83
Spud mud (m^3)	223	0	25	0
Cuttings discharge (m^3)	175	0	-	-
TOTAL	-	-	1628	945

Table 3: Main benefits from the CAN- ductor including required supplies and corresponding CO2 emission.

4 ANCHOR VS. DYNAMIC POSITIONING

4.1 OFFSHORE DRILLING RIGS

Most of today's offshore exploration and development wells on the NCS are being drilled from jack-ups, semisubmersibles or drillships. Jack-up rigs consist of three or four movable legs with the ability to extend above or below the drilling deck. Once on location, the legs are being jacked downwards into or onto the sea floor. The legs then function as the rigs anchor, and are able to keep the unit stable during drilling operations. On the downside the jack-ups are only suitable for operating in shallower water depths, with the deepest reaching up to 500 feet. [33]

Semisubmersibles and drillships on the other hand, are floating units that can operate in both deep and ultra-deep water. Semis have working deck like a jack-up. But instead of legs, the deck is mounted on to pontoons and hollow columns for floating purposes. By adjusting the amount of seawater in the pontoons and columns, it is possible to submerge or rise the unit. When being submerged the semis are stable enough to handle rough waters, some of them can even operate in water depths up to 10,000 feet. Drillships can drill in water depths up to 12,000 feet, but they lack the stability of semisubmersibles in rough weather. Floating units are connected with a riser system to the seafloor. The riser system also serves as protection for drilling and production equipment against ocean current and waves.[33]

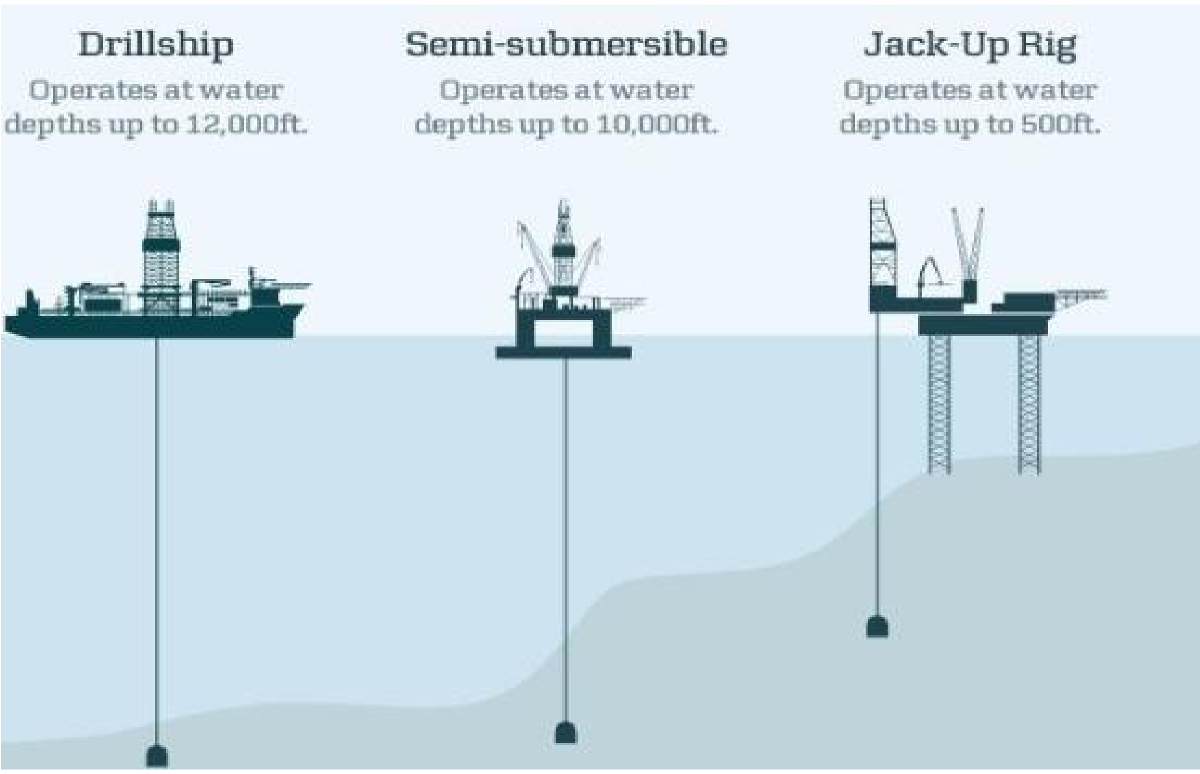

Figure 10: Illustration of a drillship, jack-up and a semi-submersible.[34]

Since semis and drillships are floating and not attached to the seabed, it is crucial to have other systems in place for station keeping during operations. The two systems in place today are anchoring (mooring) system and dynamic positioning (DP) system. They are developed to reduce the vessels movement to an acceptable level, while keeping it above target. Just a slight unintended dislocation can affect the operation and cause damage to the vessel, drilling equipment and riser. Leading to a halt in production or drilling due to repairs. And even more severe, compromising the safety of the offshore personnel and the environment. A possible leak path from a damaged WH/XT/BOP or riser can lead to severe unintended emissions.[35]

4.2 ANCHORING & POSTMOORING SYSTEM

Floating units can be anchored to the ocean floor in the same way as regular boats. Several mooring lines functions as connections between the floating facility and the anchors on the seafloor. The tension transmitted from the mooring lines to the anchors creates enough force to counterbalance the environmental forces. The winches onboard the rig creates this anchor tension by adjusting the length of the mooring line. The anchor and lines are laid out in a specific 'mooring pattern' around the unit, often symmetrically in the plan view. Figure 7 shows an example of a semi-submersible rig being anchored to the seabed with 6 mooring lines and 6 anchors. The catenary shape of the mooring lines depends on an increase/decrease in line tension.[36, 37]

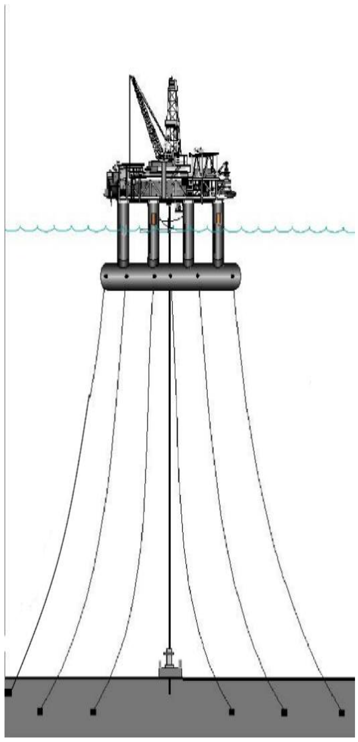

Figure 11: Illustration of a semi-submersible rig.[2]

Anchor handling vessels (AHV) are used for pre-laying the anchors and lines, in addition to performing connections. Sailing time for AHV's and work time on location makes it a time consuming and expensive operation. Even if the anchors are set upon rig arrival, the hook up to the rig will still halt the operation with several days or weeks. For exploration wells with a short timeframe, the anchor handling process might require as much as 10-20% of the wells total cost.[36]

Overall, a typical mooring system consist of four components; the anchor, the winch, the mooring line and the connectors:[37]

Moring lines are spooled onto a drum. Some of the most used materials are chain, wire rope and synthetic fibre rope.

Mooring connectors can include shackles, connecting link kenter type, connecting link pear shape, connecting link c type and swivels. The main purpose of connectors is to connect two pieces of mooring line, with either equal or different shapes.

Some different **Anchor** types are dead weight anchors, drag embedment anchors, pile and gravitation anchors, suction anchors and vertical load anchors. Common for all types are that they penetrate, with different depths, into the seafloor to create a holding effect.

Anchor winches on the rig are used for storage and handling of the mooring line drum. The size of the winch limits the amount of line to be spooled onto the drum.

The design criteria for a mooring system are based on safety, environment, station keeping capabilities, rig capacity and operational constraints. In relation to the drilling permit, the marine life and soil conditions are mapped out in a site survey. The results from this survey will affect the mooring system design, including anchor placement and the mooring pattern. If proper considerations on anchor placement are not made, one risks causing severe harm to the marine life.[36, 37]

4.3 DYNAMIC POSITIONING SYSTEM

Vessels are subjected to forces from waves, current and wind. The DP system compensates for this external impact by using the unit's own propellers and thrusters, controlled by an automatic computer system. In order to compensate for impacts from every direction, the thrusters are placed in the front, back and at each side of the unit. Majority of the floating rigs built during the last 10 years are equipped with a DP system. For a newbuilt unit the expenses of choosing a DP system versus a mooring system are almost in line. As well as for station keeping, the DP system is used for accurate manoeuvring and track keeping (cable/pipe laying). The system can be categorized into three different classes, depending on the level of redundancy it applies:[38, 39]

(Common for all three classes is both manual and automatic heading and position control)

- **DP Class 1 (DP1)-** No redundancy. A single fault can lead to loss of vessel position and system fail.
- **DP Class 2 (DP2)-** Includes redundancy. A single fault in an active component (thrusters, generator, remote control valves etc.), should not lead to loss of position. Failure in a static component (pipes, cables etc.) can lead to system failure.
- **DP Class 3 (DP3)-** Redundant and separated components. A single failure should not lead to loss of position. System to withstand water flooding or fire in compartments/rooms.

(Redundancy provides operational safety if one system was to fail).

A GPS is usually the positioning system used for monitoring the vessels position, heading and speed. Wind sensors detects both speed and direction of the wind. When on location, the acoustic beacons (special sensors) are placed on the sea floor to coordinate with the satellite GPS signals. Weather, wind and current information's are also implemented in the computer system for movement control. The computer system then automatically responds to the information and GPS signals, and calculate the required thrust to stay in the desired position. Further, the computer system will automatically employ the thrusters to compensate the acting forces.[35, 38]

DP systems can supplement the mooring system, or fully replace it. Posmoor-ATA (automatic thruster assisted) is a mode used when the DP system works together with the mooring winches. By taking advantage of the automated computer system, the thrusters can assist in tension reduction of the mooring lines. Additionally, the system can assist the anchor winches, monitor the mooring pattern and compensate for line breaks. It is favourable to make use of the DP system during deep water operations, for congested seabed's and during batch drilling operations. Relocation might be due to operations in the same area or threatening storms.[38]

4.3.1 GREEN DP

Kongsberg Maritime Group has developed a greener DP system, called "Green DP control". This new system is a part of their "Green Ship Strategy", and can lower a vessels fuel consumption with up to 20%. Saving both costs, and reducing the CO^2 emission. As for standard DP system, the green DP system is used for station- keeping of the vessel. But instead of acting on present conditions, the green DP system is predicting the vessels movement due to the external forces. To forecast the vessel's motion, the system is based on a so called 'nonlinear model predictive control'. Which optimises the thruster power and the predicted dis-location of the vessel by filtering out the minor disturbances. More precisely and accurate disturbance detection provides a smoother control, lower peak loads and an extended lifetime for the thrusters. The Green DP system has so far only been implemented on ships, but has the potential to improve fuel consumption if used on floating rigs.[40]

4.4 ADVANTAGES AND DISADVANTAGES

As mentioned, DP system can be favourable over the mooring system in deeper water, for congested seabed's, and whenever frequent relocation is required. It has therefore been assumed that the mooring system is best suited in shallow waters and for long-term operations. The time frame for a 'long-term operation' with regards to station keeping systems, are not clearly stated in previous literature[41]. A report from the Toutatis project quantified the best option for that particular project, and the results can give a better understanding of the time frame (Ch 4.5 DP vs. Anchor on West Hercules).

Choosing a DP system eliminates the need for mooring lines, AHV and the whole anchor handling process (less time and resource consuming). Listed below are the main pros and cons with regards to choosing the DP system over the anchoring system:[38, 40, 42, 43]

Pros of using DP system instead of anchors:

- No pre-lay operations, less time and resource consuming. Can start the operation shortly after arriving on location.
- Avoids the possibility of wire chain failure or winch failure, which can lead to an uncontrolled state of the rig.
- Ability to position the rig to lead the exhaust away from the deck (better work environment).
- Can operate in ultra-deep waters offshore, where mooring lines cannot be installed.
- Able to quickly disconnect and change location in case of emergency or bad weather (increased safety).
- No interference with or damage to the seabed and coral reefs, existing pipelines, fishing gear, mooring lines from other vessels or subsea structures (manifolds, risers, wellheads etc.).

- Possible to optimize the rig's heading during loading and unloading from supply vessels.

Cons of using DP system instead of anchors:

- Higher fuel consumption during operation, active system running 24/7.
- Not optimal in shallower water.
- Severe danger in case of equipment failure which might lead to a complete system failure. (Especially during critical operations close to fixed platforms or during pipe-laying).
- Drift-off due to errors in the thruster system or DP sensors. During drift-off events the riser becomes the mooring point for the vessel, which can lead to damage on the well/BOP/riser if the rig is not able to disconnect fast enough.

