Miodrag Ivanovic BSc

The Lightweight Drilling System Concept

Master's Thesis

Montanuniversität Leoben

Department Petroleum Engineering
Head: Univ.-Prof. Dipl-Ing. Dr.mont. Gerhard Thonhauser

Supervisor: Dr. Gerhard Thonhauser

Leoben, October 2016

Eidesstattliche Erklärung

Ich erkläre an Eides statt, dass ich die vorliegende Arbeit selbstständig verfasst, andere als die angegebenen Quellen und Hilfsmittel nicht benutzt und mich auch sonst keiner unerlaubten Hilfsmittel bedient habe.

Leoben, am ____________________ ____________________________________

Datum Unterschrift

Affidavit

I declare in lieu of oath, that i wrote this thesis and performed the associated research myself, using only literature cited in this volume.

Leoben, ______________ ______________________________

Date Signature

Abstract

Colour is the major difference in a picture of a rig floor taken in the fifties and one taken today!

What was concluded by Dominique Dupuis in a retrospective paper on slimhole technology (Dominique Dupuis, 2001) in 2001, still applies today. The oil and gas upstream industry lacks a game changing innovation to make it significantly more efficient. But with respect to the actual price scenario a game change is definitely needed.

This thesis presents the Light Weight Drilling System (LWDS) concept.
A technology that may provide a step-change in the upstream industry and enables significant performance improvement, allowing operators to explore and develop resources that cannot be drilled economically by conventional methods. Furthermore it offers a paradigm shift in formation evaluation techniques, giving the operator the opportunity to gather a more comprehensive view of the geology. The system builds on, and extends the widely researched basis of slimhole technology and claims to implement the lessons learned from the extensive campaigns in the eighties and nineties. It integrates various field proven technologies and makes use of an innovative bit system, called the Dual-Body Bit (DBB).

The thesis examines the system architecture and the sub-systems one-by-one. Furthermore a feasibility study, executed for a Central East European (CEE) operator, is presented to compare conventional drilling and LWDS performance. The study concludes with a 30% savings potential, although major parts of the LWDS were not considered, due to operator requirements. Additionally a systems thinking view on the LWDS concept is applied and risks and challenges for technology adoption are discussed. In the end the thesis states a cautious outlook on the technology development and deployment, concluding that a launch system implementation is feasible within one year.

Contents

List of Figures

List of Tables

1. Introduction

”Let’s drill in the garden of Versailles Palace!”

What reads as a joke, might have been the starting point for Messieurs Sagot and Dupuis in the early nineties when they started their slimhole campaign with French Elf Aquitaine, that resulted in the Foraslim system (A. Sagot and D. Dupuis, 1996). This campaign led to more than 30 slimhole wells around the globe before funding stopped and the technology stalled. One of these wells actually hit a target approximately 1,500 metres below the Palace of Versailles and was drilled from a surface site smaller than the Wibledon centre court, just at the palace garden’s fence. This well is outstanding, as no conventional drill rig was and still is not capable of accomplishing this task. And it was only one among several other slimhole campaigns worldwide during this time, of which Keith K. Millheim may have led the most pioneering one in the late eighties and early nineties with the AMOCO Production Company (Walker and Keith K. Millheim, 1990). The legacy of these campaigns prevailed only marginally, mainly in the small diameter downhole tools, applied in Coiled Tubing operations for example. In a retrospective paper from 2001 (Dominique Dupuis, 2001) Dupuis concludes ironically: ”What has changed between a picture *(comment by author: of a land rig)* shot in the 50’s and one in the 00’s: the color.” This statement sends a clear message, addressing the disappointing low impact the slimhole research efforts left in the end. The major reasons for this are discussed in more detail in Section 4, but anticipating it is stated that the major blocking factor was the transformation to the procurement-driven commercial model, the Western oil and gas upstream industry underwent in the late nineties. A technology like slimhole can only perform at its best and achieve ground breaking changes if it is deployed as an integrated system.

Now in 2016 the Light Weight Drilling System (LWDS) claims to become the true heir to the slimhole pioneers and continue where they stopped: commercialising the technology.

What makes this claim feasible are mainly two indicators. At first with a look at the (inflation adjusted) oil price development one will recognise a similar situation as in the late eighties (Figure A.1). After a steep price crash, the market indicators are directing towards a low to intermediate price scenario for several years up to a decade. The second indicator is fairly new. The numerous service companies of the nineties and early zeroes have merged to a few major service companies. Lately one of them, Schlumberger N.V. announced a strategy to become an increasingly integrated service provider. This leads to the assumption that integrated services will regain more acceptance and market share in the parts of the world where this commercial model lost importance.

This thesis describes the concept for a system that builds on, and extends the slimhole technology. The system architecture and subsystems are examined and a feasibility study, based on actual operator data is presented, comparing a conventionally drilled well against a well drilled with the LWDS. Furthermore a sensitivity analysis of the assumed parameters in the feasibility study is described and a Learning Curve Payout analysis is made on a hypothetical drilling campaign. Concluding a systems thinking view is applied on the LWDS and a cautious outlook is given. The final chapter summarises the thesis and indicates potential areas for further study.

As history and this feasibility study show, the LWDS is able to achieve 30% to 50% savings on total well cost; but only if it is deployed as an integrated system. With the previously mentioned two industry indicators the times are right to resurrect a promising technology and increase the upstream industries' efficiency substantially.

2. The Lightweight Drilling System Concept

When trying to reduce the total well construction cost by more than a third the major cost drivers have to be understood. Usually, for a conventional onshore well the major cost factors are

- the rig lease cost, strongly determined by the total well construction duration,
- the cost for commodities like casing, drilling fluid and wellhead
- the cost for subcontracted services,
- depending on the location the cost for well site preparation and access, and
- rig (de-)mobilisation.

In order to have a significant impact on all of these cost drivers, the complete well construction process needs to be reviewed and then optimisation needs to take place at the system level rather than within an isolated part of the technology only. Therefore the LWDS considers all of the following areas:

- well design,
- drilling process,
- downhole equipment,
- surface equipment (the "LWDS Rig"),
- logistics and well site,
- hydraulics and well control,
- formation evaluation.

Subsequently the major ideas within the previously defined areas are explained.

2.1. Well Design

The essence of the LWDS well design is derived from the slimhole drilling technology. Compared to conventional drilling smaller and lighter drill pipes are used to drill smaller holes. A key to the system is the narrow annulus, that drastically changes the hydraulic and mechanic characteristics of the well construction process. With these major changes in the wellbore geometry significant savings on the commodities are achieved and the utilisation of smaller surface equipment is enabled. The slimhole pioneers of the eighties and nineties have proven the concept of using slim and light mining drilling type pipes for drilling into sediment formations but never attempted to optimise these pipes. The LWDS tries to do so by looking at the drill string hydraulics first as they affect strongly the complete well construction process and show to be very different compared to conventional drilling.

2.1.1. Hydraulic Optimisation of LWDS Well Geometry

In order to optimise the hydraulic efficiency, the Hydraulic Power Losses (HPLs) inside the drill (and casing) string and in the annulus are investigated. The hydraulic power is defined as

$$P_{hyd} = p \times q \tag{2.1}$$

where

P_{hyd}	equals the hydraulic power,
p	equals the pressure, and
q	equals the flow rate.

The distribution of the Hydraulic Power Loss (HPL) across the wellbore is derived via multiplying the frictional pressure losses inside the drill string and in the annulus with the actual pumped flow rate. The frictional pressure losses are computed in good oil field practice according to the standard API RP 13D. Nevertheless, for the very narrow annuli and high drill string rotational speeds considered in the LWDS these calculations lead to insufficient results. This was already observed by the slimhole pioneers of AMOCO Production Co. in the eighties and they therefore introduced a hydraulics model, especially dedicated to slimhole wells with narrow annuli and high rotational speeds of the drill string described in Bode, Noffke, and Nickens, 1991.

It is assumed that, in order to optimise the hydraulic power loss across the wellbore the total pressure losses inside the drill string and in the annulus have to be equalised. In conventional drilling this is hardly achievable and the pressure losses inside the drill string contribute the great majority of the total pressure losses. Contrary to that in slimhole wells as they have been drilled back in the eighties and nineties of the last century this picture was just the opposite, with the major pressure losses in the annulus. Now for the LWDS the Flow Area Ratio (FAR) is introduced in order to investigate the optimum diameter relations for minimum Hydraulic Power Loss (HPL). The FAR is defined as

$$FAR = \frac{AA}{IPA} \tag{2.2}$$

where
AA equals the annular cross sectional area, and
IPA equals the inside pipe cross sectional area.

For a six inch hole the HPL for five scenarios is illustrated, assuming only the pressure losses occurring inside and outside the pipe body, assuming flush connections, and neglecting pressure losses at the Bottom Hole Assembly (BHA), bit and surface lines. A simulation length of 3,000 m is applied. Scenario 1 reflects a conventionally drilled hole of this size, being drilled with a 3 1/2 in drill pipe. Scenario 2 is based on the pipe selection used in the feasibility study described in Section 3 and Scenarios 3 to 5 illustrate custom pipe geometries in order to achieve certain FARs. For all scenarios the inside pipe pressure loss is modelled with the Bingham model. For Scenario 1 the annular pressure loss is modelled also with the Bingham formula, and for the other scenarios Nickens (Bode, Noffke, and Nickens, 1991) model is used. Tables A.1 and A.2 show the scenario parameters including the pipe geometries. As indicated in Table A.2 the flow rates were adjusted to have the same average flow velocity inside the annulus. Table 2.1 shows the parameters of the simulated mud and Figure 2.2 illustrates the simulation results. It indicates a clear reduction in total HPL of all LWDS scenarios (Scenarios 2 to 4), whereas Scenarios 3 and 4 show to be the optimum. Scenario 3 results in a total power loss of 28 kW, whereas Scenario 1 consumes 97 kW in this simulation. This translates to a saving of 71 %.

Concluding, this simulation leads to the assumption that an FAR between 0.5 and 1.0 leads to a minimised hydraulic power loss under the given circumstances.

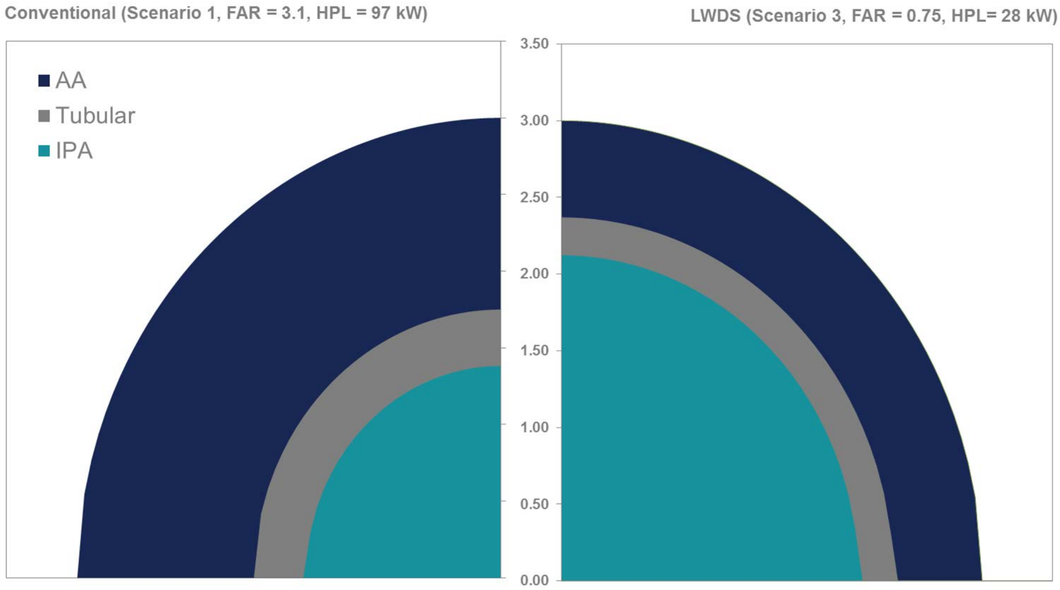

Figure 2.1.: Comparison of hole geometries for Scenarios 1 and 3.

Table 2.1.: Hydraulic optimisation. Mud parameters.