4.5 DP VS. ANCHOR ON WEST HERCULES

4.5.1 SCOPE OF THE REPORT

To find the best suited station-keeping system for a specific operation, one would need to consider expenditures, rig capacities, location, and the environmental impact. As stated, the DP will require more fuel during operation than the anchoring system. But, for the Toutatis well, all options affecting the operation and environment were evaluated extensively. Hence, it was decided to make an extended assessment on the station keeping method on West Hercules. Global Ocean Technology (GOT) was requested to evaluate DP vs. Anchor as station keeping method during the Toutatis operation. Site survey on location showed no marine hazards or sensitive habitats, which could have limited the use of anchors[39].

The main criterions for the DP vs. Anchor report was:

- End result must be an unobtrusive, objective, fact- and knowledge- based report. Taking into consideration the environmental concerns for this specific area.
- Not to include recommendations, well team to make their own assessments based on the report.
- Any anchoring event must include relevant environment and safety considerations.

4.5.2 STATION KEEPING ON WEST HERCULES

West Hercules is equipped with DP Class 3 (Kongsberg Maritime), with a thruster force of 3.6 m/s (7 knots). In addition, it uses Posmoor- ATA (Kongsberg Maritime) on anchor mode. The mooring system onboard consist of 8 mooring lines (8 x 1700m 84mm chain) and 4 double Pusnes 450kW winches. A minimum of 200 m water depth is required for the existing DP system to function within the set requirements and specifications[39].

4.5.3 PHYSICAL CONDITIONS

The planned spud date for Toutatis was 1th of September 2019. Wind, wave and current data was taken from the Metocean report that was specifically made for the Toutatis location. The currents on the Toutatis location was physically measured before included in the Metocean report. By evaluating the expected environmental factors, one could decide if the conditions would be within the operating limits for West Hercules. Both wind, current and waves for September was well within the operating limits[39].

4.5.4 FUEL CONSUMPTION

The following assumptions and data were used to compare the average fuel consumption between DP3 and Posmoor-ATA[39]:

- DP mode consumption: 40 m^3/day (from Seadrill)- (drilling operations day - day)
- Posmoor consumption 37 m^3/day (experience data from Equinor operation) - (day-day drilling operations)
- For Pre-lay (PL), Transit (Tr), Connection (OK), Disconnection (Nk) is a type KL Saltfjord AHTS used - economy speed consumption 22 m^3/day - working average 25 m^3 /day
- Anchor handling (AH) operations and normal duration time;

  o AH for pre-laying: 3+4+3=> 10 days

  o AH for connection: 6+2+6=> 14 days

  o AH for disconnection: 6+2+6=> 14 days

  o AH for pick-up and demobilisation: 3 days (only pick-up and deliver)

Activities	DP Fuel Consumption (m^3)	Posmoor-ATA Fuel Consumption (m^3)
Pre-laying (10 days)	-	250

Transit (0 days)	-	-
Connection (14 days)	-	350
Drilling Operation (30 days)	1200	1110
Disconnection (14 days)	-	350
Anchor pick-up and demob. (3 days)	-	75
Total estimated diesel consumption	**1200m³**	**2135m³**

Table 4: Estimated diesel consumption for West Hercules on DP vs. Anchored.

Table 4 and Figure 12 are graphically illustrating the estimated fuel consumption for the Toutatis operation. Looking at the operational time alone, DP mode would burn up to 90m^3 more than the anchoring solution. By including all AH operations in the evaluation, it is clear that DP mode would result in a considerably lower emission. No need for AHV's and AH time turns DP mode into a better solution. Despite the fact that DP mode consumes more fuel than the anchoring during operation (around 3-4 m^3/day).

For the operation as a whole, the decreased fuel consumption from DP over anchor is 935m^3. Combustion of 1L of diesel (0.88kg) creates about 2.68kg of CO_2. Thereby, 1m^3 of diesel consumption is equivalent to approx. 3.17m^3 of CO_2. Choosing DP mode would thereby eliminate up to 2964m^3 of CO_2 emission.

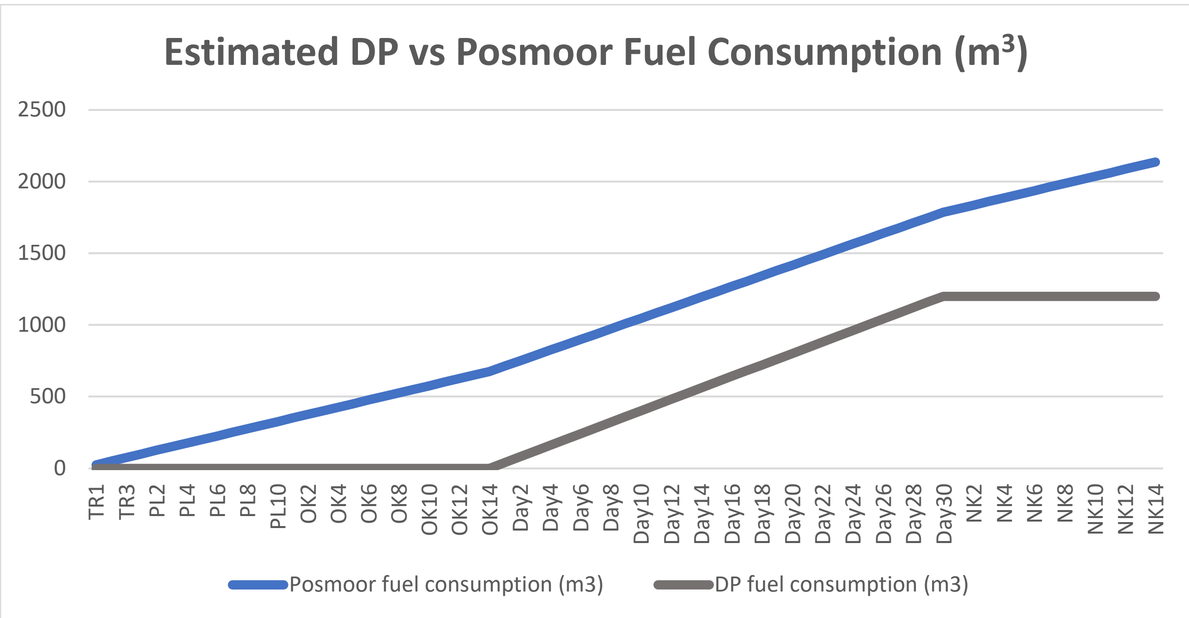

Figure 12:Estimated fuel consumption on DP vs. Anchor for West Hercules.

4.5.5 RESULTS ANS DISCUSSION

As a result of several evaluations, it was decided to make use of the DP system as the primary station keeping method on Toutatis. The conclusion was drawn with regards to a lower environmental impact from DP (both seabed disturbance and emission to air), and was primarily based on:

- DP vs. Anchor report from GOT. DP the best suited choice (seabed, emission to air).
- Toutatis Metocean Report. Expected weather conditions well within operating limits for West Hercules on DP3 (wind, current and waves).
- DP3 on West Hercules has been used as primary system for station keeping during drilling in the Barents Sea, with good results (in water depths as low as 300m, 67m shallower than the water depth at Toutatis).

Even though the spud date was delayed until the end of October 2019, the savings from DP were still significant. The actual diesel consumption for Toutatis was 1230 m^3, with a daily average of 41 m^3/day. Just slightly above the estimated value for DP mode (1200 m^3). Hence, a total saving of 905 m^3 of fuel and approx. 2868 m^3 of CO_2 as illustrated in Figure 13 below. This was well within the permit for emission to air as shown in Table 5. Deciding on DP as the station keeping method lowered both the carbon footprint and environmental impact. In addition, the reduced diesel consumption helps lowering the operational costs as well.

	CO2 (m^3)	**NOx (m^3)**	**nmVOC (m^3)**	**SOx (m^3)**
Permit for fuel consumption	4184,4	68,64	6,6	0,132
Actual fuel consumption	3899	63,96	6,15	0,123

Table 5: Permit for emission to air vs. actual emission from fuel consumption (Toutatis, 30 days).

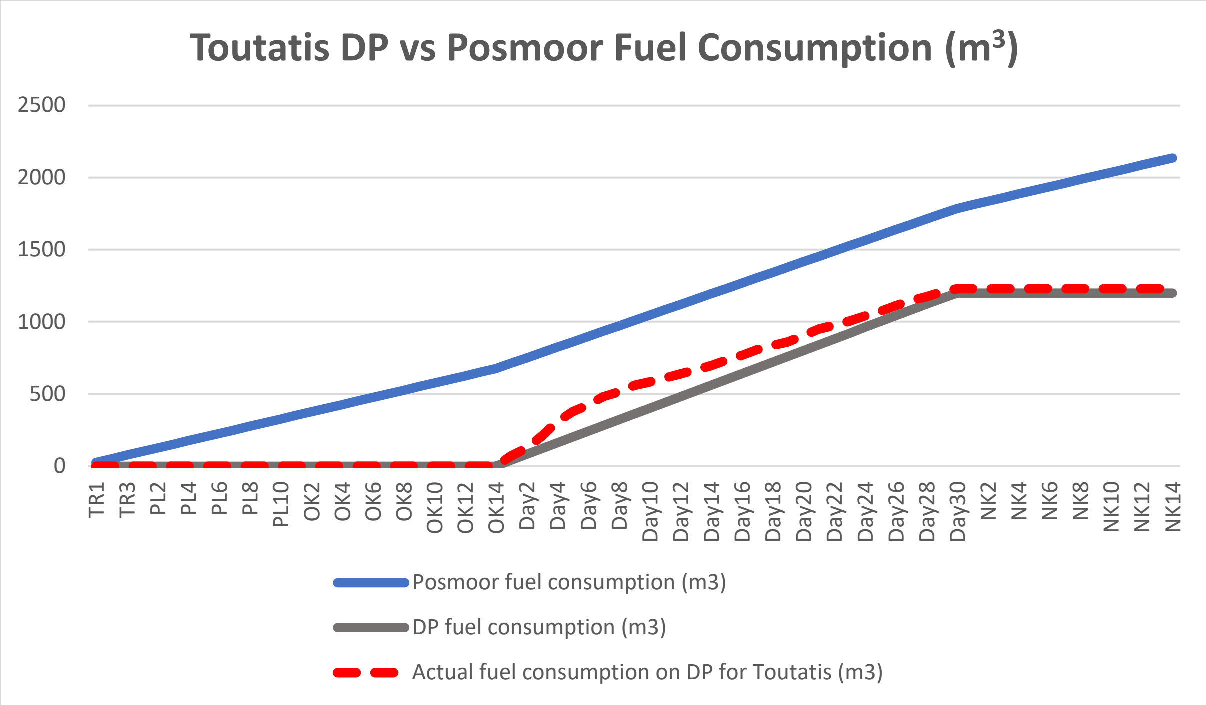

Figure 13:Estimated vs. actual fuel consumption for West Hercules on Toutatis.

The Toutatis exploration well was operating for only 30 days, but made a clear saving from being on DP mode. By using the average values from the report, one can estimate at which point the trend shifts. Figure 14 below shows almost no difference in fuel consumption between operational day 200-240. With that being said, these numbers are based on weather conditions in September. During winter months the weather tends to get rougher, hence increasing rig movement and fuel consumption. To leave a margin for these conditions, it was estimated that the Toutatis operation could last for approx.100 days, and still benefit from DP. To make these numbers more exact, weather data for the winter months would need to be implemented. Since the maximum estimated duration for the Toutatis well was 35 days, evaluation on a possible extension of the operational time was not included in the scope of this report.

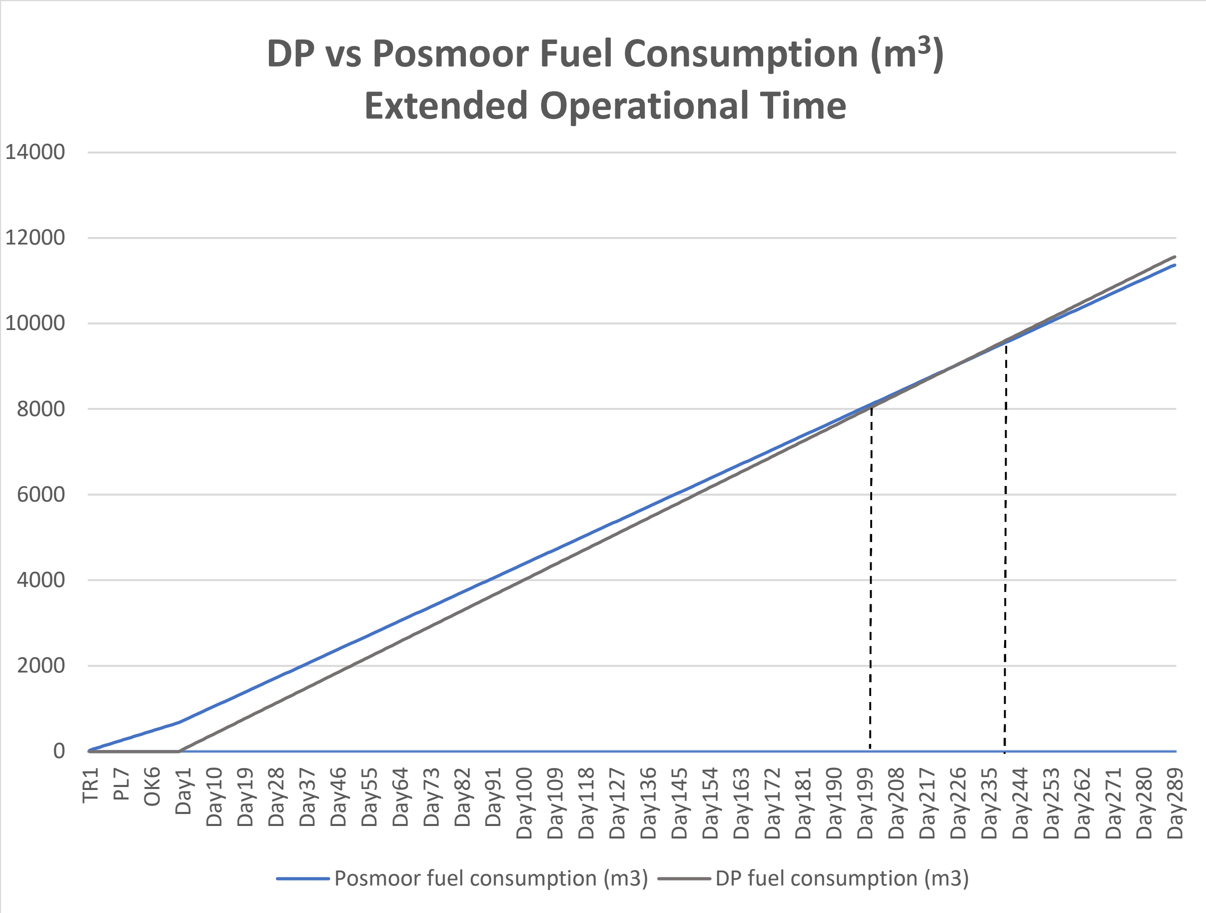

Figure 14: Estimated fuel consumption on DP vs. Anchor on West Hercules (Extended operational time).

5 GREENER DRILLING RIGS

Choosing the right drilling rig for an operation is one of the most important elements in well planning and design. The rig rates are often a large part of the total project cost. With day rates up to 600 000 USD for an offshore drilling rig (at peak in 2013). Main factors affecting the day rate are the rigs classification, drilling depth capacity, lead time and length of the contract. Not only is it expensive to hire a rig, more rig days requires more fuel and hence increased emissions. [44, 45]

Offshore drilling rigs have developed over the last decades to become smarter, safer and more automated. Now rig operators are experiencing a demand for even greener and more energy independent rigs. Making the operators looking to boost automation while lowering their carbon footprints. This has, among other, led to an interest in developing hybrid power solutions for offshore drilling rigs. [46]

Seadrill is one of the offshore drilling rig operators that have focused on new power methods and greener technology. Recognizing themselves by 'setting the standard in offshore drilling', with a sustainable business approach. As per today they own 35 drilling rigs, and manage 18 rigs on behalf of Seadrill Partners, Seamex and Northern Drilling. They are operating all over the world, and have several rigs operating on the NCS. With a modern fleet they are able to operate in harsh and benign environments. Two of their rigs worth mentioning is West Hercules and West Mira, and additional info on these can be found below.[47]

5.1 WEST HERCULES

West Hercules is a warm, 6. Generation semi-submersible 'Green Rig'. It can operate in water depths up to 3000 m, and have a maximum drilling depth of 10'670 m. A warm and green rig refers to it being a fully winterized and contained rig. Constructed for a 'Zero unplanned discharge operation' in cold and harsh environments. If a spill of chemicals occurs on deck, the slop and water is then collected in tanks onboard the rig through a drain system on the deck. The slop is then treated on the rig with dedicated cleaning equipment or sent to shore for further treatment. This is significantly reducing the risk of unintentional spill to sea.

Figure 15: West Hercules. @Seadrill

As mentioned earlier, West Hercules was chosen to drill the Toutatis well. A decision made due to its features and experience from operating in the Barents Sea, another environmental sensitive area. Including a tuned and well-trained crew with a high focus on safely executed operations.[48]

5.2 WEST MIRA

West Mira is sixth-generation ultra-deep water semi-submersible rig from 2018. At the end of 2019, West Mira was upgraded and became the world's first hybrid-powered offshore drilling rig. A major stepping stone for both Seadrill and the drilling industry towards a greener conversion. For this project Seadrill have worked with Northern Drilling, Siemens, Kongsberg Maritime and DNV GL for development and testing of the system. The final result was made possible by implementing battery storage technology onboard the rig, alongside with the diesel-fired generators. Making it possible to draw power from both diesel motors and the battery package. The battery storage is recharged by the use of diesel-electric generators, and will be used for power supplying during peak load times. During an emergency the battery storage will serve as a backup to prevent blackouts and provide power to the thrusters. For West Mira as a hybrid, it is estimated that the need for the rig's diesel engines can be lowered with up to 42%. While cutting the carbon dioxide emission by 15% and reducing the nitrogen oxide emission by 12%. [49] [50]

5.3 MAERSK INTREPID

Maersk Drilling is another rig operator that has planned to modifying one of their rigs into a hybrid, low-emission rig. Maersk Intrepid is originally a jack-up rig, designed for ultra-harsh environment in the North Sea. The last year it has undergone what they call a 'low-emission upgrade', in a three-step package. A package which includes hybrid power, Energy Emission Efficiency (EEE) software and Selective Catalytic Reduction (SCR) systems. Hybrid power being the same concept as previously described, with battery packages which reduces the need for engines. The EEE software from Maersk Drilling itself, makes use of real-time data to monitor the rigs energy consumption. Unnecessary use of energy is then detected and eliminated, reducing the overall energy use on the rig. SCR system is introduced to reduce the NOx emission by capturing and treating the rigs exhaust with ammonia, turning the NOx gas into nitrogen and water. By installing this system on the engine exhaust pipes on their entire fleet, they expect to lower the companies NOx emission with 90% or more.[51]

5.4 "RIG FOR THE FUTURE"

Both Seadrill and Maersk Drilling are just two examples of rig operators that works together with the oil industry to lower the emission rates. Although their new hybrid packages are still not fully tested and evaluated, measures such as no spill and energy optimization has proven to lower their emission. Implementing already existing onshore emission savings, needs room and space on the rig. Solar panels, wind mills and more automation.

The "rigs for the future" is a consept study by Equinor to initiate the rig industry to develop even more environmently friendly. rigs might require less crew onboard due to robotics technology, automation and digitalization. Lowering both operation costs and carbon emission. One example is Oceaneering which are testing out having onshore personnel operating and inspecting their remotely operated vehicle (ROV), instead of offshore ROV pilots. Making need for offshore personell only during maintenance or repairs. [52-54]

6 TOUTATIS CASE STUDY

The Toutatis exploration well (6611/1-1) was drilled late 2019 by West Hercules, on contract for Wintershall Dea and partners Equinor, Lundin and Petoro. Spud date was originally planned for 1st of September 2019, but had to be postponed due to delays in the rigs schedule. Toutatis was located on Production License PL 986 on the NCS, approximately 160 km south west of Bodø and 7 km south of the Træna reef. In short distance from the well known Lofoten area. The primary target was to test the HC potential in lower Jurassic Tilje and Åre sandstone formations, estimated to be between 1500 m and 1700 m MSL. [55]

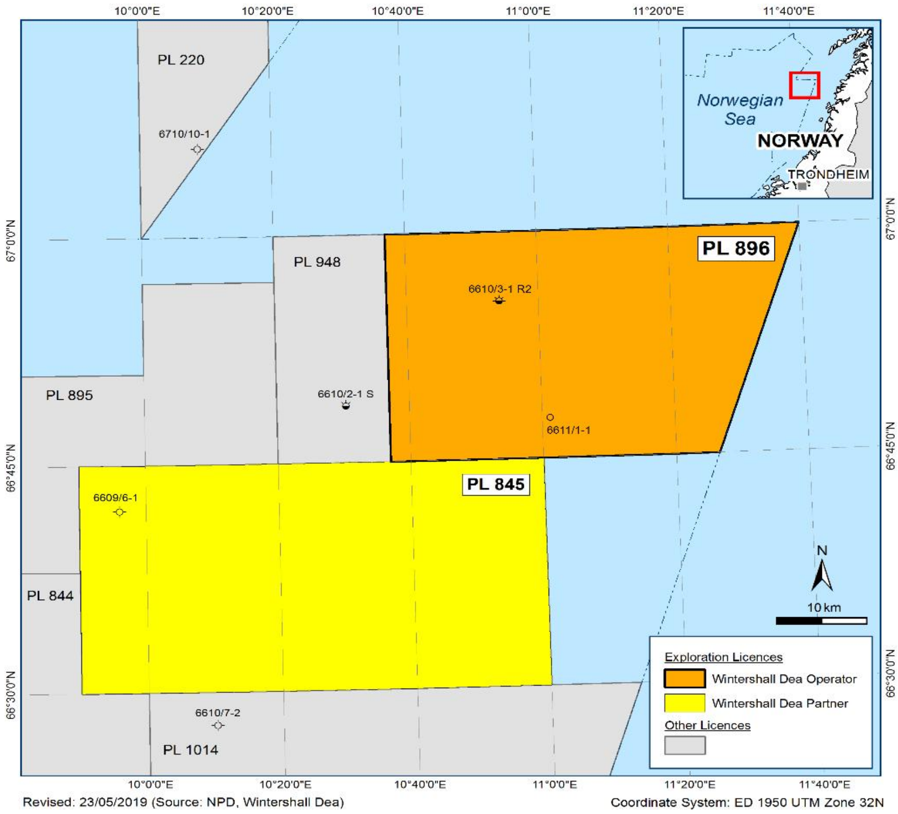

Figure 16: Toutatis (6611/1-1) and license map. @Wintershall Dea

Being located close to this environmentally sensitive area lead to a high level of environmental focus from the beginning and throughout. Setting a high environmental standard for the whole planning and execution phase on Toutatis. Some of the main risk and emission reduction measures implemented in the project was:[55]

- Well and fluids design with a lower environmental impact.
- Contained rig with experience from environmentally sensitive areas.
- Extra measures for detection of spills.
- Environmental coaches offshore.

- Communication resource embedded in the project.
- Workshops and risk assessments including partners, rig crew and service providers.
- NOFO system on standby vessel at location during operation.
- Additional measures to establish a sufficient emergency preparedness during operation (located out of range for the existing SAR area emergency support).
- Increased HSEQ focus (Health, Safety, Environment, Quality).
- Implementing an onshore rig planner as a part of the well delivery team, starting three months ahead of the planned spud date.
- Drilling to be commenced between 1st of September to 1st of January (outside the spawning period for fish).
- Liquid additive system (LAS) for controlling cement chemicals, provides good accuracy and controlled chemical consumption.
- Detailed site survey and ROV inspections of the seabed (radius of 500 m around spud location).
- Reporting and experience transfer internally and externally before and after the project

6.1 PLANNING WITH FOCUS ON HSEQ AND COMMUNICATION

Additional time was added into the well delivery plan for HSEQ aspects. Including more time spent on HSEQ deliveries for the AfD and AfC applications to the authorities. A dedicated HSEQ advisor was actively participating in workshops and meetings, as a part of the well delivery team. With his main focus on:[55]

-Ensure compliance to rules and regulations.

-Maintain high focus on safety in planning phase and during operations.

-Increased focus towards environment at well location.

-Ensure existing best practices onboard West Hercules are followed during operation.

Another important aspect was the political side when it comes to drilling close to an environmental sensitive area. Even if no sensitive habitats or corals was found nearby the well location, it was still a risk for spills and potential blowouts to occur. Which would have had the potential to harm the Træna reef and marine life in Lofoten if not sufficiently handled. Awarding out licenses to drill in the Lofoten area has therefore been strongly discussed and debated during the last decades. It was therefore expected to get increased media attention and reactions from the NGO’s (Non Governmental Organisations) when it was decided to drill Toutatis. To address this properly, a communication advisor worked closely with all parties involved to ensure good communication and to raise awareness, internally in Wintershall Dea and externally. Like the HSEQ advisor, the communication advisor was also a part of the well delivery team throughout the hole planning and execution phase.

A lot of time was spent working with the local authorities to address their concerns by providing them with information on the project. Including meetings and information to the local committee for acute pollution, to inform about the oil spill response plans. Additionally, the well delivery team and management participated in oil spill response drills, local conferences and in meeting stakeholders in the planned operation area. Including a meeting to Røst during the well planning phase. An audit request from the Norwegian Environmental Agency (NEA) was received prior to the operational start, and commenced as a two day visit on the rig during operation.

6.1.1 WELL DESIGN OPTIONS

Toutatis was planned as a vertical well with an inclination < 5degrees. The criterias for the TD was to drill through the Jurassic/Triassic transition, and having the TD 200 m below the Base Båt Group (aproximaely at 1812 m). This would allow a full evaluation of the Åre formation and upper Triassic. The TD for the well was initially set to 2012 m TVD, and during operation changed to 1905 m TVD. The pressure prognosis for the well in Figure 17, was based on pore pressure measurements and LOT/FIT from the nearest offset wells. The offset analysis forms the base case for the casing and MW options, and stated that the well could be done by a relatively slim well design following a 3- string model. With a casing before the pressure build up at approximately 900 m TVD (before entering the potential sandstone layer), and another casing/liner before the pressure drop at 1300 m TVD (two times the uncertainty above the top Tilje reservoir). None of the offset wells had experienced problems related to shallow gas, or any other shallow hazards. Only minor boulders were mapped out by the site survey, and not expected to affect the operation.