Mud Parameters		
Mud density	[ppg]	9.00
	[kg/m³]	1078
	[lbs/ft³]	173
Yield Point	[lb/100ft]	20
Viscosity	[cp]	31
600RPM read.		82
300RPM read.		51

Hydraulic Model Parameters	
Nickens (for low clearance annuli and high string RPM)	
n	0.6847
Rotation factor	2.0000
K	0.0071

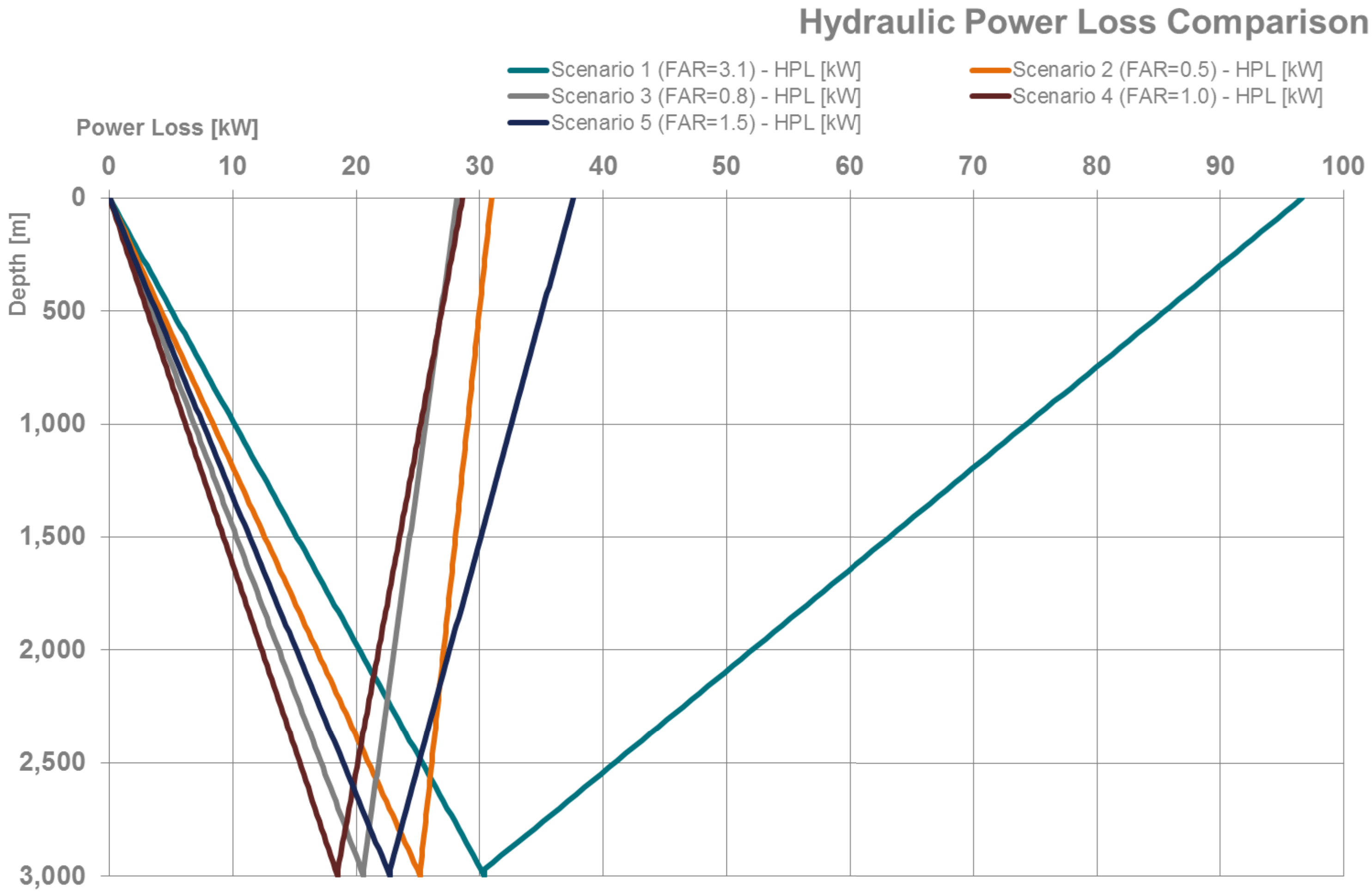

Figure 2.2.: Hydraulic Power Loss simulation results for five scenarios, indicating a significantly optimised system in case of scenarios 2 to 4, which are possible LWDS geometries, when compared to scenario 1, which represents a conventionally drilled hole of this size.

2.1.2. Proposed Hole and Pipe Diameter Combinations

With the optimum FAR range of 0.5 to 1.0 determined in the previous section, a proposal is given for a set of four hole and pipe diameter combinations for a hydraulically optimised wellbore construction, labelled with Alpha, Beta, Gamma and Delta. Table 2.2 shows the properties of the proposed system and Figure 2.3 illustrates the sizes in an onion plot and shows the corresponding hydraulic power losses, calculated on the same basis as in Section 2.1.1.

Table 2.2.: Proposed optimised hole and pipe size combinations with theoretical mechanical properties. Calculations are based on a steel with 80 ksi yield strength and 7,860 $\frac{\mathrm{kg}}{\mathrm{m}^3}$ density.

LWDS Proposed Diameters

No	Descr.	Hole Size [in]	Pipe OD [in]	Pipe ID [in]	Wall Thickness [mm]	Annular Clearance [in]	IPA [in²]	AA [in²]	FAR
1	Alpha	12.300	9.600	8.900	7.889	1.350	62.21	46.44	0.75
2	Beta	8.650	6.750	6.250	5.635	0.950	30.68	22.98	0.75
3	Gamma	6.000	4.740	4.250	5.522	0.630	14.19	10.63	0.75
4	Delta	4.200	3.600	3.000	6.762	0.300	7.07	3.68	0.52

LWDS Proposed Diameters - Theoretical Mechanical Properties of Tubulars (80 [ksi] Yield Strength)

No	Descr.	Weight [kg/m]	Tensile Strength [kN]	Burst Resistance [bar]
1	Alpha	40.6	2,851	352
2	Beta	20.4	1,431	358
3	Gamma	13.8	970	499
4	Delta	12.4	872	805

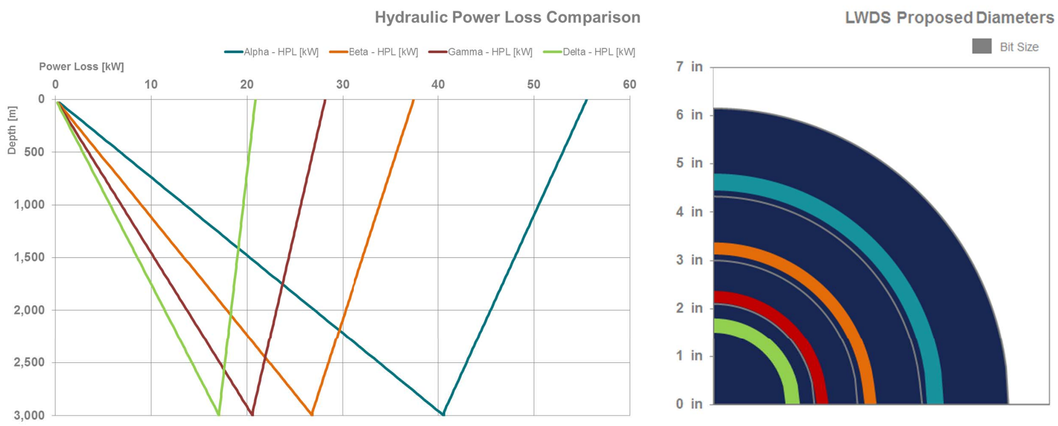

Figure 2.3.: Proposed hole and pipe size combinations for hydraulically optimised wellbore construction (right figure) and their corresponding HPL on a 3,000 m deep theoretical well (left figure).

2.2. Drilling Process

In order to reduce the time for drilling while at the same time improving wellbore quality and reducing risk for drilling problems a set of individually field proven technologies needs to be integrated and adopted for the LWDS. They comprise

- Slimhole Casing Drilling (SCD) technology,
- Wireline Retrievable BHA technology,
- Slimhole Continuous Coring (SCC) technology,
- accurate Delta Flow monitoring, and
- furthermore the LWDS utilises the Dual-Body Bit (DBB) technology, that did not penetrate the market yet, although laboratory test showed very promising results (Sousa et al., 1999).

Another major aspect of the LWDS drilling process are the very different operating parameters compared to conventional drilling. They are discussed at the end of the chapter.

2.2.1. Dual-Body Bit and Wireline BHA

During the nineties of the last century intensive research at the Montanuniversität Leoben was made to develop a bit system that mitigates the problems, the slimhole pioneers experienced back then with the mostly mining type impregnated diamond or drag type bits. Bencic et al., 1998 and Sousa et al., 1999 describe the design, manufacturing and testing of various Polycristalline Diamond Compact (PDC) and Tungsten Carbide Insert (TCI) type bits, consisting of an outer rim bit and an inner pilot bit. Figure 2.4 shows a set of these bits. They conducted large scale laboratory tests under high pressure conditions and proved the efficiency of the concept. The pilot bit can be tripped out by means of a wireline and enables to change it without the necessity for a round trip. The designers considered this the main advantage of their bit design and called it a "Dynamically Adjustable Tool". This feature compensates the low design freedom due to the reduced bit size and gives the drilling organisation a powerful tool to adjust the downhole drilling tool to the actual formation being drilled in a fraction of the time it would take with conventional drilling.

Furthermore the assumption is made that the stand-off pilot pit weakens the near wellbore area around and leaves a rock with a lower compressive strength to be destroyed by the rim bit. Additionally, due to the stand-off this mechanically pre-weakened area is infiltrated with mud and the increased pore pressure additionally reduces the effective compressive strength of the rock. At the moment of writing this thesis research work at the Montanuniversität Leoben is conducted to proof these assumptions by means of Mechanical Specific Energy (MSE) analysis.

Furthermore, the Wireline Retrievable BHA enables to switch from full hole drilling to coring in short time by pulling the pilot bit assembly on a wireline and replacing it with a core barrel. This concept is inherited from the slimhole pioneers, who in turn adopted the concept from the mining wireline coring technology. The LWDS attempts also to utilise the benefits of the mining type products but needs to modify the assemblies especially to withstand the higher mechanical static and dynamic loads, as well as the different hydraulics.

Moreover directional drilling tools, based either on Positive Displacement Motor (PDM) or Rotary Steerable System (RSS) technology can also be deployed with the Wireline Retreivable BHA system and eventually it enables also to run innovative drilling solutions. For example it is suggested to build an assembly, capable of utilising a mining type Downhole Hammer for drilling through hard formations efficiently.

Benefits

- Reduced MSE and thus more efficient drilling
- Enables to switch from full hole drilling to coring mode without the need for a round trip
- Enables to change the pilot bits according to the actual formation without the need for a round trip
- Enables Slimhole Continuous Coring (Section 2.2.3)

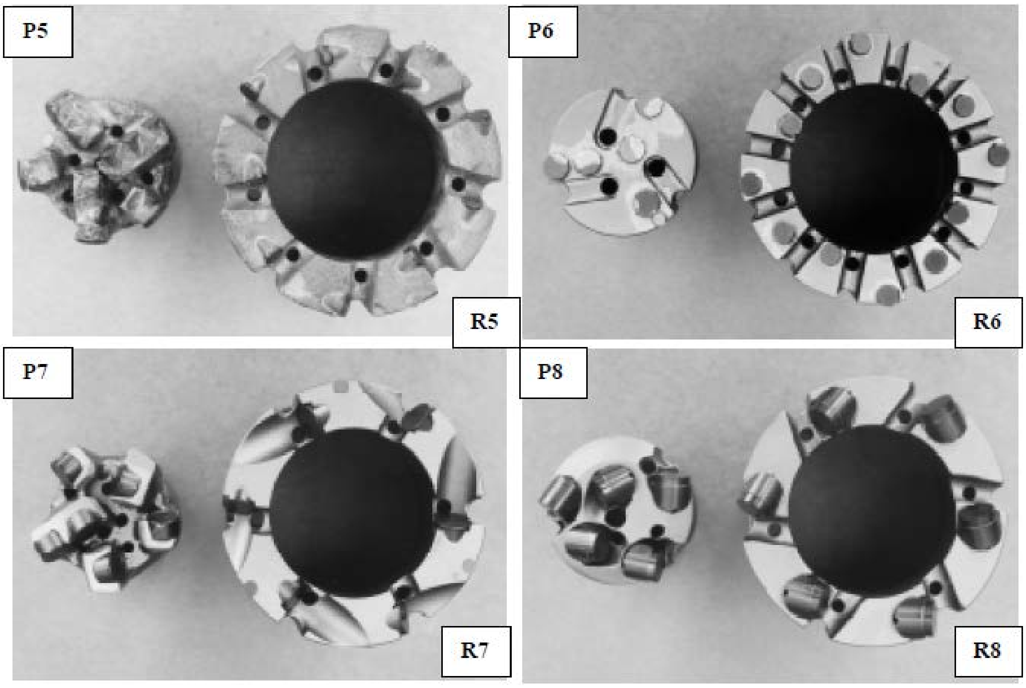

Fig. 3-Second Set of Testing Bits.

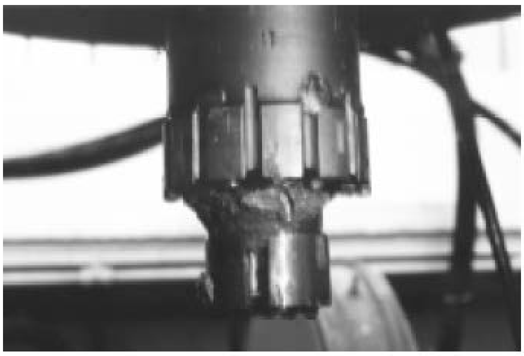

Fig. 4- Bit balling occurred at the corner between the drill plug and core bit (rim).

Figure 2.4.: Dual-Body Bit prototype bits designed, manufactured and tested by Bencic et al., 1998. Image from Sousa et al., 1999.

2.2.2. Slimhole Casing Drilling

By today Casing Drilling technology (also referred to as Casing While Drilling, CwD or Drilling With Casing, DwC, Liner Drilling or Drilling With Liner, DwL) is a widely accepted method especially for drilling top holes. Austrian operator OMV makes use of this technology on most of their Austrian and Romanian wells with great success (Sackmaier et al., 2014). Casing Drilling technology utilises the casing pipe as drill string and therefore eliminates the need for a drill string and dedicated bit and casing runs. Shepard, Reiley, and Warren, 2001 describe a success story where also production sections were drilled with this technology.

Within the LWDS it is a key technology for major time and logistics savings, wellbore quality improvement and drilling problems mitigation. The industry utilises Casing Drilling mostly for casing sizes above seven inch, whereas the LWDS anticipates most of the wellbore to be smaller in diameter. As Walker and Keith K. Millheim, 1990 define boreholes where 90 % or more of the total length is less then seven inch diameter as slim-hole wells, Casing Drilling used with the LWDS is referred to as Slimhole Casing Drilling (SCD).