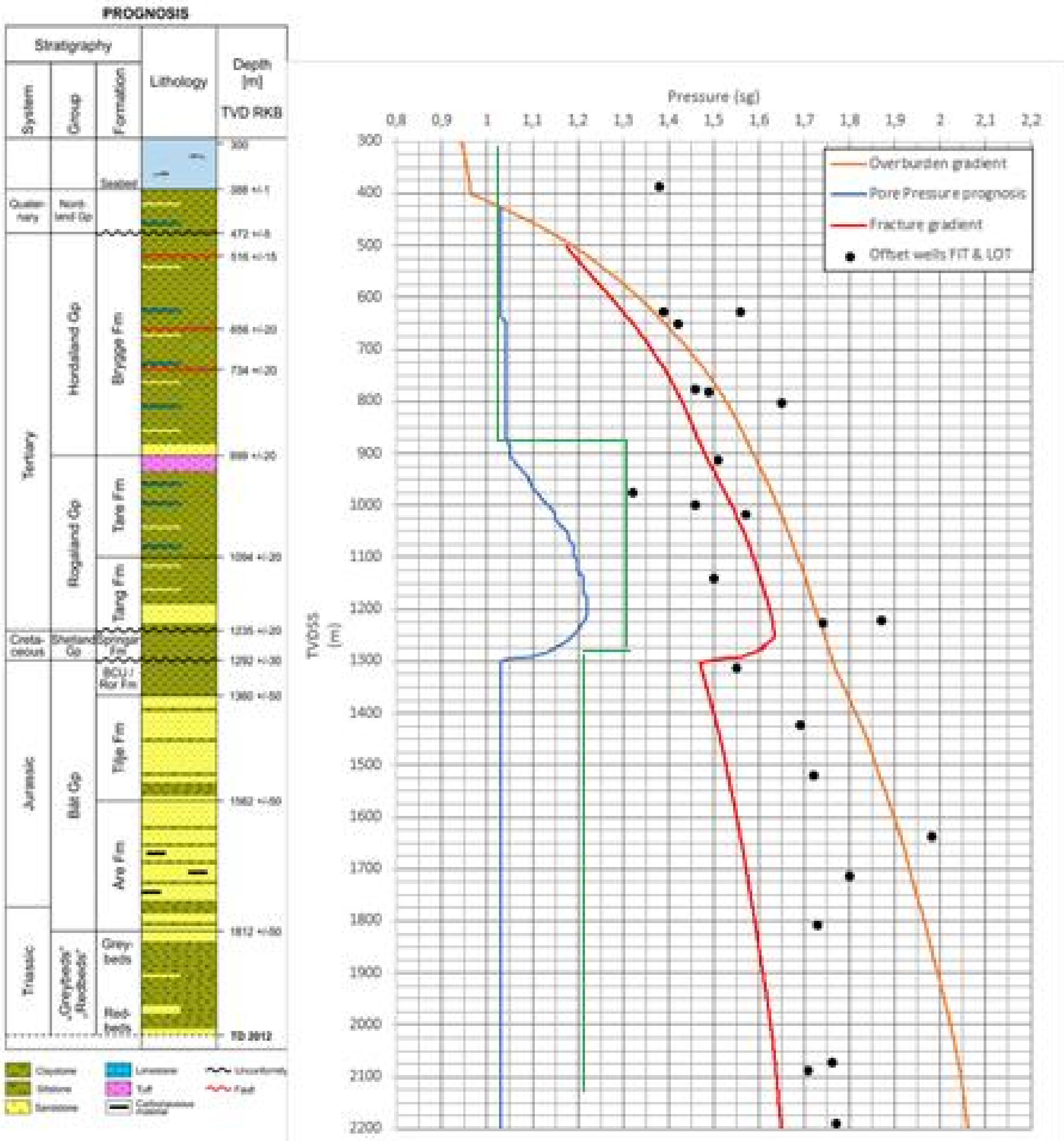

Figure 17: Pressure prognosis for Toutatis based on offset wells, with formations and depths. Green line indicates the mud weight (MW) and casing placements for Toutatis. @Wintershall Dea

A total of 5 different well designs was evaluated in the casing selection process. One of which were for contingency purpose if one were to encounter shallow gas/drilling challenges. All casing designs followed the guidelines and requirements from the NORSOK D-010 Rev. 4 standards, including well barriers. The options are illustrated in Figure 18, and listed below:[56]

#1 – Base Case consisting of a standard 3 string design**:**

- Starting with a 36'' top hole section and a 30'' conductor cemented to seabed, with a 18 ¾'' HPWH on top.

- Followed by a 17 ½'' section to 885 m MD, cased off with a 20'' x 13 3/8'' casing, and cemented to seabed.
- Next a 12 ¼'' section cased off with a 9 5/8'' liner to 1260 m MD, cemented 200 m MD above the liner shoe. (9 5/8'' liner hanged off in the 13 3/8'' casing).
- Followed by a 8 ½'' open hole section to target depth at 2012 m MD.

#2 – Conservative case consisting of a standard 3 string design**:**

- Starting with a 36'' top hole section and a 30'' conductor cemented to seabed, with a 18 ¾'' HPWH on top.
- Followed by a 17 ½'' section to 885 m MD, cased off with a 20'' x 13 3/8'' casing, and cemented to seabed.
- Next a 12 ¼'' section cased off with a 9 5/8'' casing to 1260 m MD, cemented 200 m MD above the casing shoe. (9 5/8'' casing hanged off in the HPWH)
- Followed by a 8 ½'' open hole section to target depth at 2012 m MD.

#3 – Slim case consisting of a lean 2 string design, with a longer 8 ½'' open hole section**:**

- Starting with a 36'' top hole section and a 30'' conductor cemented to seabed, with a 18 ¾'' HPWH on top.
- Followed by a 17 ½'' section to 885 m MD, cased off with a 20'' x 13 3/8'' casing, and cemented to seabed.
- Followed by a 8 ½'' open hole section to target depth at 2012 m MD.

#4 – Contingency Case in case of shallow gas or drilling problems, 4 string design**:**

- Starting with a 36'' top hole section and a 30'' conductor cemented to seabed, with a 18 ¾'' HPWH on top.
- Followed by a 26'' section to 555 m MD, cased off with a 20'' casing, and cemented to seabed (contingency section if shallow gas to be encountered).
- Next a 17 1/2'' section to 885 m MD cased off with a 13 3/8 casing, cemented 200 m MD above the casing shoe.
- 12 ¼'' section down to 1261 m MD cased off with a 9 5/8'' liner, cemented 200 m MD above the liner shoe (9 5/8'' liner hanged off in the 13 3/8'' casing).
- Followed by a 8 ½'' open hole section to target depth at 2012 m MD.

#5 a&b – CAN – ductor system consisting of a standard 3 string design, CAN solution can be used for all 5 design options**:**

- Starting with a 36'' CAN (6 x12,5 m) with an integrated 30'' conductor ,18 ¾'' HPWH system. (Option # 5 a&b refers to Baker Hughes MS-700 WH system or a High pressure swedge from Integrated drilling system). CAN- ductor system to be installed by a vessel prior to spud.
- Followed by a 17 ½'' section to 885 m MD, cased off with a 20 x13 3/8'' casing, and cemented to seabed.
- Next a 12 ¼'' section to 1261 m MD cased off with a 9 5/8'' liner to 1260m MD, cemented over its entire length. (9 5/8'' casing hanged off in the 13 3/8'' casing)
- Followed by a 8 ½'' open hole section to target depth at 2012 m MD.

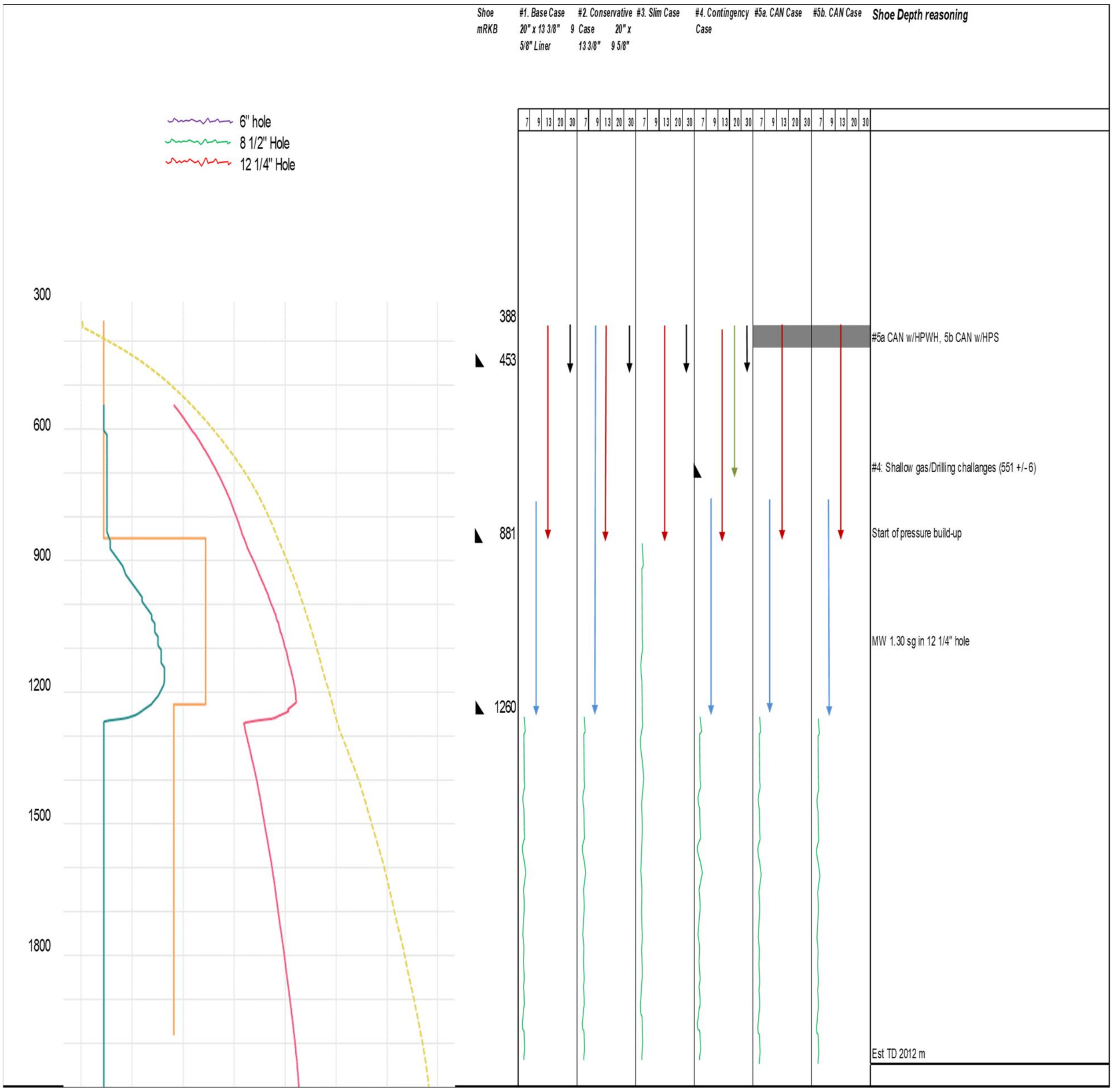

Figure 18: Casing options for Toutatis. @Wintershall Dea

Design 1-4 had the traditional top hole solution, with a 36’’ hole and a 30’’ conductor installed and cemented in place. Some of the cons by choosing these designs was drilling risks associated with tophole drilling, in addition to time-consuming conductor installation and heavy equipment handling compared to the CAN - ductor. Having a 9 5/8’’ liner instead of a 9 5/8’’ casing in the well design gives more flexibility to work the liner and for shoe placement. The 9 5/8’’ casing hanged off in the WH has a very specific placement in the WH, while a 9 5/8’’ liner can be suspended in the 13 3/8’’ casing at different depths. The liner is hanged off in the casing by a liner hanger packer which is then pressure tested. It is crucial that the packer is sealed off properly to avoid any unwanted leakage and pressure control. In addition, installing a 9 5/8’’ casing requires more casing joints and is therefore more time consuming and expensive, due to extra material and running time. Having the 12 ¼’’ section cased off all the way up to the WH provides slightly lower blowout rates than having a 9 5/8 liner. Higher risk off leakage from the liner hanger. The 3 string design options are all a relatively lean design, saving both time and cost. Design #3 was the slimmest design option, with a 2 string design that would have been more optimal in a dry case scenario. The aggressive 2 string design would on the other hand have been more time consuming and expensive in case of a discovery. The pros and cons for the different design options are summarized in Table 7 below:[56]

9 5/8’’ Liner vs Casing	**9 5/8’’ Liner**	**9 5/8’’ Casing**	**Best option**
Blow out rates	Higher blowout rate w/liner	Lower blowout rate w/casing	Casing
Shoe placement	More flexibility	Less flexibility	Liner
Running time and cost	Shorter running time, less rig time and lower expences	Longer running time, more time consuming and costly	Liner
Casing joints required	Shorter distance, less joints required	Longer distance, more joints required	Liner
Hang off point	In the 13 3/8’’ casing, risk of leakage and misplacement	WH	Casing

Conventional vs CAN-ductor	**Conventional well**	**CAN- ductor well**	**Best option**
Installation	More timeconsuming, use of rig days.	Less timeconsuming, CAN installed by a vessel prior to rigs arrival	CAN-ductor
Risks	More hevy lifts due to conductor pipes and associated equipment	Reduces heavy lifts. Eliminates cement problems and cementing personell, No top hole BHA required.	CAN-ductor
Environmental impact	Higher due to more fuel consumption and casing cement and steel	Less environmental impact	CAN-ductor
Time/cost	Requires more rig days and more equipment, hence more expensive	Reduces costs due to reduced rig time and materials	CAN-ductor
3 string vs 2 string design	**3 string design**	**2 string design**	**Best option**
Time/cost	Longer operational time, less cost	Shorter operational time, less cost	2 string
Dry case	Higher environmental footprint	Less environmental footprint	2 string
Discovery case	Less environmental footprint	Higher environmental footprint, sidetrack needed	3 string
8 ½’’ section	Shorter open hole exposure, only one pressure regime	Longer open hole exposure, two pressure regimes	3 string

Table 6: Summarized pros and cons for the main casing design options for Toutatis.