Benefits

- Minimise open hole time and thus improve wellbore quality and mitigate drilling problem risk
- Save time for casing runs
- Improve wellbore integrity and risk for fluid losses due to the Plastering Effect (Karimi, Moellendick, and Holt, 2011)

2.2.3. Slimhole Continuous Coring

Walker and Keith K. Millheim, 1990 describe how AMOCO Production Co. utilised the wireline coring technique from the mining industry to drill in sediments. This is the underlying fundamental, the LWDS builds on. Same as the Slim-Hole High-Speed Advanced Drilling System (SHADS) the LWDS is able to core long intervals or even complete wellbores. This is mainly enabled by the previously discussed Wireline Retrievable BHA. Figure 2.5 compares the LWDS Wireline Retrievable BHA in full hole drilling mode and coring mode.

When coring with SCC a large amount of core might be generated. If the drilling organisation is to evaluate this core with conventional methods it would take excessive time and result in excessive cost. Thus again AMOCO introduced a field laboratory to assess the cores on-site in near real-time.

Spain, Morris, and Penn, 1992 describe the core laboratory and its field utilisation. The LWDS intends to incorporate a similar solution for wells with high exploratory character, where large amount of core is generated.

Furthermore, the SCC is not only for exploratory wells. Drillers may use this feature to improve also the drilling performance for any kind of well. An example would be to change to coring mode in very hard stingers where full hole drilling becomes very slow. Coring mode drilling reduces the amount of rock to be destroyed greatly and thus improves the Gross ROP significantly. Moreover in case of drilling problems a change to coring mode can give the drilling organisation the option to assess the root cause of the problems by means of a core and to adjust the counter actions according to the same. An example would be to choose instantly the right Lost Circulation Material (LCM) in case of losses.

Benefits

- Efficient coring of long intervals or even complete wells
- In combination with an on-site core laboratory efficient analysis of long core intervals enabled
- Enables to switch to coring mode for ROP optimisation (in hard stingers)
- Enables to take cores in case of drilling problems and adjust the counter actions

Figure 2.5.: Comparison of BHAs for full hole (right) and coring mode (left) of the LWDS. In full hole drilling mode the core barrel assembly is replaced by a drilling plug assembly that latches inside the SCD string. (1) latching and sealing assembly, (2) core barrel with bearing sections and core holder, (3) drilling BHA with optionally PDM, measurement tools and other tools, (4) rim bit only, for coring mode, (5) full hole mode with rim and pilot bit. Schematic illustration only. Not to scale.

2.2.4. Accurate Delta Flow Monitoring

Table 3.12 in Section 3.3.2.5 illustrates the need for an accurate monitoring of introduced and returned flow volumes. Due to the narrow annulus relatively small volumes of gas kicks (compared to conventional drilling) reduce the hydrostatic column significantly. A system for accurate Delta Flow monitoring is necessary in order to enable safe drilling practices. But moreover it enables the drilling organisation to facilitate also dynamic well control, described in more detail in Section 2.6. Additionally, such a system is also a subsystem of a Managed Pressure Drilling (MPD) system and the prerequisite for a fully closed loop drilling system.

A system to facilitate accurate Delta Flow monitoring in general consists of an inflow measurement either by a flow meter upstream the stand pipe or simply by utilising the already present stroke counters and calibrating the pump efficiency with the trip tanks. On the return side the standard flow paddle is not sufficient, nor the trip tank monitoring is. A flow meter in the return line is necessary, either of Coriolis-type, ultrasonic or electromagnetic types. Whereas Coriolis-type sensors are the most accurate and most expensive, ultrasonic and electromagnetic types proofed to be satisfactory with Bode, Noffke, and Nickens, 1991 and Dominique Dupuis et al., 1995. In addition to the sensors a set of choke valves and other piping elements is needed and a sophisticated software that models narrow annulus hydraulics accurately.

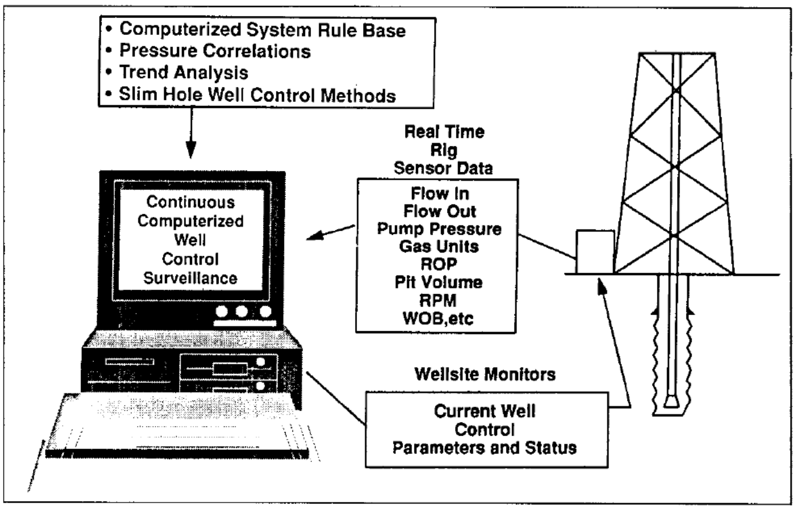

Figure 2.6.: Accurate Delta Flow Monitoring within the SHADS system from Bode, Noffke, and Nickens, 1991

2.2.5. Operating Parameters

The parameters a driller can influence are basically three: the speed of block movement, resulting in Weight on Bit (WOB), the number of pumps active and strokes per minute on each pump, resulting in a certain flow rate and the rotational speed of the top drive or rotary table. All of these three parameters are very different in slimhole drilling and thus also with the LWDS. The flow rate and the WOB are significantly lower, whereas the rotational speed is significantly higher. Table 2.3 compares values for conventional, slimhole and LWDS technologies.

Table 2.3.: Comparison of operational parameters for conventional land drilling, LWDS and slimhole technologies. (1) proposed values, (2) estimated value.

Drilling Parameters Comparison			
Parameter	Conventional	LWDS	Slimhole
Flow Rate	up to 3,500 l/min	up to 1,000 l/min	up to 600 l/min
Weight on Bit	up to 20 t	up to 3 t (1)	up to 1.5 t (2)
Rotational Speed	up to 180 RPM	up to 450 RPM (1)	up to 1,700 RPM

2.3. Downhole Equipment

Some of the essential parts of the LWDS downhole equipment are discussed in the previous sections and illustrated schematically in Section 2.5. Figure 2.7 illustrates the system architecture of the LWDS downhole equipment. The major technologies are

- Pipes
- Drilling Bits (Dual-Body Bit (DBB))
- Wireline BHA
- Cementing Equipment

Figure 2.7 illustrates that a major development effort to launch a LWDS lies within the downhole equipment. In general, the downhole technologies needed are already existing and field proven but need to be adapted to the reduced diameter and/or oil and gas well drilling environment.

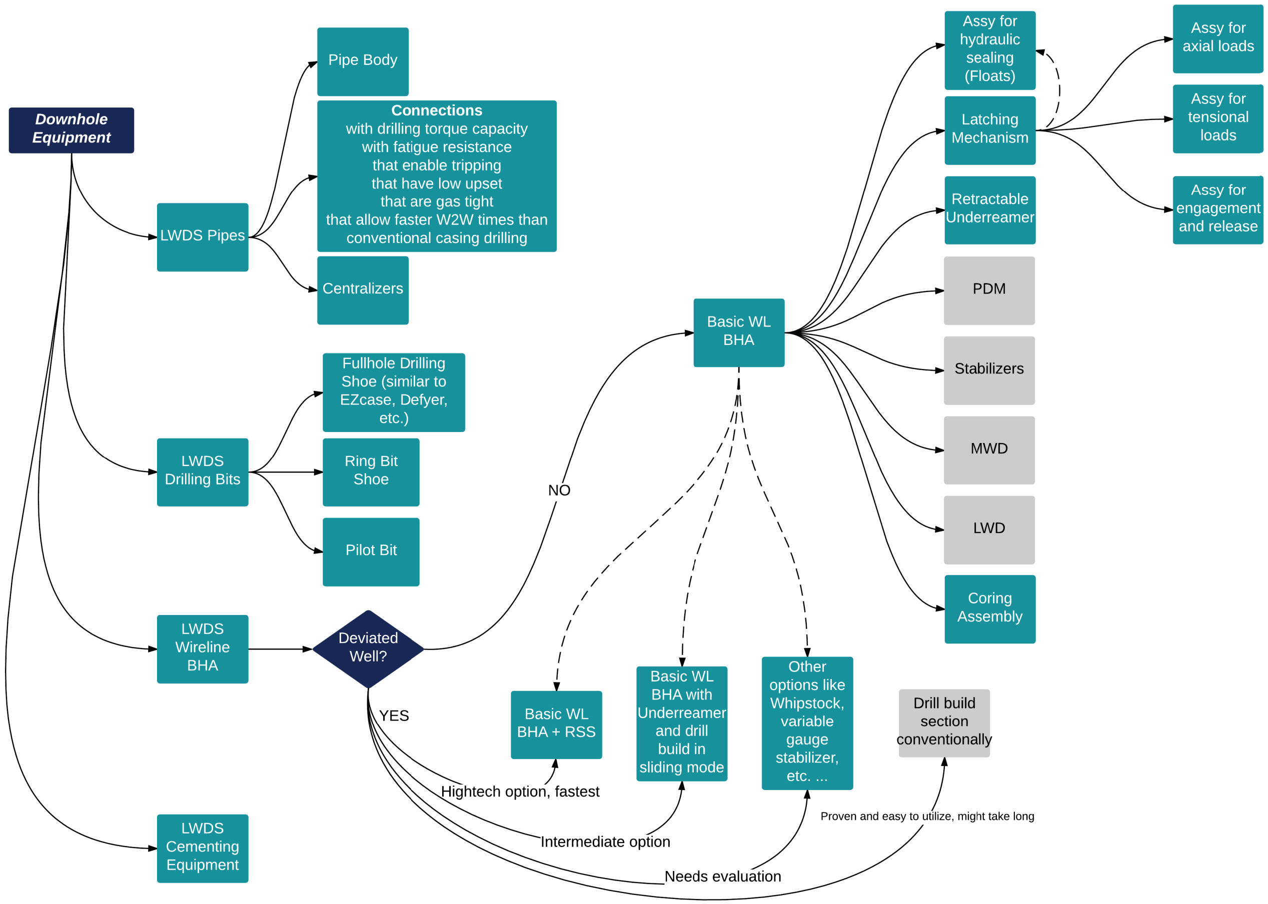

Figure 2.7.: Overview of LWDS downhole system architecture. Green items indicate areas, where research and innovation is needed. Grey areas indicate readily available technology that can be utilised for the LWDS.

2.3.1. Pipes

The LWDS pipe bodies shall be designed and developed based on the hydraulic optimisation discussed in Section 2.1.1. For the LWDS pipe connections modified casing connections shall be developed. DeLange, Evans, and Griffin, 2002 in their patent for casing drilling connectors state the main objectives for such are to increase fatigue resistance and enhance torque capacity compared to conventional casing connector designs. This also holds true for the LWDS pipe connectors. Additional requirements are a low external upset, tripping capability, gas tightness and a fast connection procedure.

2.3.2. Drilling Bits

The LWDS utilises the DBB technology designed and tested by Bencic et al., 1998 discussed in Section 2.2.1.

2.3.3. Wireline BHA

The LWDS Wireline Retrievable BHA is introduced in Section 2.2.3. It is a critical sub-technology within the LWDS and enables drilling in full hole mode, coring mode and eventually shall allow the LWDS to drill also directional holes. Furthermore it may be utilised to introduce new innovative drilling technologies instead of the pilot bit, for example hydraulic Down The Hole (DTH) hammers. Within the Wireline BHA technology the most critical assemblies are the Latching Mechanism and the Sealing Assembly. These assemblies were also identified by Bencic et al., 1998 as crucial and a significant effort was spent to adopt the mining type design to an oil field design. Especially torque and axial loads are increased when drilling sedimentary formations. The Latching and Sealing Assemblies will consist of pipe pieces with certain geometries ("Latching Collar" or "Profile Nipple"), placed near the bottom of the LWDS pipe string and counterparts within the Wireline Retrievable BHA.

2.3.4. Cementing Equipment

In order to be able to cement the casing in place, pump-able cementing floats need to be developed. They may utilise the same Latching Collar or have dedicated geometries. A solution to this is presented for example by Vert and Angman, 2008 of Tesco Corporation. Figure 2.8 shows this option, utilising an expandable, pump-able Latching Collar, to which in a second circulation the Float Collar engages.

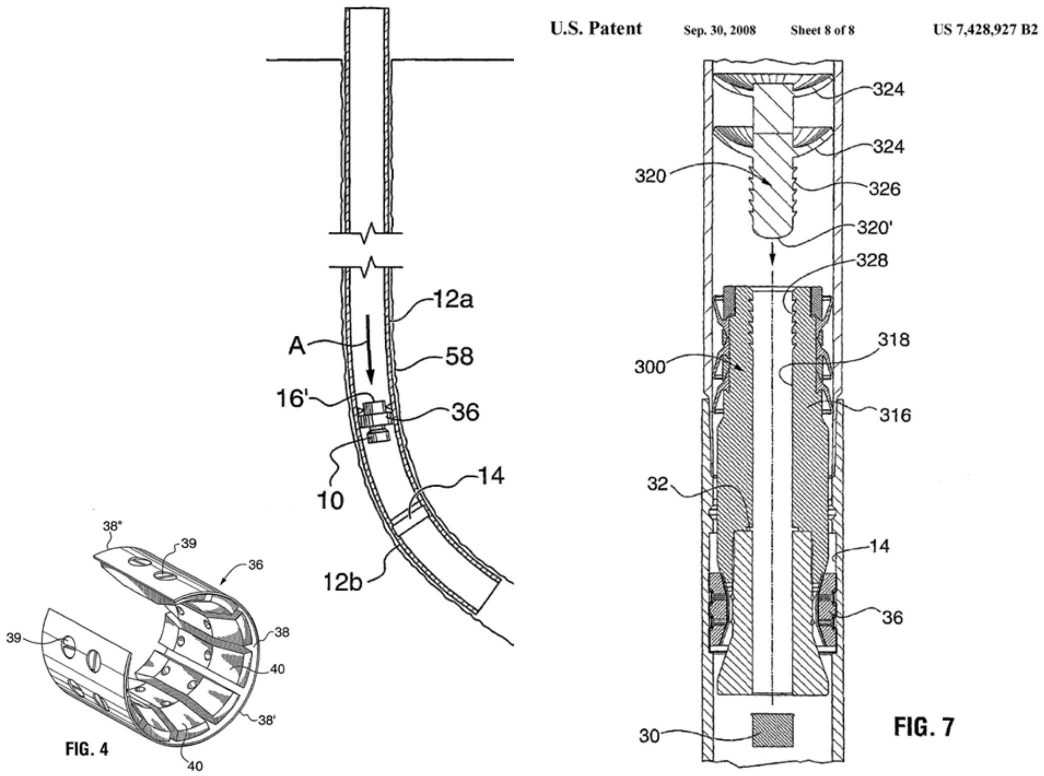

Figure 2.8.: Pump-able cementing float collar system patented by Vert and Angman, 2008, as developed for Casing Drilling. An expandable latching ring (l) is pumped down the casing (m). Later the float collar is pumped and latched into the latching ring and cement can be displaced conventionally with displacement plugs (r).

2.4. Surface Equipment

Figure 2.10 illustrates the system architecture for the LWDS surface equipment, indicating that the majority of surface equipment technologies is readily available. The surface equipment needs to enable the operating parameters discussed in Section 2.2.5 while in the same time being generally smaller and more efficient with a reduced footprint in terms of environmental, economic and energy aspects. A major factor for choosing the right surface equipment is whether a small (in the 60 to 250 ton hookload capacity range) rig has to be upgraded or a completely new built rig is considered. Obviously, the full savings and improvement potential can only be achieved with a completely purpose built LWDS rig. Andre Sagot and Dominique Dupuis, 1994 describe a "fit-for-purpose built rig" with less than 850 m^2 footprint, allowing it basically to be rigged up on the centre court of Wimbledon (spans 41 m $\times$ 22 m). This design allowed the company Elf Aquitaine (today's Total S.A.) to drill below the garden of the Palace of Versailles as described in A. Sagot and D. Dupuis, 1996, what was and still is impossible with conventional drill rigs. A three dimensional drawing of their rig layout is given in Figure 2.11. Nowadays, a LWDS rig would have the same basic requirements like the Foraslim rig described in Andre Sagot and Dominique Dupuis, 1994.

Figure 2.9 compares a potential LWDS rig, capable of drilling 10,000 ft (labelled LWDS 10K) and a conventional rig used onshore Europe or US to drill a similar well. Only a few specifications are selected, but at a glance the major savings in energy consumption and footprint area are evident. Only the rotational speed capacity of the top drive system needs to be significantly higher than with conventional drilling. With the hook load capacity of 60t a LWDS Delta string (see Section 2.2) of 4,800 m length theoretically could be handled and a Gamma string of 4,300 m.

Surface Handling Procedures

Surface handling procedures have to be considered carefully in the design of the surface equipment (LWDS Rig). Especially wireline BHA and core handling needs to be safe and efficient in the same time. Here lies the major drawback with conventional rigs upgraded with the LWDS Upgrade Package (Figure 2.10).

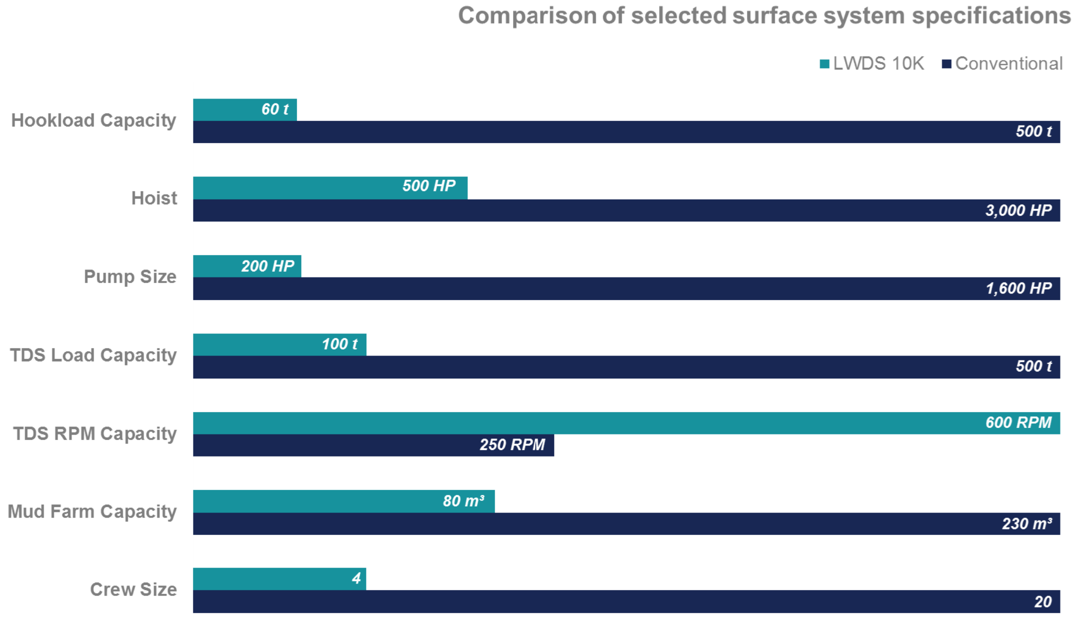

Figure 2.9.: Comparison of basic surface system specifications for LWDS and conventional drilling. All specifications are significantly lower except rotational speed capacity of the top drive system.

Automation

In times of Big Data, Internet of Things (IoT) and Industry 4.0 there is a great temptation to design a fully automated rig and in developed regions like North America and Europe this is a reasonable approach, further reducing total cost, especially when shale drilling is considered. Nevertheless, as a main application of the LWDS are drilling campaigns in remote areas, a delicate balance needs to be found between automation and mechanisation. Thomas B. Sheridan and Verplank, 1978 give a comprehensive classification of the automation level and Parasuraman, T. B. Sheridan, and Wickens, 2000 depict a systematic approach on how to choose the right level of automation. Macpherson et al., 2013 in their paper related to automation within the drilling industry refer to Endsley and Kaber, 1999, where also a ten level classification based on Thomas B. Sheridan and Verplank, 1978 is made.

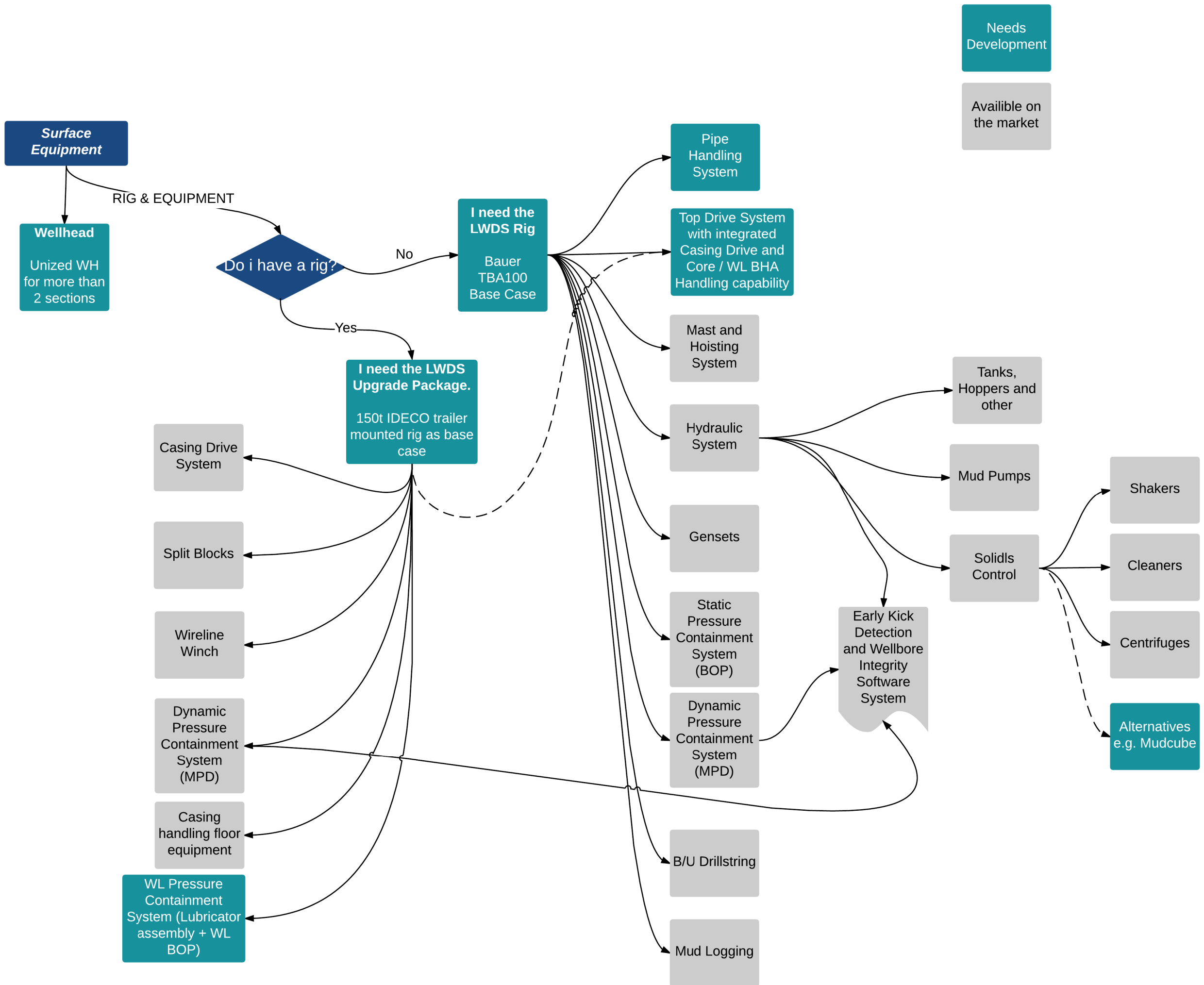

Figure 2.10.: Overview of LWDS surface system architecture. Green items indicate areas, where research and innovation is needed. Grey areas indicate readily available technology that can be utilised for the LWDS.

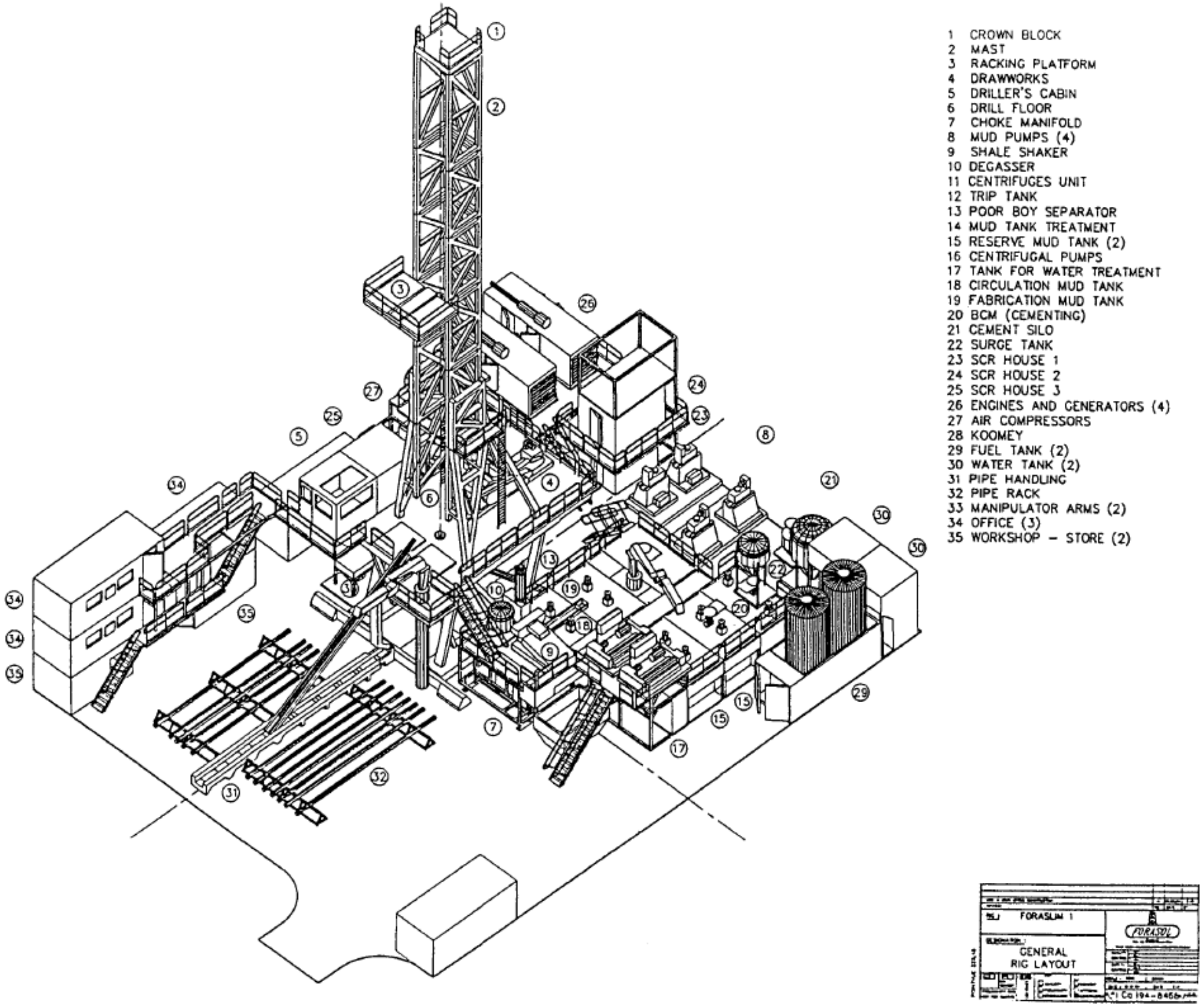

Figure 2.11.: 3D view of Foraslim rig (Andre Sagot and Dominique Dupuis, 1994). The site area spans at approximately 32 m × 26 m. In comparison the tennis centre court in Wimbledon spans 41 m × 22 m.