The fluid density specter in Table 6 below, had been evaluated and choosen with regards to riser margin and kick tolerance. The more detailed drilling fluid program was made after the well design selection. With the main idea of using SW with MW close to the pore pressure in the 17 ½'' section, since the cuttings would be disposed to the seabed. Once the riser would be installed one would change to a KCl/Glycol based WBM with a higher density in the 12 ¼'' section. Before lowering the mud density for the 8 ½'' section. The planned mud weights for the 12 ¼'' and 8 ½'' section would not be able to provide a riser margin in the over-pressure shale formation from 900- 1235 m TVD. Since one did not expect his section to have any HC bearing formations with flow potential, it was axcepted. The choosen mud specter was also feasible with regards to the risk of fluid losses. In case of any deviations, the over-pressure formation was drilled with real time pore pressure evaluation as a mitigating action.

Drilling fluid summary				
Hole section	***Base fluid***	***Type***	***Denisty (sg)***	***Comment***
17 ½''	SW	Seawater	1.03	Drilled with SW and hi-vis sweeps. Displace hole to 1,25 sg kill mud at TD.
12 ¼''	WBM	KCl/glycol	1,30-1,35	Displace to WBM before drilling new formation.
8 ½''	WBM	KCl/glycol	1,20-1,25	

Table 7: Drilling fluid summary.

6.1.2 FINAL WELL DESIGN

The final casing design was #5 with the CAN- ductor system and Baker Hughes WH system, illustrated in Figure 19 below. Design #5 had the benefits from a 9 5/8'' liner instead of casing, as well as the benefits from a CAN- ductor instead of running a conventional conductor. Saving both costs, casing material, rig time and cuttings volume. As mentioned, the CAN- ductor system could have been utilized in all the well designs. Regardless, it was evaluated to go with design #5 and having a 3 string model instead of a 2 string. Even if the 2 string model has economic benefits in a dry case scenario, a discovery case with a 2 string model would have required a sidetrack, and hence a higher environmental footprint. In addition, the 2 string models open hole section leads to increased risks by being exposed to two pressure regimes.

The 3 string model was therefore favourable due to the reduced risk and uncertainty compared to a 2 string model. The casing design had been evaluated for all expected worst-case drilling loads to prevent burst, collapse or axial failure.

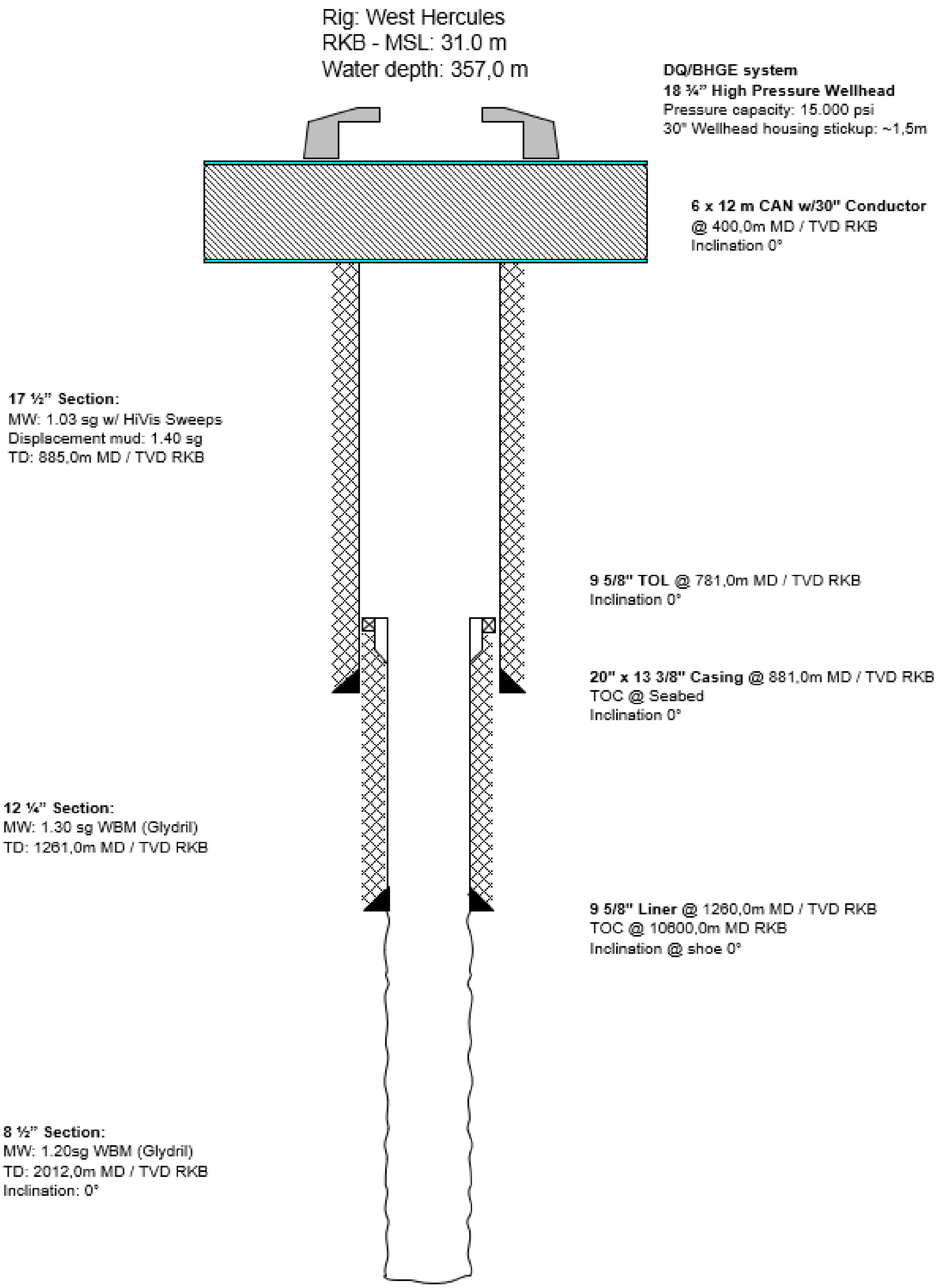

Figure 19: Casing design #5 with a CAN- ductor system, final design for Toutatis. @Wintershall Dea

The planned stages for the final well design were as listed below:

- CAN – ductor to be installed by a vessel in a separate operation, prior to the spud of Toutatis.
- 9 7/8'' Pilot hole +-50 m off location, TD at 885 m TVD. Identify any possible shallow hazards and ensure competent formation to set the 13 3/8'' casing. (drilled with seawater and sweeps).
- Drill a 17 ½'' hole to +-885 m TVD (drilled with seawater and sweeps).
- Run and cement the 20'' x 13 3/8'' casing (cemented up to the seabed). To ensure sufficient integrity for the 12 ¼'' section. Exact casing placement above the potential sandstone layer, prognosed at 899 m +/- 20 m.
- Run BOP and riser, pressure test BOP and 20'' x 13 3/8'' casing/cement.
- Drill out 13 3/8'' shoetrack (seawater and sweeps).
- Displace the well to KCl/Glycol WMB, and perform LOT.
- Drill 12 ¼'' hole to +/- 1260 m TVD.
- Run, cement and pressure test the 9 5/8 liner. Exact depth to be in the Springar formation, +-50 m above the top of Tilje formation which is top reservoir. (cement 200 m above shoe).
- Drill out 9 5/8'' shoetrack and perform LOT.
- Drill 8 ½'' hole to estimated TD at +- 2012 m TVD, cut core in Tilje/Åre formation if HC are identified and performd logging program.

For contingency purposes a conventional conductor was located and available, in case of the CAN – ductor not being installed successfully. As well as sufficient 20'' casing joints in case of shallow gas detection, leading to a section design as in case #4. All casing design options are illustrated in Appendix I.

6.1.3 CHEMICALS

The total usage and discharge of chemicals on Toutatis was well within the permit limits. For the yellow chemicals, only 22% of the AfD approved chemicals amount was used. Whereas for the green chemicals, close to 43% of the allowed amounts were used. This result was mainly due to less drilling fluid, and its low chemical content. The actual volumes are listed in Table 8 below. Without any major incidents during operation, there was no need for contingency chemicals.[57]

Chemical discharges	Yellow chemicals (m3)		Green chemicals(m3)	
	AfD	Actual	AfD	Actual
Drilling fluids	49,3	11,2	554	238
Rig chemicals	2,9	0,3	2,1	1
Cement chemicals	1	0,2	24,6	6,4
TOTAL	**53,2**	**11,7**	**580,7**	**245,4**

Table 8: Overview of the amounts of chemicals discharged from the Toutatis operations.

6.1.4 «TEAMBUILDING»

For this well in particular, it was crucial to communicate the increased environmental focus to all parties involved. The slogan 'Toutatis standard' was therefore introduced at an early stage in this project. A phrase referring to a one team mindset, openness, collaboration and ownership. To gather all involved personnel, the well team hosted several meetings and workshops. Including two 'Drill Well on Paper'' session over two days each, with both the well team, management, service teams and rig crew. Due to Equinor and Lundin's experience from drilling in environmental sensitive areas, Wintershall Dea held several meetings to get their feedback and knowledge into the Toutatis project.

In addition, A reward system was made for the operational part. Consisting of four operational milestones, each one built around performance in relation to the environmental footprint. Reaching a milestone with no unplanned discharged resulted in a price for everyone involved in the project. This included all disciplines onshore and offshore, as well as the whole crew on West Hercules.

6.2 OPERATIONAL PHASE

6.2.1 OPERATIONAL SUMMARY AND RESULTS

West Hercules came on contract the 26th of October 2019, almost two months after the planned spud date due to delays in its current operations. Including mobilization, temporarily P&A and demobilization, the operation was successfully carried out in 29,2 days. With zero waiting on weather and only 6.3% none productional time (NPT). Well within the AFE time of 31 In a dry case. And most importantly, without any accidents, incidents or spills.

A **9 7/8'' pilot hole** was drilled 50 m from location before the main well was drilled. With a TD at 885 m MD, since this was the planned depth of the 17 ½'' section and 13 3/8'' casing. The purpose of this pilot hole was to identify any shallow gas or hazards, and verify competent formation to set the 13 3/8'' casing. And hence ensure sufficient formation integrity of the 12 ¼'' section.

The **CAN – ductor** on the Toutatis project was successfully installed the 5th of June 2019, over 5 months ahead of spud date. From the vessel arrived on location and until the CAN installation was completed, it only took 13 hours. Including installation of the CAN Trawl Protector (CTP). The penetration TD was within target, along with the inclination limit for the WH. Resulting in reduced emissions, a better WH foundation, low WH inclination and less handling of heavy components. The official start of mobilization was 30.05.2020, and ending at 07.06.2020. These 8 days included a 44 hour stop in operation due to crane issues on the vessel, and a one day lessons learned meeting before personnel demob. Giving a total time of 5-6 days during an ideal installation.

Retrieval of the CAN was finished 15 hours from arriving on location. The process included a mechanical cutter together with a hydraulic motor on top of a H4 connector. The cutting tool lands in the WH and establishes stab-connectors before it cuts the 20 x 13 3/8'' casing, 11 m below seabed to free the CAN from the well string. The CAN itself is elevated by pumping water inside, while pulling with the vessels crane at the same time. The vessel came on hire 16th of May 2020, and ended the project on the 23th of May 2020. Resulting in a 7 days retrieval period.