2.5. Logistics and Well Site

This section shows the impact of the down-sized surface equipment on logistics effort and well site requirement. Figure 2.12 illustrates the total site requirement of LWDS rigs and conventional rigs and the associated number of flights needed to move the rig base unit per helicopter. Furthermore, the LWDS enables major reductions in bulk load and associated transport cost, shown in Figure 2.13.

A. Sagot and D. Dupuis, 1996 explain another major cost savings factor when it comes to logistics. Not only the number of loads are reduced and the transport via helicopter is enabled, but moreover the mobilisation of the complete rig is greatly eased. Their Foraslim rig (Andre Sagot and Dominique Dupuis, 1994) could be ocean transported as a conventional container ship load and mobilised from port to site with barges and trucks. Groenevelt et al., 1997 describe how this approach enabled Shell and Forasol to mobilise the rig from Ghana to Romania in six weeks. Shanks and Williams, 1993 describe how they mobilised their slimhole rig from Texas to Chile also via ocean freight and further to Bolivia with a Hercules C130 air plane.

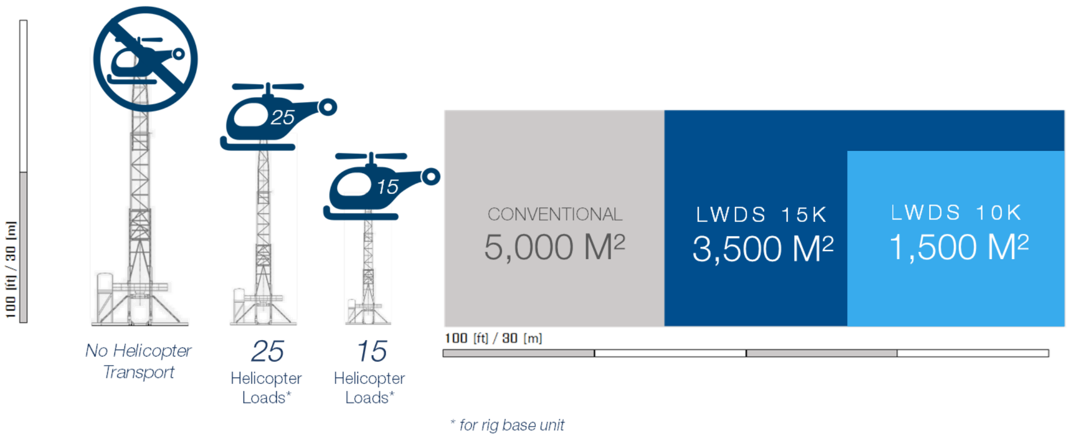

Figure 2.12.: Comparison of well site and transport requirements for conventional and LWDS rig. The numbers of helicopter transports are based on 3.5 t maximum load per transport.

2.6. Hydraulics and Well Control

LWDS hydraulics are very similar to slimhole hydraulics with the main characteristic of much higher annular pressure losses compared to conventional drilling. Major work on this is described by Bode, Noffke, and Nickens, 1991, who also established analytical solutions that can be used by field engineers.

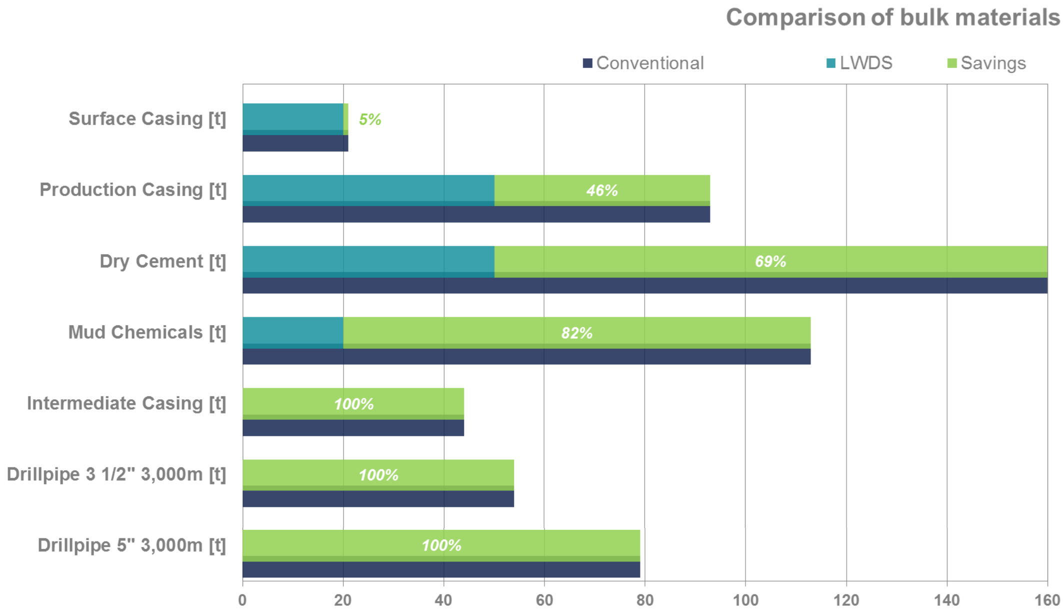

Figure 2.13.: Comparison of logistics for a conventionally drilled and a LWDS well. These savings are enabled by the LWDS well design and they can be directly related to associated cost for transportation. Savings are based on feasibility study results, presented in Section 3.

Cartalos and Dominique Dupuis, 1993 continued this work and added the effect of eccentricity. More recent researchers in this area, for example Ofei et al., 2015, make use of Finite Element Method (FEM) simulations to predict accurately the flow behaviour and resulting pressure losses within narrow annuli.

What most of the early slimhole hydraulics researchers had in common was, that they used test wells, containing parasitic casing strings, equipped with pressure sensors and injection lines in order to build their hydraulic models on one hand, but moreover, to design safe well control systems and procedures on the other. Figure 2.14 shows a cross-section of SHEDS No. 7; AMOCO's well-control research well in the nineties. Mobil Oil Co. drilled prior to a slimhole campaign in Bolivia a test well in their Dallas Research Lab called Farmers Branch No. 1 and equipped it similarly (Shanks and Williams, 1993).

Dynamic Well Control

Dynamic Well Control is a unique feature, usually available with slimhole rigs and operations only and shall be an integral part of the LWDS. The accurate Delta Flow monitoring on a LWDS rig allows to detect small influx volumes from the wellbore. Countermeasures can be classic ones, like mud weight increase or dynamic kill, which is simply the increase in pump flow rate or the increase in pipe rotational speed. Both have the same effect of increasing pressure losses inside the annulus and thus killing the well. In combination with an automated system this form of well control is able to respond faster than any human being resulting in increased safety on site.

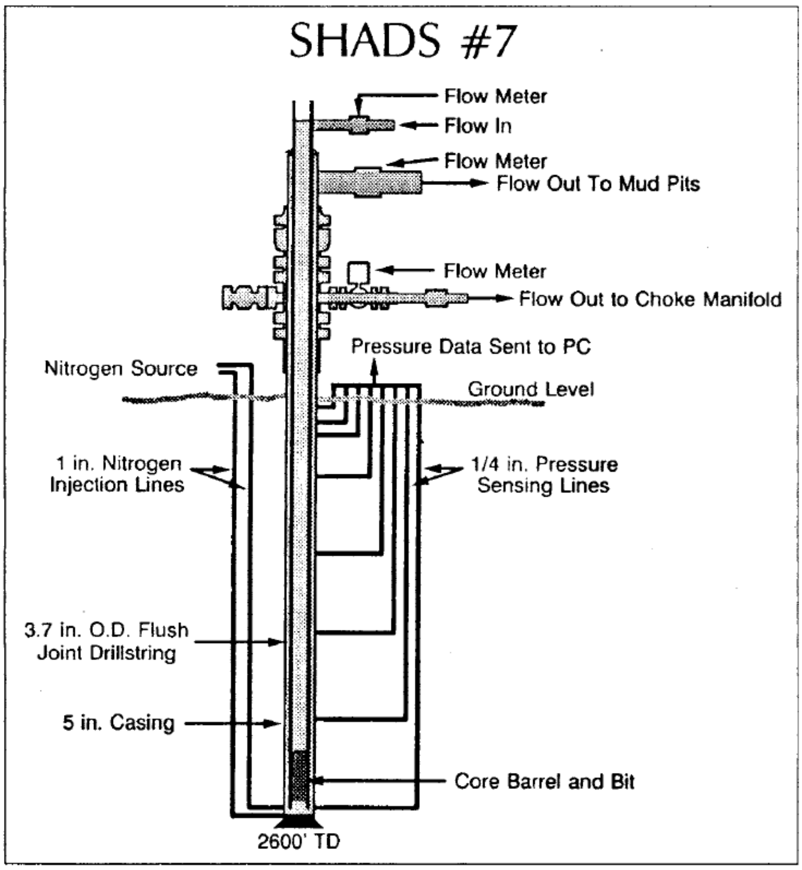

Figure 2.14.: AMOCO Production Co. SHADS No. 7 well-control research well (Bode, Noffke, and Nickens, 1991).

2.7. Formation Evaluation

In order to make continuous coring a viable alternative to conventional formation evaluation a different concept of core evaluation than the currently available needs to be applied. The current model for core evaluation is based on relatively short core lengths (compared to the total wellbore length) that are preserved and shipped to one of the few core laboratories around the globe. Also coring is a separately contracted (and invoiced) service with additional personnel and equipment and a major cost driver. Now, as the LWDS incorporates the continuous coring ability (Section 2.2.3) in its integrated approach, no separate service is needed for the process of taking cores. As a next logical step the core evaluation is also given thought and again the history delivers a role model. Spain, Morris, and Penn, 1992 describe a mobile core laboratory that is to be deployed in the field. The data gained from the laboratory, combined with classic mud logging and expert analysis result in a near real-time log that significantly enhances the decision management on site (Figure 2.16). Figure 2.15 shows a schematic plan view of the SHADS on-site core laboratory. The LWDS intends to deploy a similar laboratory for wild cat, exploration and scientific wells.

Furthermore, a model is considered where a similar laboratory is deployed in an area with high drilling activity, serving as a laboratory for several LWDS rigs and digesting their cores. Additionally, conventional rigs can feed the laboratory with their core sections. This field laboratory may not be considered as a direct competition to classic stationary rock laboratories, which many major oil companies (national and international) have already in place, but as a complement to support fast decision making. The on-site mobile laboratory is able to deliver the majority of information necessary for decisions related to the actual drilling and completion procedure and to select the zones of interest to be sent to the stationary laboratory in order to obtain more sophisticated data. With this model the LWDS mobile core laboratory shall be economically feasible and make up for the comparably low number of exploration wells drilled. Furthermore, this approach allows to shift from the conventional wireline logging approach to a core based formation evaluation approach with supplementary cased hole logs.

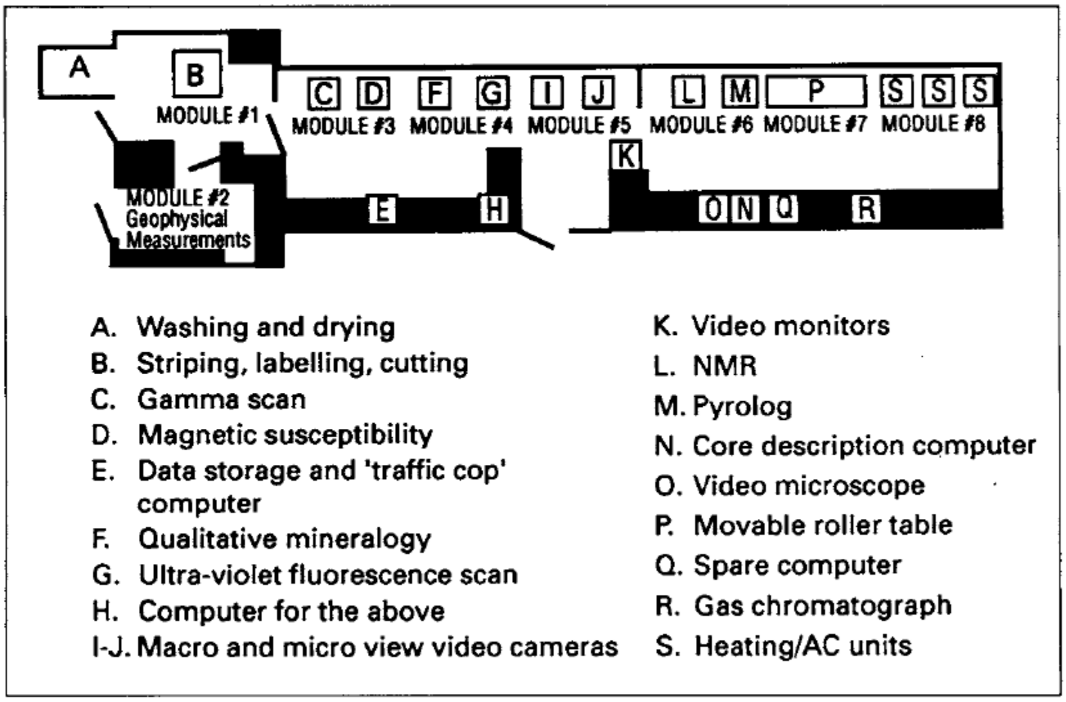

Figure 2.15.: Schematic of AMOCO Production Co. SHADS on-site core evaluation laboratory (Spain, Morris, and Penn, 1992).

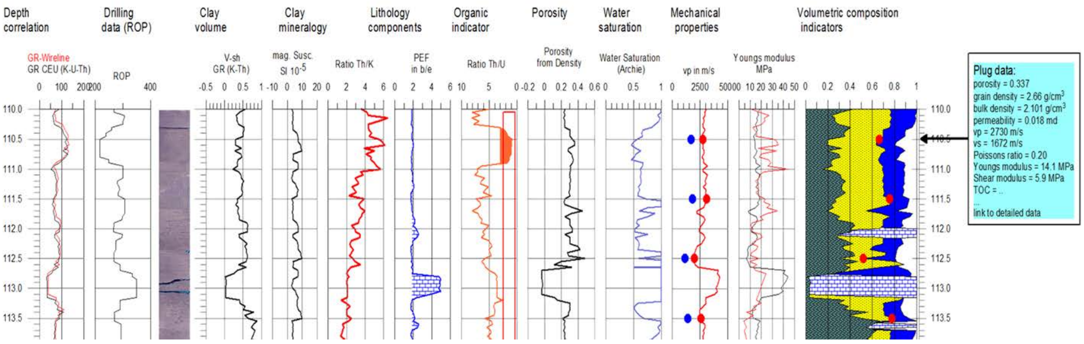

Figure 2.16.: Sample near real-time composite log (image courtesy of TDE Group GmbH).

3. Feasibility Study

This feasibility study was developed to identify the time and cost savings potential for a CEE operator when utilising the LWDS concept for a planned exploration well (ZA11) in the western Pannonian Basin. The operator provided geological data, well requirements, offset well data and the reference well design and plan to compare with. With the operator's well design and plan the project is economically not feasible.

The operator's requirements included a 160 t hookload capacity mobile rig to be applied and a defined surface location. Thus major savings by utilisation of the LWDS rig could not be assessed. Furthermore, the required rig upgrades for capability of drilling with the LWDS downhole components were assumed to be contracted services, having a major impact on the total cost. Additionally, a major operator requirement was the capability to run a completion into the well and use it as a producer if the well proofs to be economically viable.

Result

For the subsequently presented well design the LWDS is able to save 62 % of the drilling time, which corresponds to 54 % of total well construction time savings including completion and a well test. When comparing the total well cost a savings potential of 30 % is identified on this single well. Furthermore, a sensitivity analysis was carried out, showing that the drilling time is the most sensitive variable in the model. If drilling time exceeds +110 % of the estimated, the savings on total well cost vanish. The study is based on a single well, where sophisticated technology is acquired from third parties via service contracts. This is to enable a short lead time and early realisation of the project. If a multi-well campaign is considered the acquisition and operation of high CAPEX equipment, as well as the optimisation and design of proper LWDS pipes could open up additional savings potential.

3.1. Geological Summary

The target formation is situated on the north eastern slope of a Paleogene canyon fill, called Nesvačilka Paleovalley (Golonka and Picha, 2006), which is the result of the sedimentation of an erosional palleovalley below the Karpathian Neogene Foredeep. The valley is situated above a Jurrasic rift structure, called the Nesvačilka Graben (Golonka and Picha, 2006). Figure 3.1 shows a plan view and a cross section of the Paleogene system and Figure 3.2 shows a schematic of the Nesvačilka geology with an actual 3D seismic correlated. The target body, which top is prognosed at 2,345 m True Vertical Depth (TVD) is a submarine sandstone and conglomerate channel and expected to be the southward continuation of a proven field, which is suspected to be sealed off due to tectonic events. The petroleum system's trap is of stratigraphic type where the target horizon is pinching out on the erosional surface of Culmian wackes and shales. Vertical sealing is provided by Pelitic layers, building the most of Paleogene in this area. As a source rock the Mikulov marls are suspected, which provided also the hydrocarbons for surrounding oil fields Uhřice and Žarošice . Table 3.1 gives a general summary of the main geological information and Table 3.2 gives an overview of the lithological sequence for the well.

One offset well was drilled into the expected center of the target body labelled Uhřice 10 (UH10) in 1980 with log and core data in moderate quality available. Figure 3.3 shows an interpreted composite log with the target Basal Paleogene Clastics (BPC) at 2,150 m TVD for which the core section is also shown adjacent. Well tests were executed and water with dissolved gas was produced. Well ZA11 is supposed to penetrate the BPC layer at an elevated depth and have an increased production. Further images and informations on the geology are given in Appendix B.

The pressure regimes throughout the sequence are expected to be hydrostatic, with a low risk of over-pressured shallow gas horizons between 150 mTVD and 300 mTVD. The temperature gradient is estimated with 2.5 °C/100m to be uniform along the complete profile.

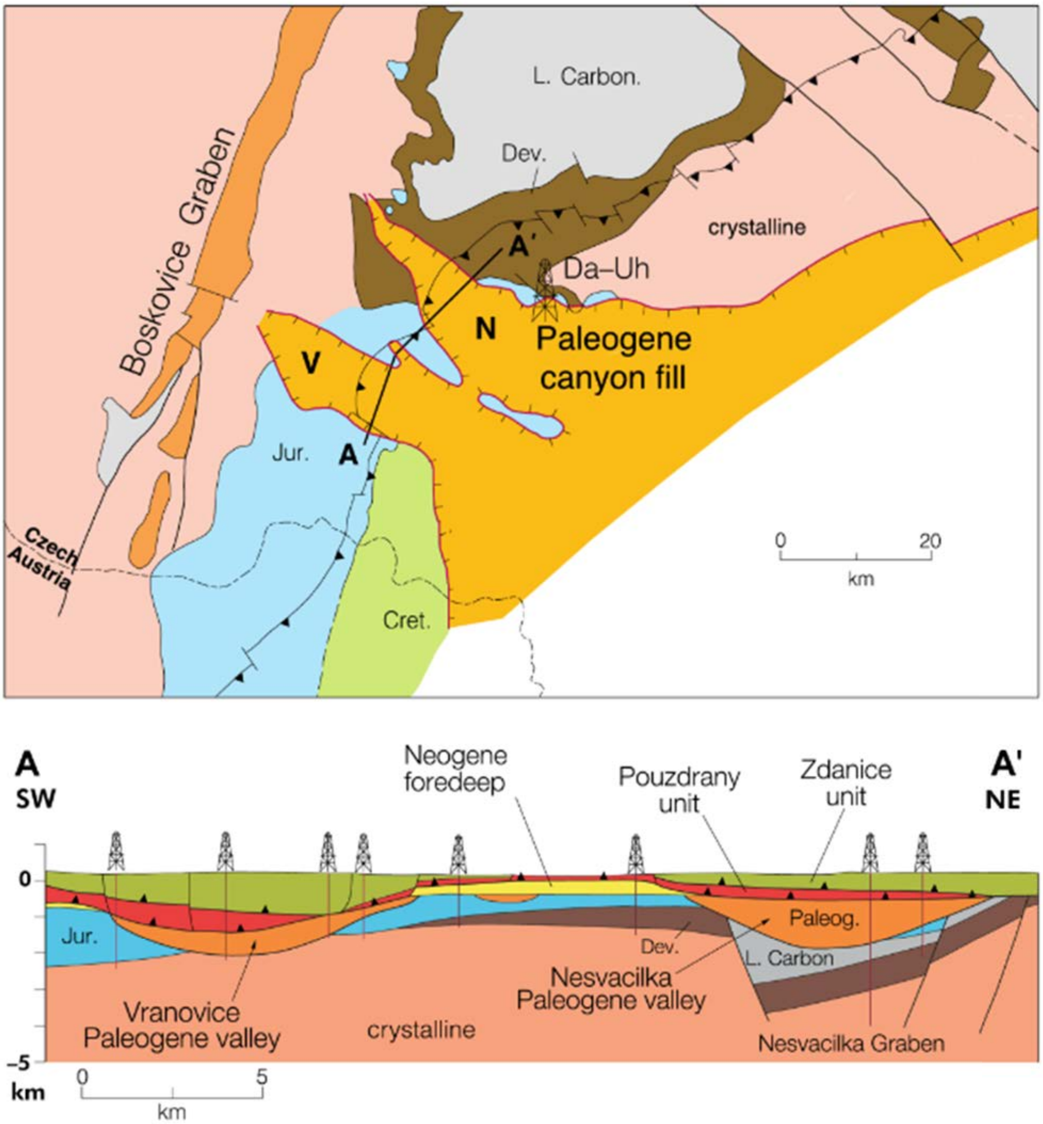

Figure 3.1.: Figures from Golonka and Picha, 2006 showing a subcrop map of the Pre-Neogene Nesvačilka (N) and Vranovice (V) paleovalleys. Da-Uh indicates the location of Dambořice and Uhřice oil and gas fields where adjacent the target BPC formation is situated. The cross section AA' shows the main bodies of the geological system, with the erosional paleovalleys cut into the older strata.

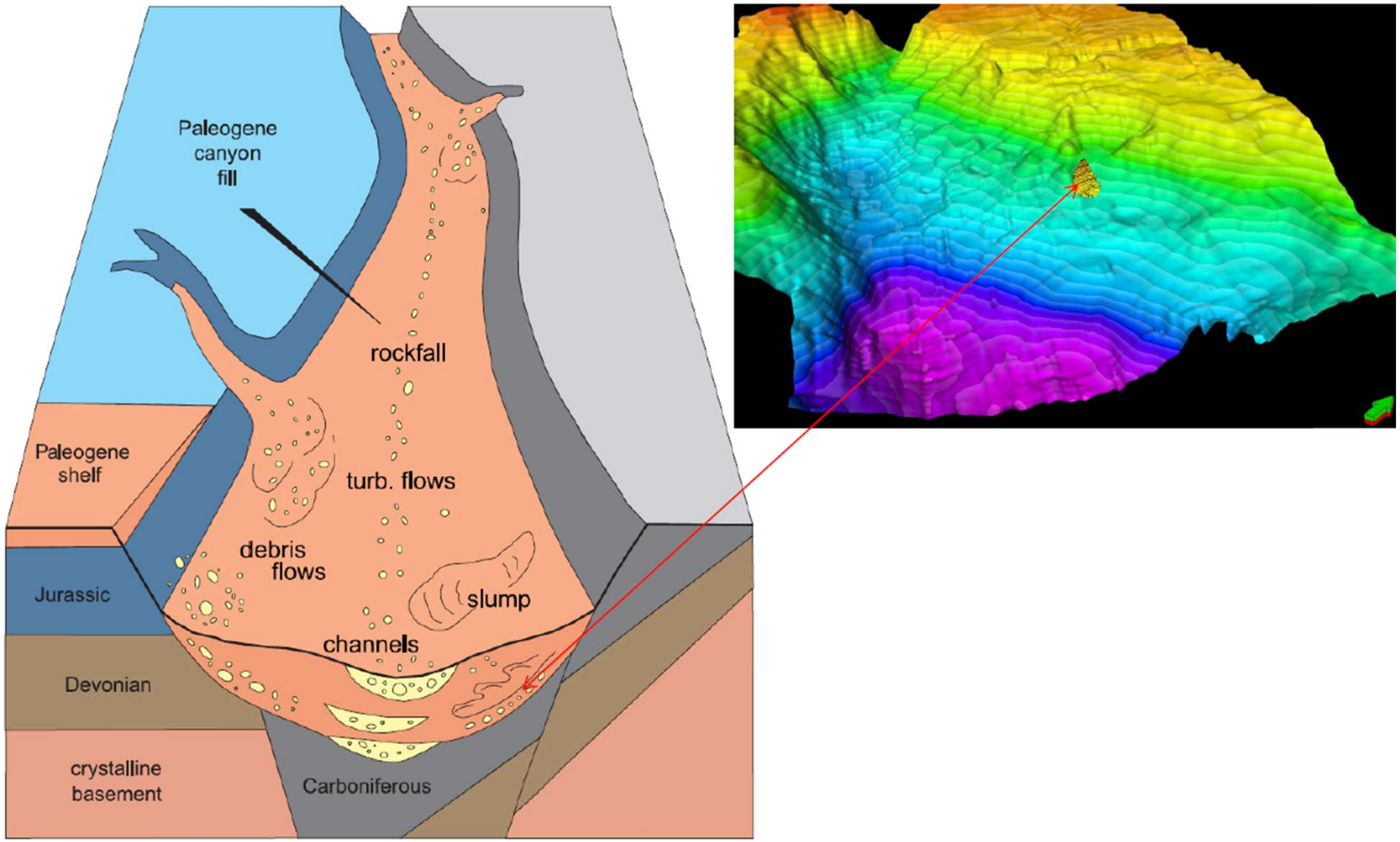

Figure 3.2.: Compilation of the schematic for the Nesvačilka Graben and Paleogene Valley with an actual operator's 3D seismic of the same. The target body is located on the north eastern slope of the valley and indicated with a red arrow.