The **17 ½'' section TD** was adjusted to 824 m MD, due to the pressure regime for casing setting depth criterias coming in shallower than expected. Leading to the 12 ¼'' section ended up at 1245 m MD instead of 1261 m to place the shoe in the Springar formation, and not in the sandstone. Having elements as a wildcat well, it was expected to get slightly different pore pressure than estimated from the offset wells. And the depths of the different sections was therefore adjusted accordingly throughout the operation phase. See Apendix II for the final well path.

After setting the **9 5/8'' liner** hanger packer, one failed to get a valid pressure test. After several cleanup runs and changing to the backup liner hanger, a good pressure test was achieved. Meaning that the packer held pressure from above and below. The learning was to always have a casing scraper available for casing cleaning, even if WBM is used.

The **TD of the well** ended up at 1905 m MD in the Greybeds Formation. The only HC encountered was a 9 m oil column in the Tilje formation (Tilje sandstone at 1259 – 1388 m MD). To establish any possible productivity both sidewall coring, logging and samples from the wireline tools was carried out. The well was permanently plugged and abandoned (P&A) after performing all data acquisition and tests program. P&A schematic in Appendix I.

As planned the 17 ½'' section was drilled by using seawater at 1.03 sg, and hi-viscosity sweeps/pills containing Bentonite. A type of clay that swells in contact with water, making the pill more thick/viscous to aid cuttings transport. Returns were taken to the seabed for this section, before running the BOP on the marine riser. The Glydril WBM for the 12 ¼'' and 8 ½'' section ended up within the design spectre, at 1.30 sg and 1.20 sg respectively. Overall, the fluid system performed well, with some adjustment on the KCl and Glycol levels due to reactive clay encountered int the 12 ¼'' and 8 ½'' sections. Leading to a slightly increase in the MW's, but still within the criteria. One of the benefits from using WBM, was the eliminated need to pumping spacer ahead of the cement for the 20''x 13 3/8'' cement job.[58]

6.2.2 ENVIRONMENTAL COACHES

Due to the increased focus on environmental issues it was decided to have environmental coaches offshore to support the operation 24/7. As a part of the mitigating action to reduce the risk of unintentional spill to sea. In addition to focusing on zero spills, they were set to improve the overall safety performance during operation. This included participating in the offshore meetings to increase the environmental focus. Briefing new rig crew at arrival on the zero spill and safety focus.

Focus area for the environmental coaches[59]:

- Assist rig management and the operator in promotion of understanding safety and environmental requirements, systems and procedures among rig personnel and third-party contractors.

- Identify main areas of concern onboard and contribute to find constructive solutions to improve environmental/HSEQ performance.
- Attend, support and where appropriate facilitate: tool box talks, team safety discussion, the identification of the hazards, risks and mitigations for all tasks to ensure common understanding.
- Coach, support and work with the Safety Reps and the rig crew with all relevant initiatives.
- Participate in Risk Assessments and accident/incident investigation both offshore and onshore.
- Continue to further develop and maintain the HSEQ culture onboard the rig.

On a daily basis the coaches would check-up on possible spill points, drains, waste management, lifting operations, housekeeping, barriers. In addition, they were to assist the bridge in detection of spills. This was documented by daily and weekly environmental reports.

6.2.3 DETECTION OF SPILLS

Detection and prevention of possible spills had a high priority. With zero unintended spills as the main focus. Even with a contained rig, and double spill barriers, extra measures were implemented for spill detection purposes. Including a NOFO system installed on one of the supply vessels on location. Even if the potential blowout rates were low enough to not require such a measure. Additional surveillance measures were also made to detect any spill to the sea. Both the rig and the stand by vessel was equipped with hand-held infrared (IR) cameras, in addition to the radar surveillance onboard the vessel. Potential oil spills were documented every hour from the supply vessel. On the rig, a similar IR camera was used for spot checks during dark hours.[55]

6.2.4 SLOP WATER

On West Hercules, the slop water is treated by a Nature Technology treatment unit. This system is a two-stage treatment system, consisting of a decanted and a filtration unit. Slop water from the drains are collected and routed to this treatment unit. Solids and oils are extracted almost completely from the slop water by this system. During the Toutatis operation, a total of 363 m^3 of treated water was discharged to sea. With an average oil-in-water concentration of 1 ppm.

6.3 COSTS

Additional time was added into the well design phase and delivery plan for HSEQ deliveries. Such as submitting applications to the authorities (AfD and AfC), reducing risk, and evaluating more environmentally friendly options. In return all the applications were approved by PSA several weeks before the planned spud date. On the opposite side, the additional workhours resulted in some cost reducing solutions. By using DP, CAN- ductor and less chemicals, the operational expenses came out lower than for the conventional solutions.[58]

6.4 RESULTS AND DISCUSSION

All in all, the Toutatis was a successful exploration well with an increased environmental focus. With a high standard of planning and execution, the majority of all HSEQ targets were achieved. And most importantly with zero accidents, incidents or unintended spills. Made possible by all parties involved, and their willingness to put in the extra time and effort towards lowering the environmental footprint and risk reduction.

The chosen well design resulted in a reduced environmental footprint mainly due to;

- A relative slim well design.
- Safer well design and less rig days due to the CAN- ductor.
- Reduced fuel consumption due to the DP system.
- Less cuttings due to no top hole drilling.
- Less casing material due to a 9 5/8’’ liner instead of casing.
- Dopeless casing from Tenaris.
- Less chemicals and cement volumes.

Although more resources were utilized during the planning and design phase of the well, the operational costs were lower as a result of the selected well design. From a cost perspective solely, one could compare the result of extra planning hours versus operational savings.

7 CONCLUSION

The decisions made during well planning have mainly been focused on safety, cost efficiency and applicability of the design. As the environmental aspect have been getting more attention the past years, environment now needs to be one of the new key elements in any well design process. To ensure that the environmental aspect plays an equal role during decision makings. Even if the governmental regulations require 'zero unintended spills', more environmental requirements towards the oil industry could potentially enhance the environmental focus. Some potential measures are slimmer well design, hybrid rigs, reuse of equipment, less chemicals use and smarter well design options.

With the WH and conductor system as a known 'weak link' in the well design, the smarter CAN solutions from Neodrill provides a better top hole solution. Once installed, the CAN provides less or no risk of fatigue issues, and with a proven inclination < 1 degree. The construction can be installed and retrieved with light vessel before the rig arrives on location, cutting both rig time, cost, fuel consumption and the environmental impact. The report from Asplan Viak, quantifying and comparing a conventional conductor and a CAN – ductor, showed that the main environmental, risk and cost benefits came from reduced rig time and casing material. In total, the rig time was four days shorter for the CAN-ductor compared to that of the conventional technology. Advantages with respect to cost, logistics, transport, and HSE aspects were also found. The CAN – ductor system is therefore recommended to use in environmental sensitive areas.

The GOT report showed that it also would be favourable to use DP in shallower waters for exploration wells, with an operation time up to 100 days. Based on weather conditions in September and for the drilling rig West Hercules. Even if previous reports had stated that it would be more beneficial to choose an anchor handling system for a similar exploration well. During winter months the weather tends to get rougher, hence increasing rig movement and fuel consumption. To leave a margin for these conditions, it was estimated that the Toutatis operation could last for approx.100 days, and still benefit from DP.

One of the main outcomes from the Toutatis campaign, was that spending more time and workhours in the planning and well design phase can be beneficial. With respect to both the economical side, risk picture and environment. Extra days spent on evaluating operational options, can in some cases be justified by the operational and environmental savings from a better solution. Including mobilization, temporarily P&A and demobilization, the operation was successfully carried out in 29,2 days. With zero waiting on weather and only 6.3% none productional time (NPT). Well within the AFE time of 31 In a dry case. And most importantly, without any accidents, incidents or spills.

Changing even the small details in an operation, can have a major impact. As for example the Dopeless casings from Tenaris, eliminating the need for greasing the casing joints. Hence lowering the total casing costs with up to 10%, and at the same time reduce the human risk and environmental impact. Another briefly mentioned potential is reuse of equipment. The can used for the Toutatis well had previously been run on another well. Followed by inspections and new painting. Reuse of this particular CAN was possible since its length and features was suitable for both wells. Resulting in lower use of resources such as workhours, manpower and materials.

APPENDIX I

Casing design options # 1-5 for Toutatis, and P&A program.