Table 3.1.: Tabular summary of geological informations for well proposal ZA11

ZA 11	
Licence	Slopes of Bohemian Massif
Basin	Nesvačilka Paleogene Valley
Primary target (Play)	Basal Paleogene Clastics
Trap type	Stratigraphic (Pinchout)
Target depth	2,345 m TVD +/- 100 m
Total depth	2,480 m TVD +/- 100 m
Expected hydrocarbor	Oil
Nearby accumulation	Dambořice Oil field

Table 3.2.: Tabular summary of prognosed lithological sequence for well proposal ZA11

ZA 11 - Lithology Prognosis		
Formation Top - Bottom [m TVD]	**Stratigraphic Unit Name**	**Lithology**
0 - 1,780	Zdanice Unit	Alteration of sandstones and claystones
1,780 - 2,360	Autochthonous Paleogene	Predominantly pelites with clastic horizons on the base
2,360 - 2,480	Lower Carboniferous	Pelites

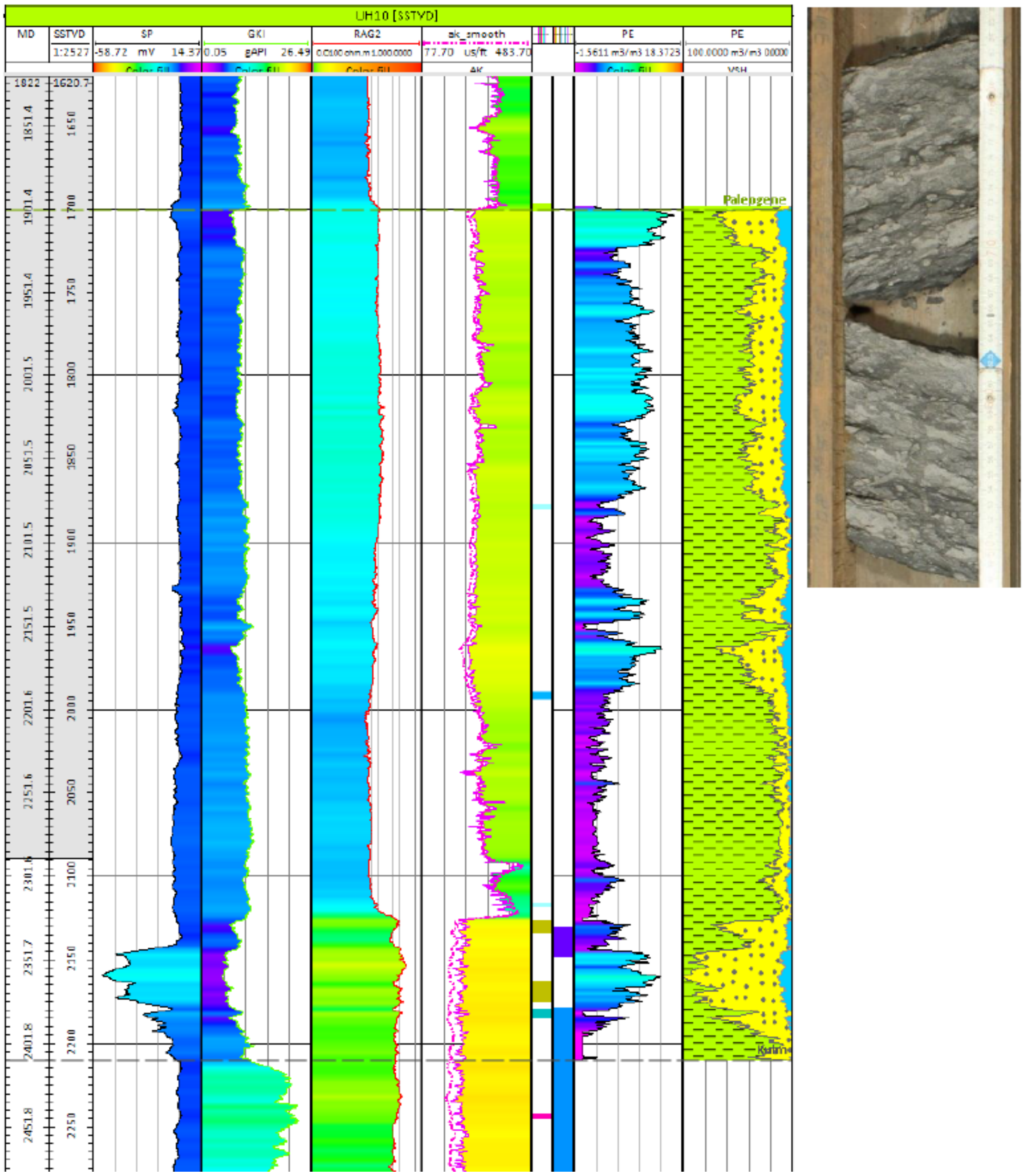

Figure 3.3.: Composite log and core image from offset well UH10. The top of the target BPC horizon is at 2,150 m, clearly indicated by the logs. The core image shows the coarse grained structure of the formation.

3.2. Well Design

3.2.1. Surface Location and Well Site

The surface location and the well site are defined, planned and provided by the operator. The target coordinates are situated below a national park were drilling is prohibited. Thus the operator planned the next nearby location with proper access to public roads. Figure 3.4 shows the surface location in vicinity to the town of Žarošice . The offset in surface and target location coordinates necessitates a slightly deviated well trajectory.

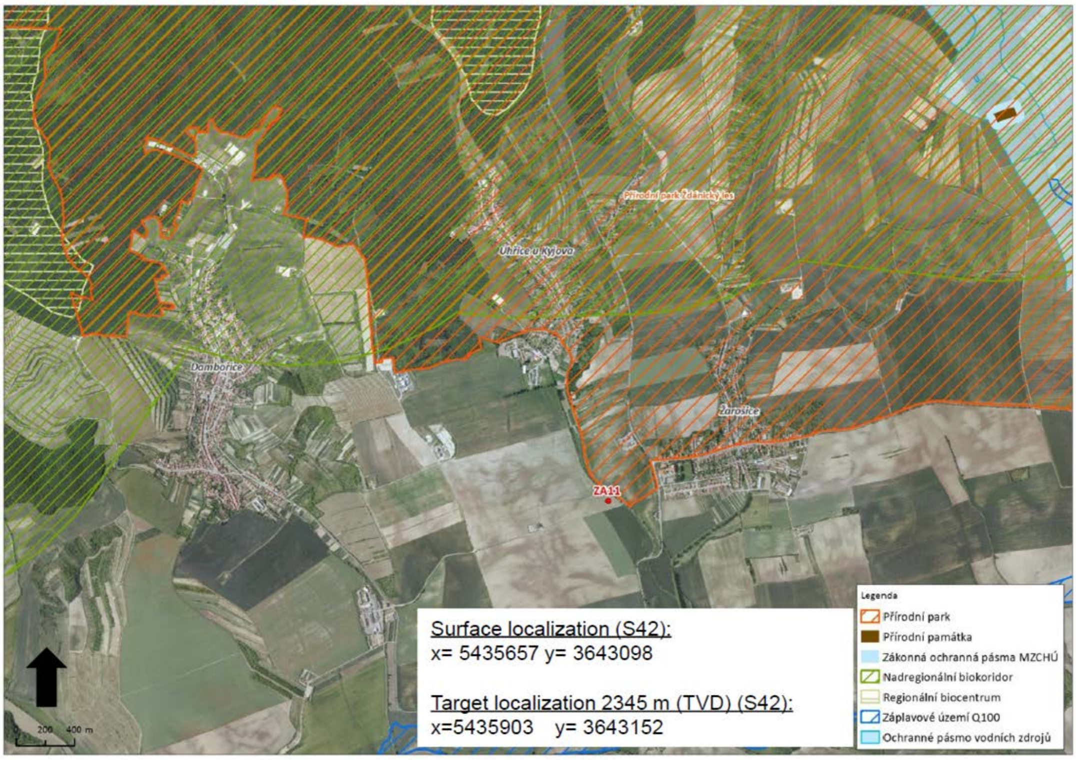

Figure 3.4.: Surface location of ZA11 next to the town of Žarošice . The red shaded area indicates a national park, below which the target is situated and drilling is prohibited. Thus a slightly deviated well trajectory is planned.

The well site is designed for a 160 t rig of the operator's preferred contractor, being a sister company. Figure 3.5 shows the planned layout for the anticipated rig. The inner area has an extent of approximately 80 m × 40 m resulting in 3,200 m^2 surface area demand.

Figure 3.5.: Layout of ZA11 well site for a 150 t rig, which is anticipated by the operator. The ínner area occupies an area of 3,200 m^2 which is more than double the required area of a LWDS rig.

3.2.2. Trajectory

As described in Section 3.2.1 the surface location and the target are not one above the other and thus a slightly deviated well trajectory is designed. It follows a Minimum Curvature design with a build rate of approximately 3 °/100 ft and a Kick Off Point (KOP) at 750 m, gaining a maximum inclination of 9.24°. Figure 3.6 shows the well trajectory for a well 2,500 mTVD Total Depth (TD) deep well design and Table 3.3 summarises the main well and trajectory parameters.

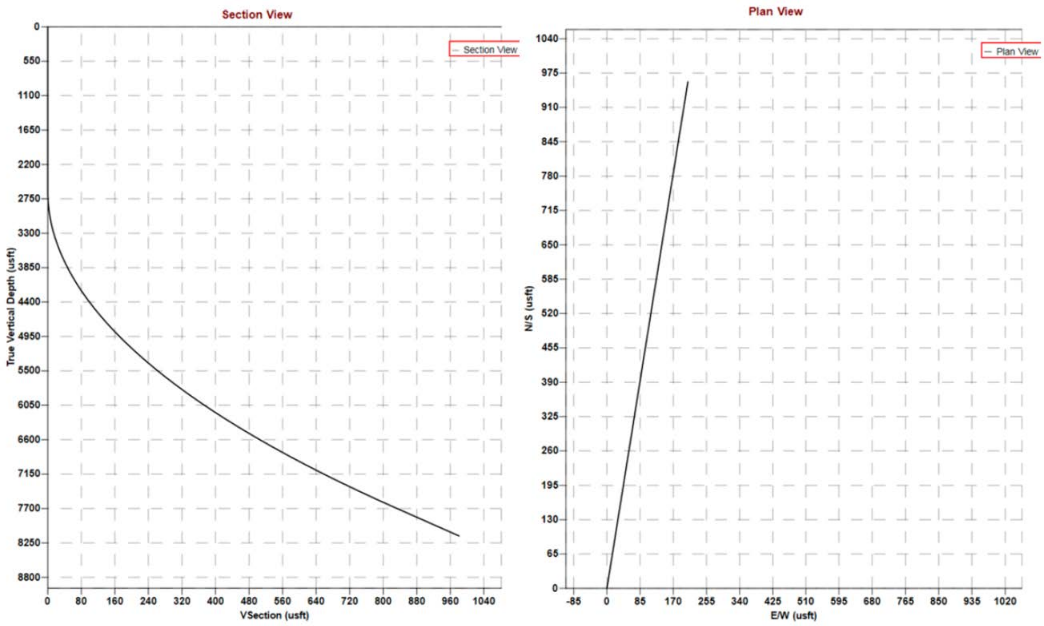

Figure 3.6.: Well trajectory for ZA11. Maximum step-out is 291 m with a total well depth of 2,500 mTVD.

3.2.3. Operator's Reference Casing Design

The operator has designed the well according to a Standard Clearance API approach, leading to three well sections, starting with a 13 3/8 in surface casing, continuing with a 9 5/8 in intermediate casing and a 7 in tapered (two qualities) production casing. Figure 3.7 illustrates the reference design. With this design the total weight of casing left in the hole is approximately 160 t worth approximately €145,000 based on the operator's assumptions.

Table 3.3.: Tabular summary of well trajectory details for ZA11

ZA 11 - Well Trajectory	
Surface Location Coordinates (S42 System)	X (S42) = 5,435,655.40 Y (S42) = 3,643,098.42
Depth Datum	Ground Level
Elevation above MSL	203.93 m
Well Target Formation	Basal Paleogene Clastics
Target depth	2345 m TVD
Target Location Coordinates (S42 System)	X (S42) = 5,435,903.00 Y (S42) = 3,643,152.00
Target Tolerance Radius	15 m
Projected Depth	2,480 +/- 100 m TVD 2,500 +/- 100 m MD
Kick Off Point	750 m
Build Rate	3 °/100 ft
Maximum Inclination	9.24°

3.2.4. LWDS Casing Design

Seven Basis of Design (BOD) options were evaluated for the LWDS casing design. They are summarised in Table B.5 and Figure 3.8 compares the total casing cost and the total casing weight left in the hole for each BOD. In the end the requirements set by the operator led to the final design proposal, which is BOD #7 and described in detail subsequently. These requirements included, that in case the well encounters economically recoverable hydrocarbons it has to enable a cased hole completion with a minimum tubing outer diameter of 2 3/8 in and a gas tight production casing with a preferred minimum drift diameter of 4 in. The operator expects a maximum production rate of 7 $\frac{m^3}{d}$.

By investigating Figure 3.8 one will notice that BOD #1 and #2 have a greater savings potential than the chosen option BOD #7. These two (BOD #1 and #2) options are based on non-standard oilfield sizes with very thin walls, for which the pipe vendor has no proper connectors developed yet. Thus the preferred option was BOD #7 due to its immediate availability. Nevertheless, BOD #1 and #2 should be considered for future development of dedicated LWDS pipes.