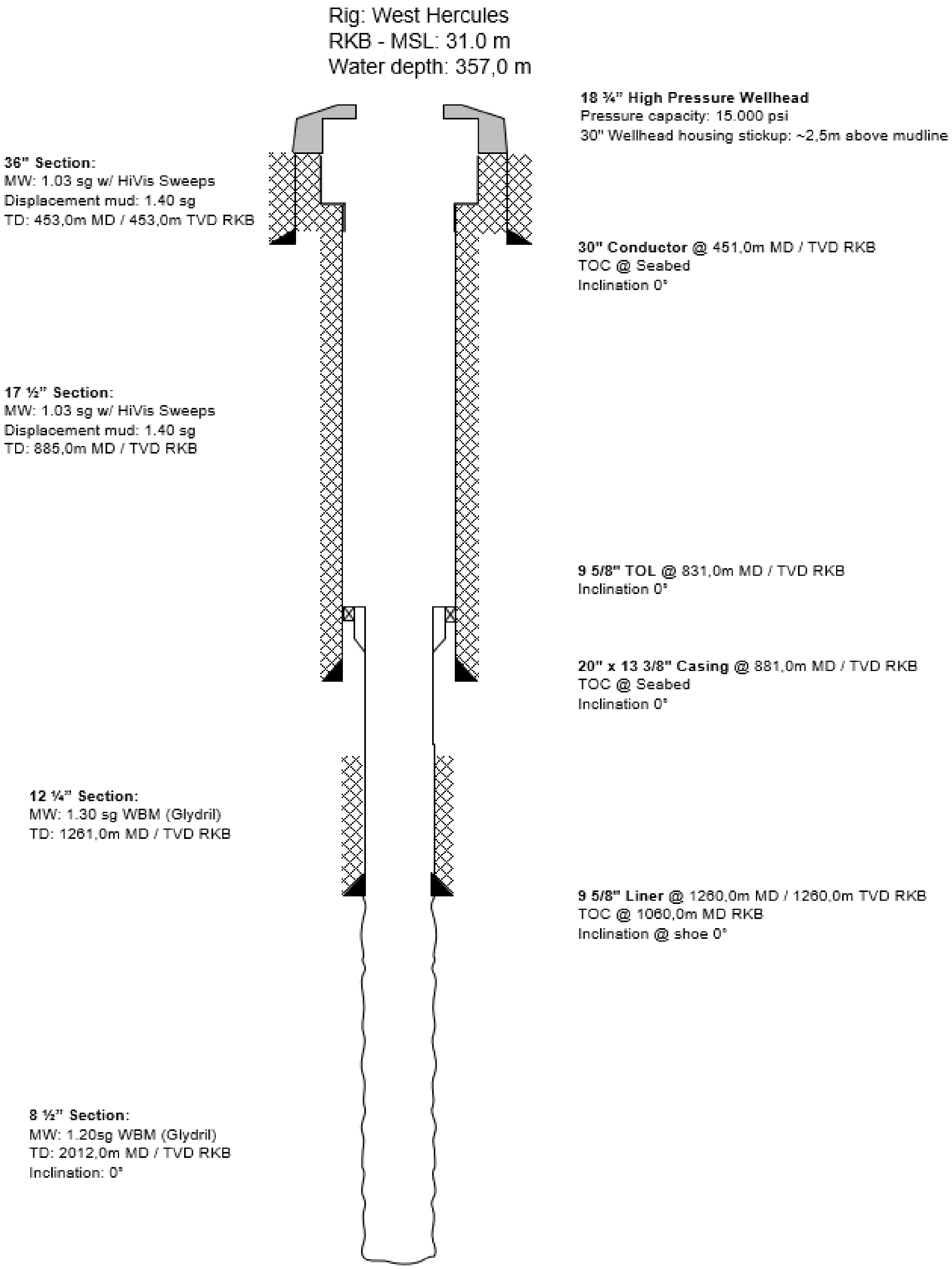

Figure 20: Casing design #1 - Base case. @Wintershall Dea

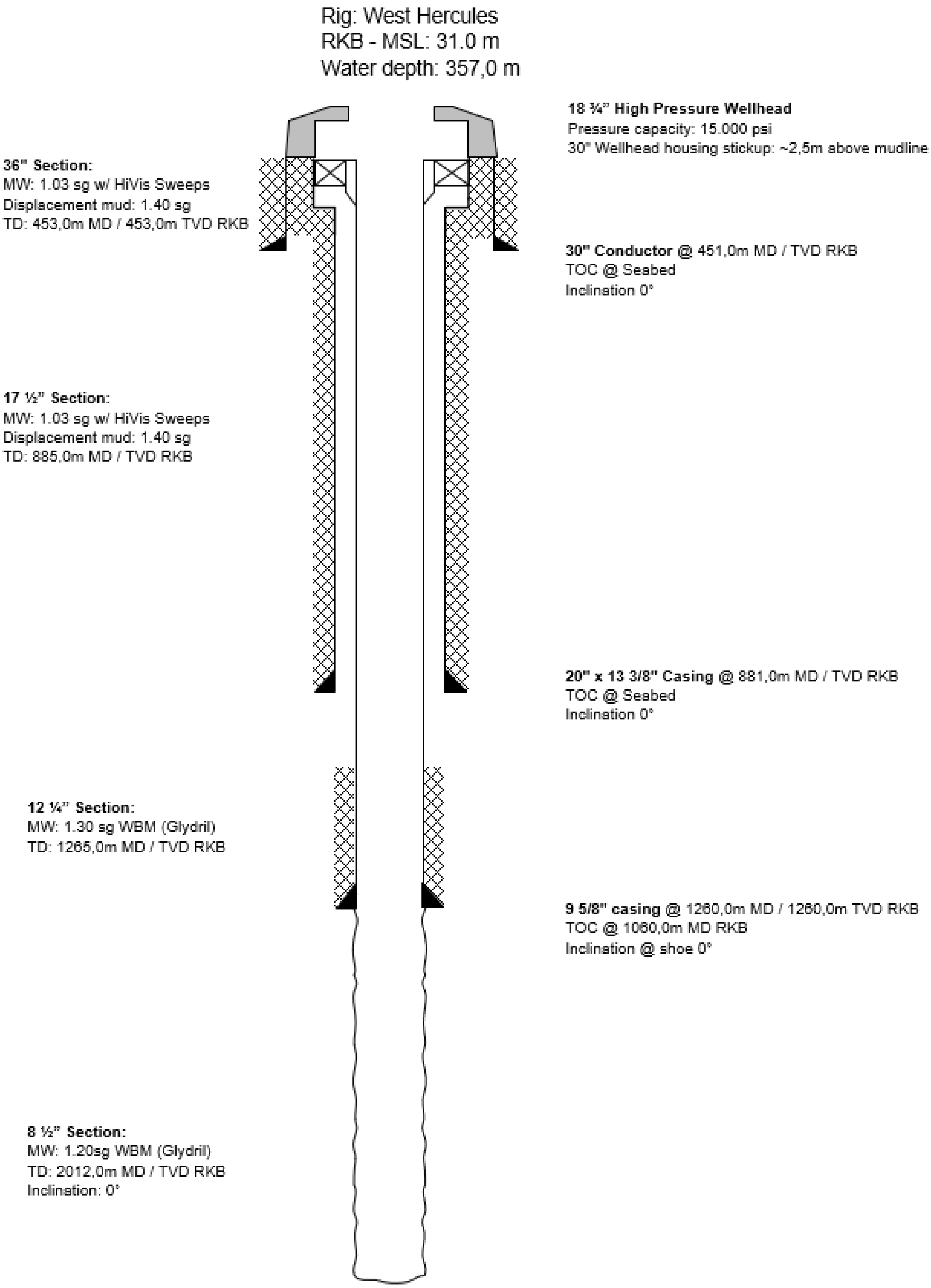

Figure 21: Casing design #2 - Conservative case. @Wintershall Dea

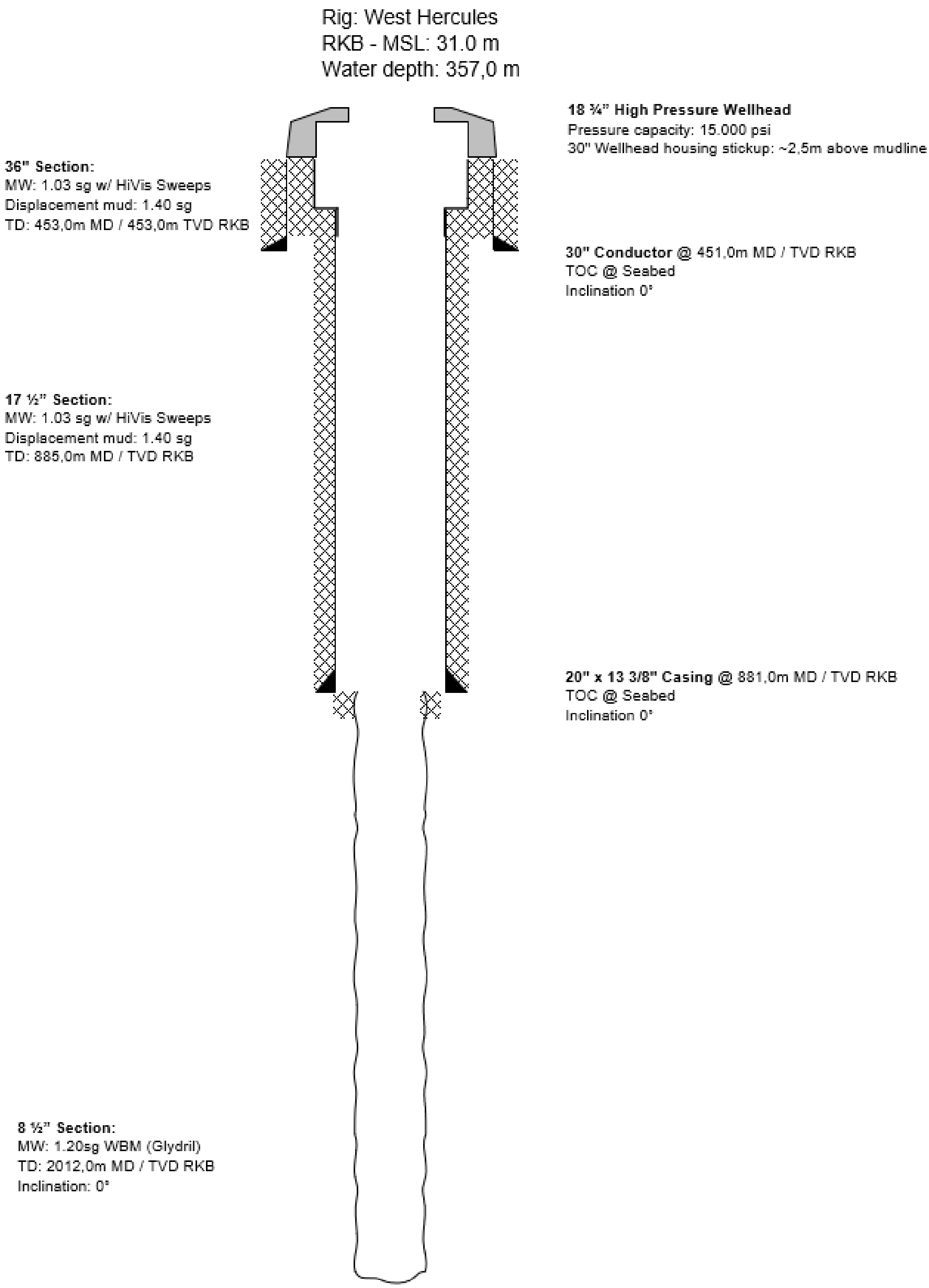

Figure 22: Casing design #3 - Slim case. @Wintershall Dea

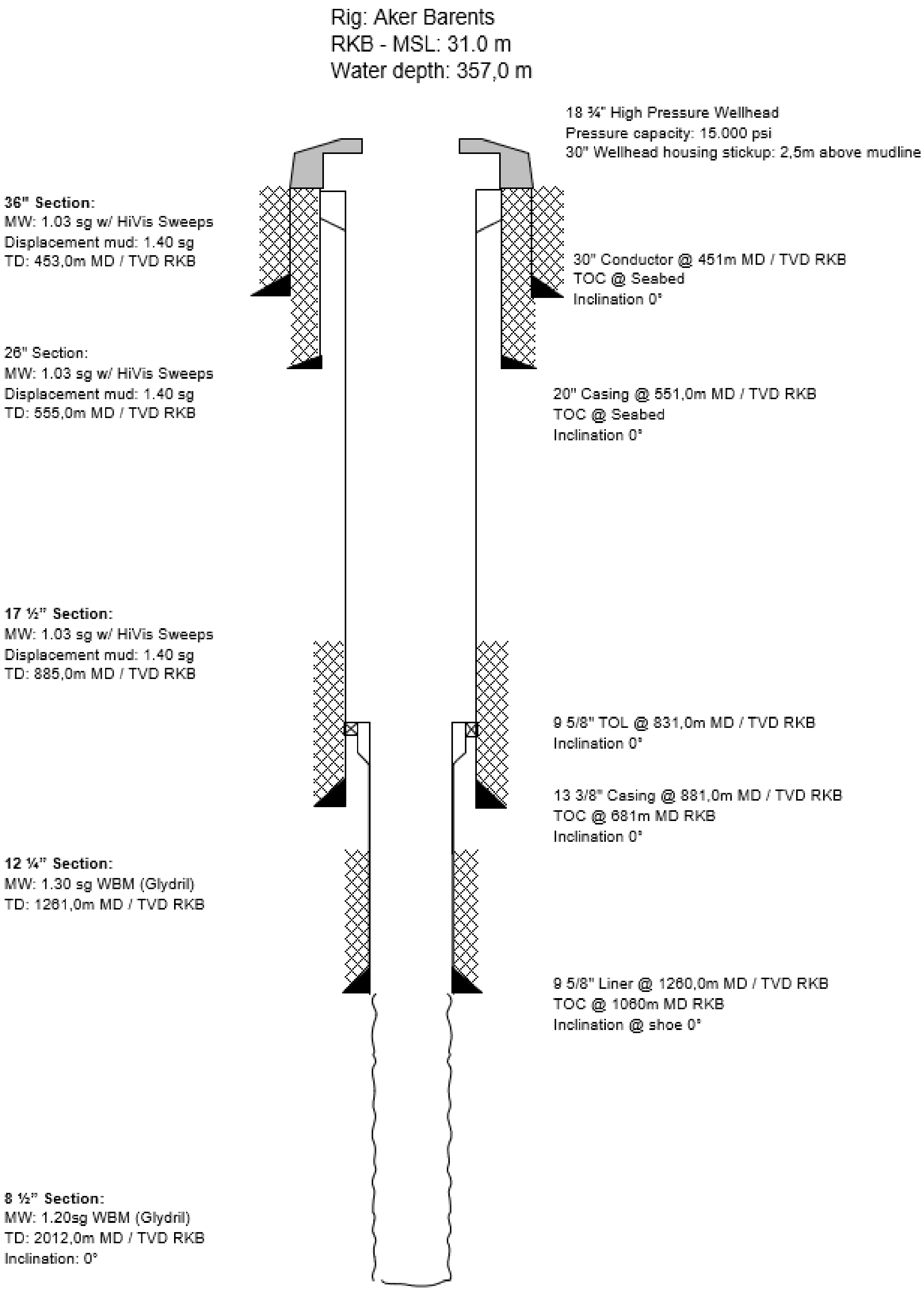

Figure 23: Casing design #4 - Contingency case. @Wintershall Dea

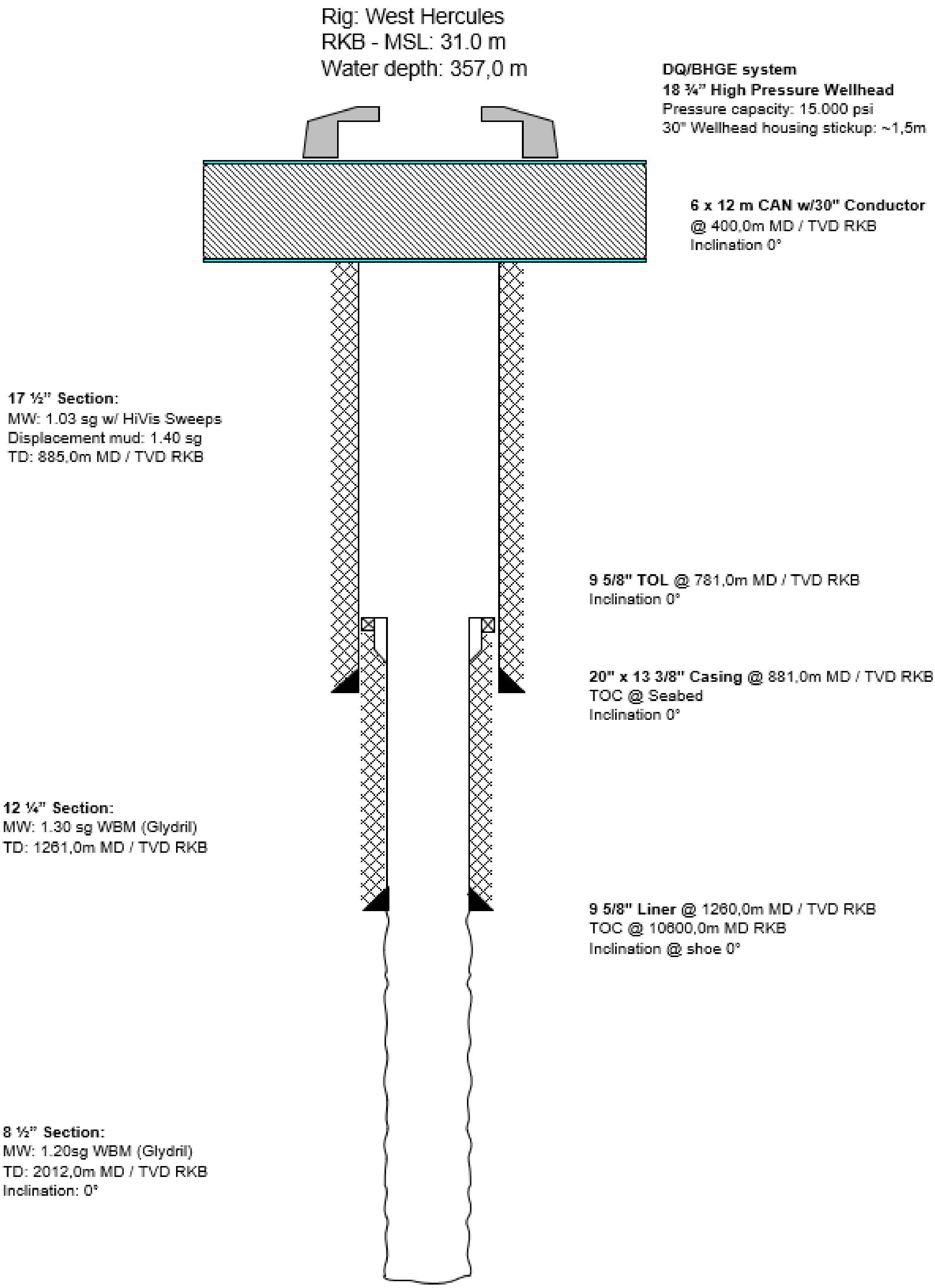

Figure 24: Casing design #5a - CAN- ductor system (BHGE WH system). @Wintershall Dea

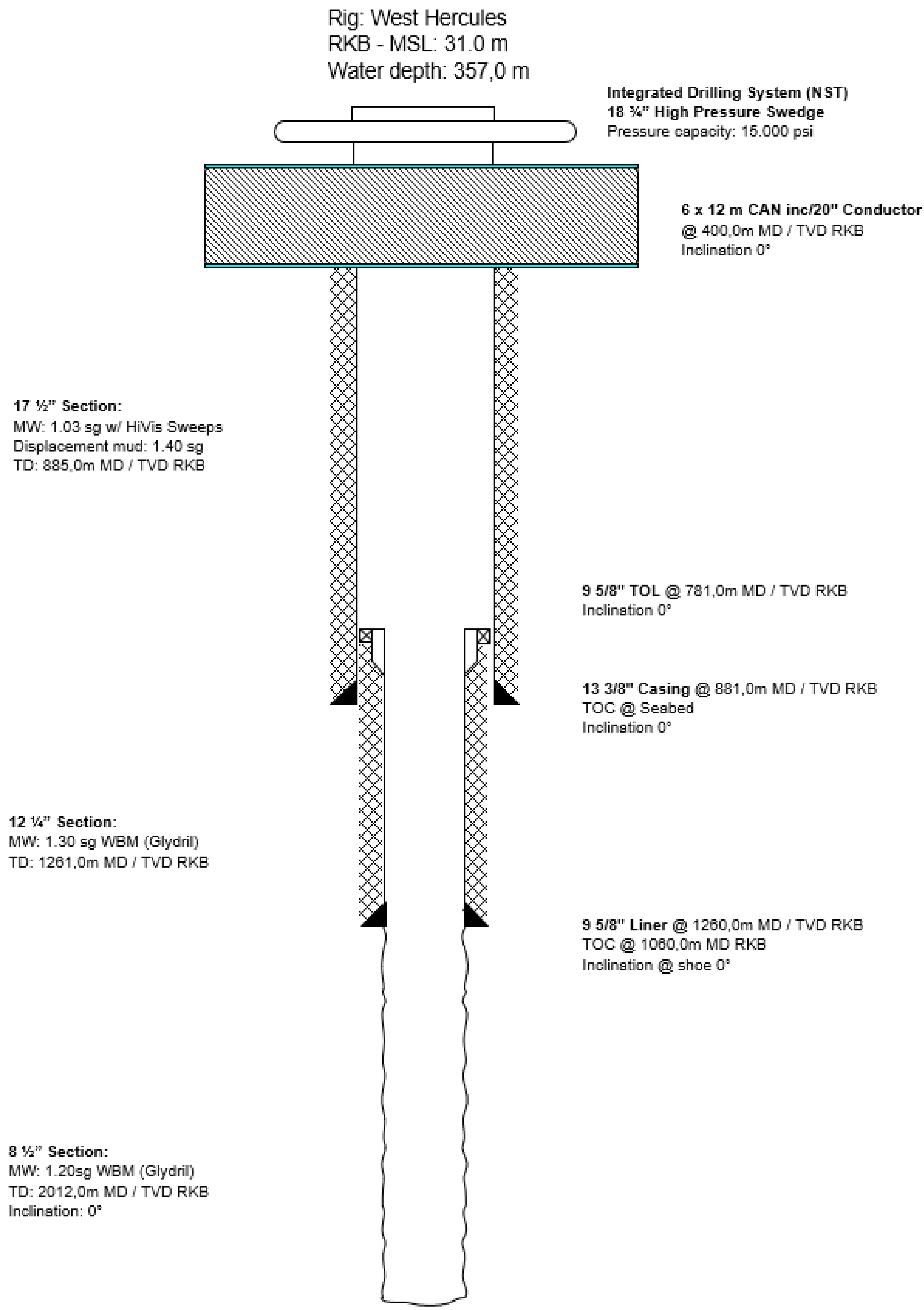

Figure 25: Casing design #5b - CAN-solution system (Integrated Drilling System WH). @Wintershall Dea

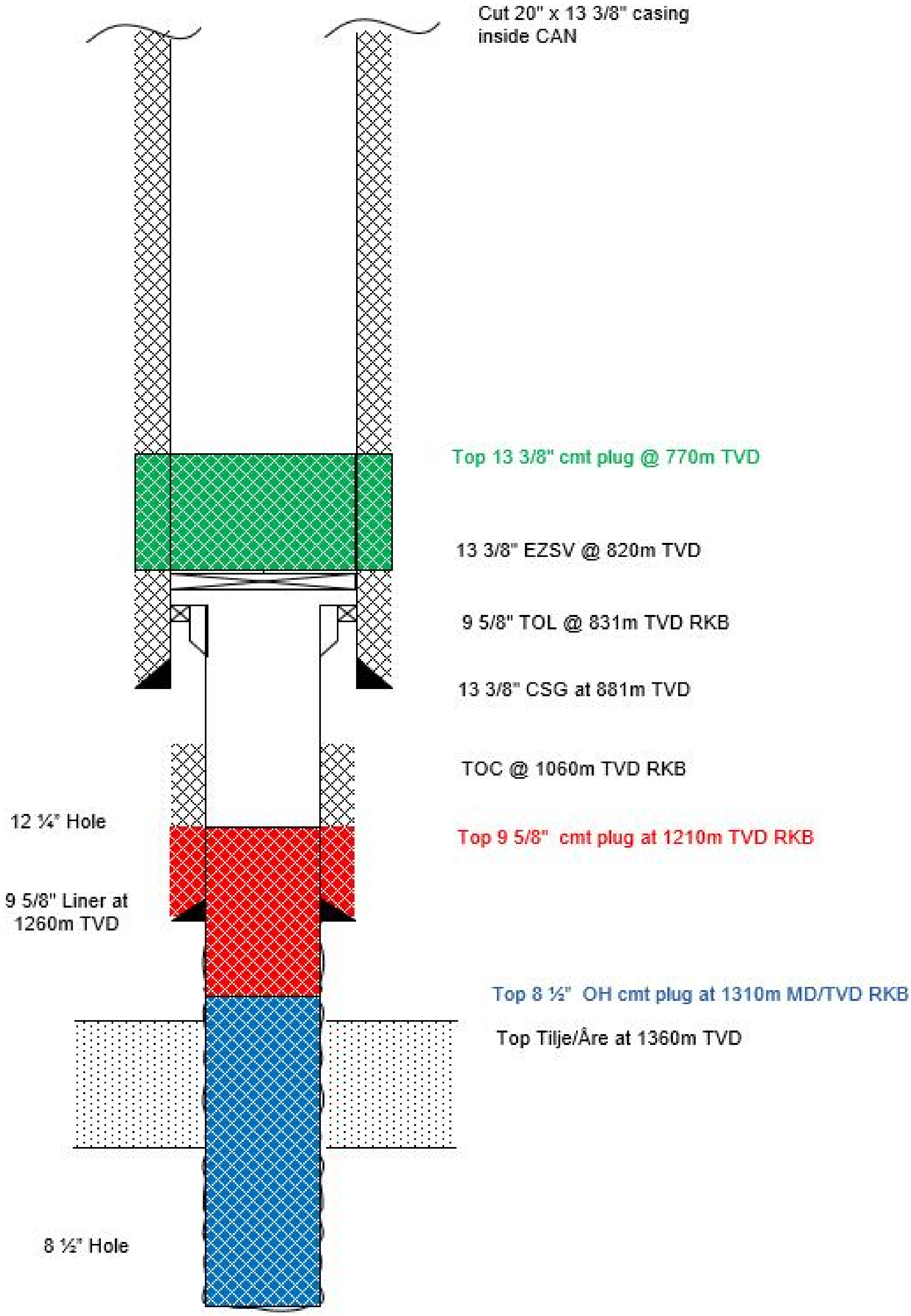

Figure 26: P&A program for Toutatis, dry case. @Wintershall Dea

APPENDIX II

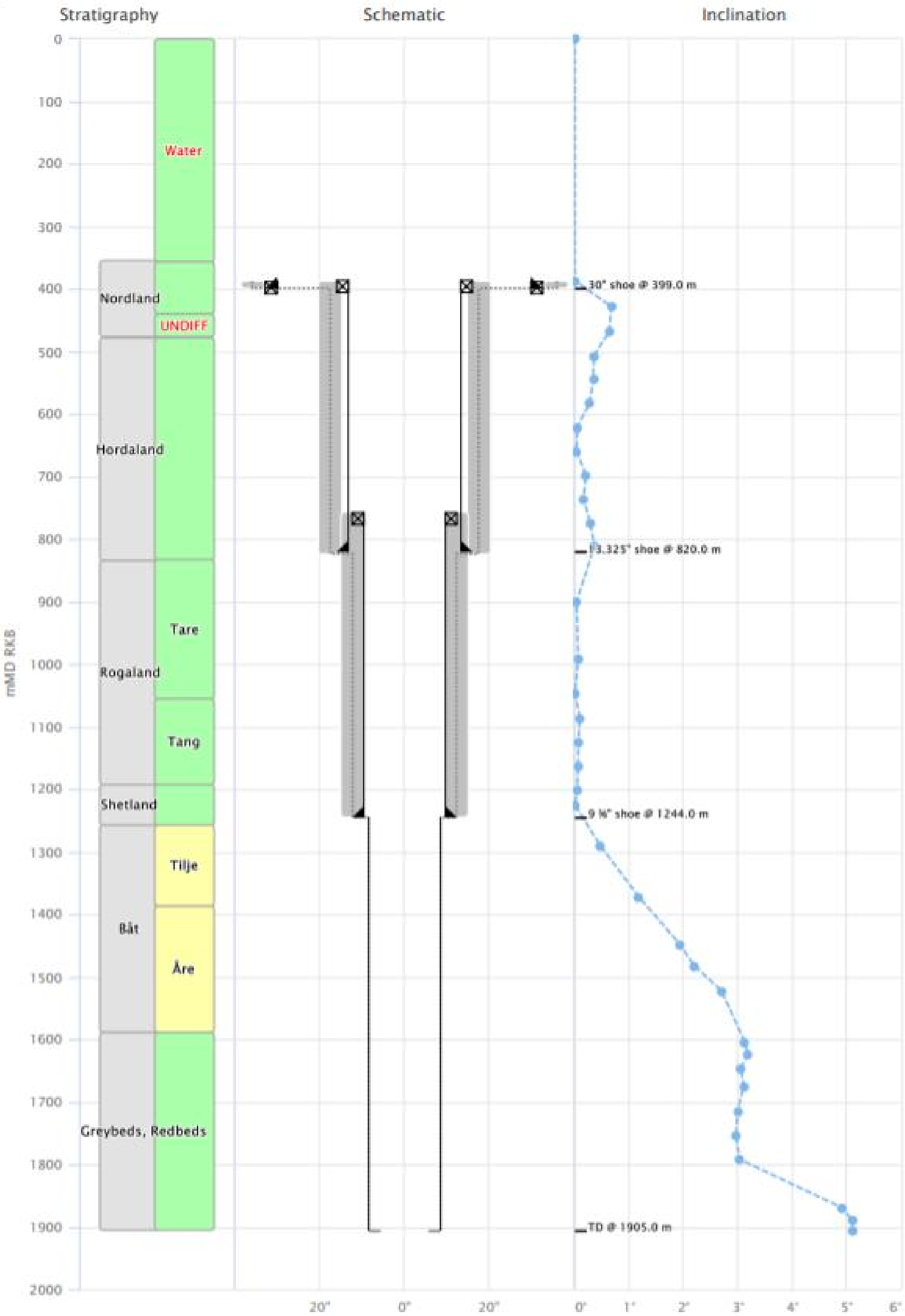

Figure 27: Final well design for Toutatis. @ iQx Software AGR, Wintershall Dea

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