The design details of the chosen option BOD #7 are given in Table 3.4. With this parameters a load calculation was executed and the major results are presented in Table 3.5. In general it was accounted for worst case scenarios

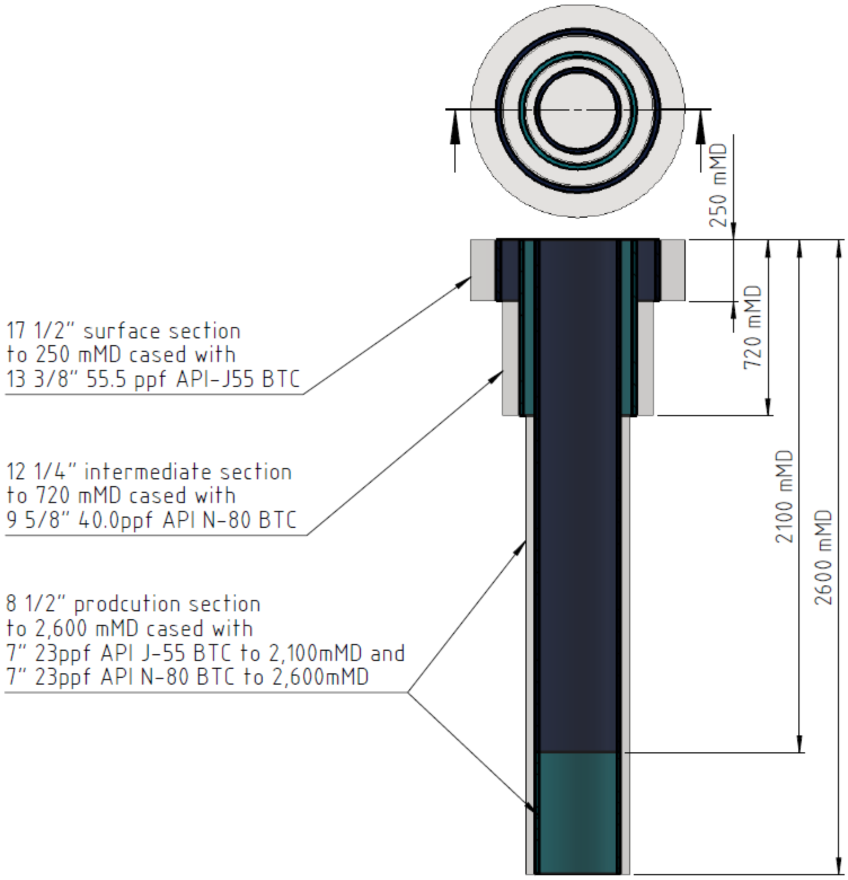

Figure 3.7.: Operator's reference well design for ZA11 according to API Standard Clearance approach. Light grey shaded are the hole sizes, dark blue and turquoise the casings. With this design the project is economically not feasible. Figure not to scale, horizontal exaggeration.

only if not specified differently in particular. The following scenarios were applied:

- A Gas Column scenario for burst loads.
- A Full Evacuation scenario for collapse loads.
- RIH, POOH, and ROB scenarios for tension loads.

The following assumptions were taken for the load calculations:

- A uniform pressure gradient of 9.0 ppg.
- A uniform mud weight gradient of 10.0 ppg in the surface section.
- A uniform mud weight gradient of 9.0 ppg in the production section.
- A uniform formation fracture pressure gradient of 15.0 ppg.

Figures 3.10 and 3.11 illustrate the load scenarios for the surface casing and Figures 3.12 and 3.13 for the production casing string. As the casing is also utilised for drilling, the torque loads are illustrated in the Drilling Programme section under 3.3. It has to be noted that all strings are designed with Grade 80 quality. If the safety factors are considered to be too low, the following options enhance the performance without increasing the total weight:

- Higher quality connectors can be applied in order to enhance torsional performance.
- Higher quality body and connectors can be applied in order to enhance burst, collapse, tensional, and torsional performance.

A contingency scenario was evaluated in case the well construction encounters insurmountable drilling problems. It was assumed the 5 in casing is cemented at 1,500 m and the well is drilled and cased with a 3 1/2 in 7.7 $\frac{\text{lb}}{\text{ft}}$ VAGT Grade 80 tubular to TD. The according hole size is 4 1/4 in. Load calculations are given in Appendix B.

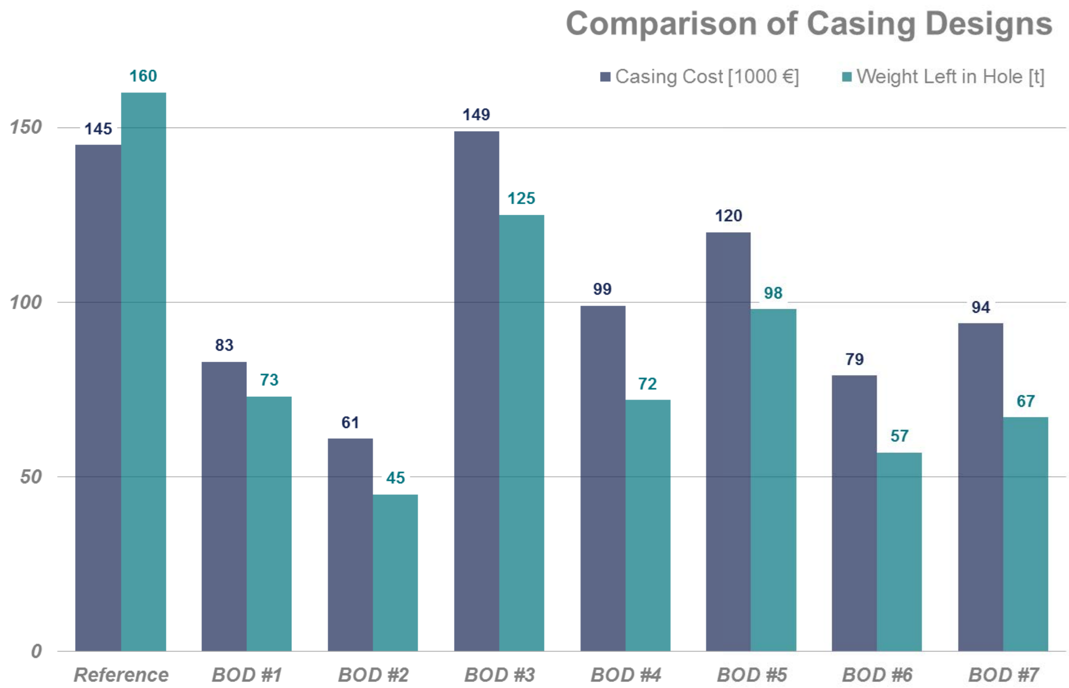

Figure 3.8.: Comparison of evaluated BODs for the well ZA11. BOD #7 was the final option. BOD #1 and #2 are based on non-standard oilfield sizes pipes out of API spectra.

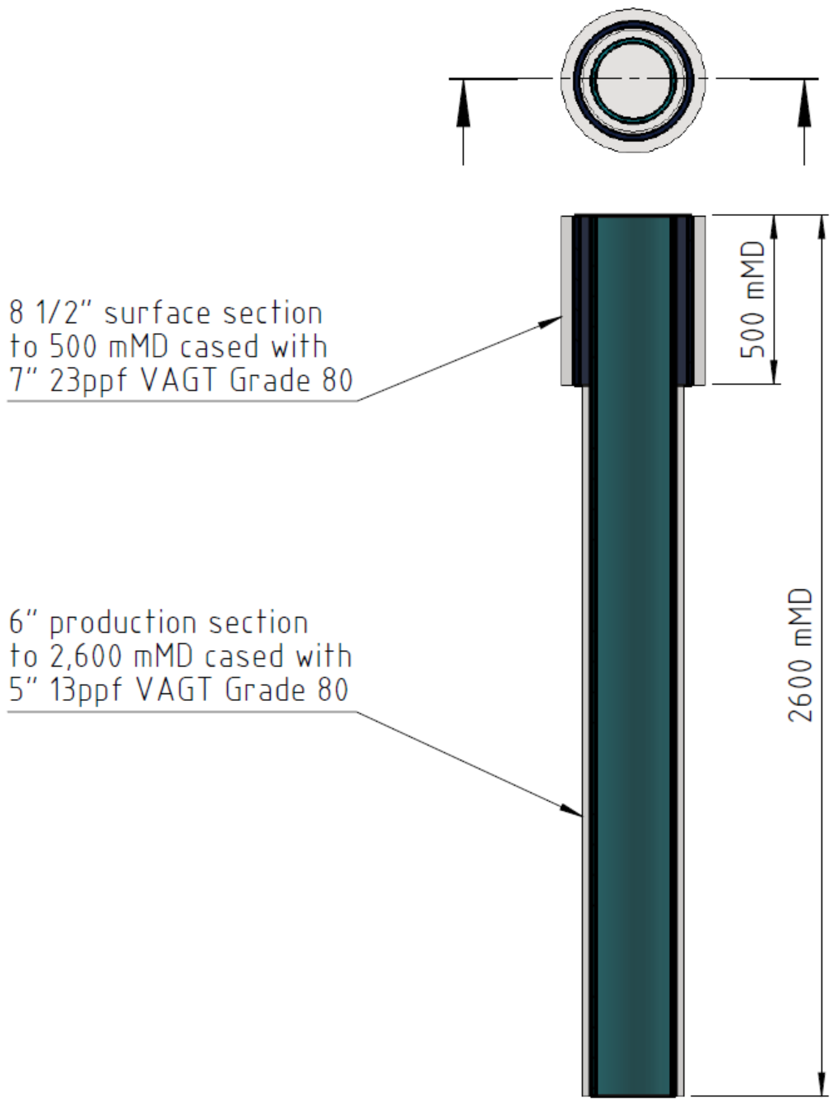

Figure 3.9.: Proposed BOD for ZA11. Surface casing is a 7 in LWDS tubular with 23 $\frac{\text{lb}}{\text{ft}}$ and the production casing is a 5 in LWDS tubular with 13 $\frac{\text{lb}}{\text{ft}}$. Figure not to scale, horizontal exaggeration.

Table 3.4.: Casing design details for proposed LWDS design.

LWDS Casing Design Details		
Property	**Surface Section**	**Production Section**
CasingType	VAGT Grade 80	VAGT Grade 80
Section Depth	500 mMD	2,600 mMD
Hole Size	8.500 in	6.000 in
Outer Diameter	7.000 in	5.000 in
Wall Thickness	0.317 in	0.253 in
Weight	23.0 lb/ft	13.0 lb/ft
Drift Diameter	6.241 in	4.369 in
YieldStrength	80,000 psi	80,000 psi
Burst Rating	6,343 psi	7,093 psi
Collapse Rating	3,829 psi	5,134 psi
Moment of Inertia	1.55E-05 m^4	4.44E-06 m^4
Total Casing Weight	17.1 t	50.2 t
Hole Volume	18.3 m^3	47.4 m^3
Top of Cement	both to surface	
Cement Volume (W/O Excess, incl. Shoe Track)	9.1 m^3	22.8 m^3
Dry Cement Weight (W/O Excess, incl. Shoe Track)	12.0 t	30.0 t
Mud Chemicals Weight (incl. Barite)	4.8 t	37.0 t
Estimated Casing Cost	€ 24,000.00	€ 70,000.00
Estimated Cement Cost	€ 600.00	€ 1,500.00
Estimated Mud Cost (W/O Water, and Disposal)	€ 3,000.00	€ 31,000.00

Table 3.5.: Summary of load calculation results for proposed LWDS design.

LWDS Casing Loads			
	Safety Factors		
Load Scenario	**Surface Section**	**Production Section**	**Contingency Section**
Burst (Gas Column)	6.0	1.3	1.5
Collapse (Full Evacuation)	1.6	1.8	2.2
Tension (RIH, POOH, ROB)	4.2	1.4	2.4

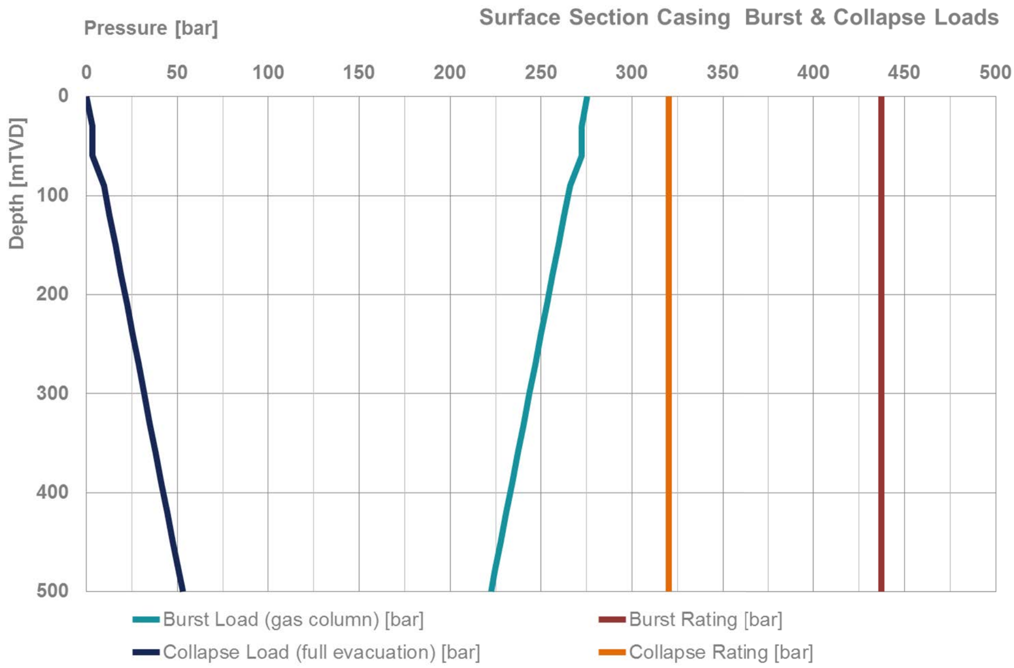

Figure 3.10.: Burst and collapse load profiles of surface section casing. Minimum safety factors are 1.6 for burst and 6 for collapse.

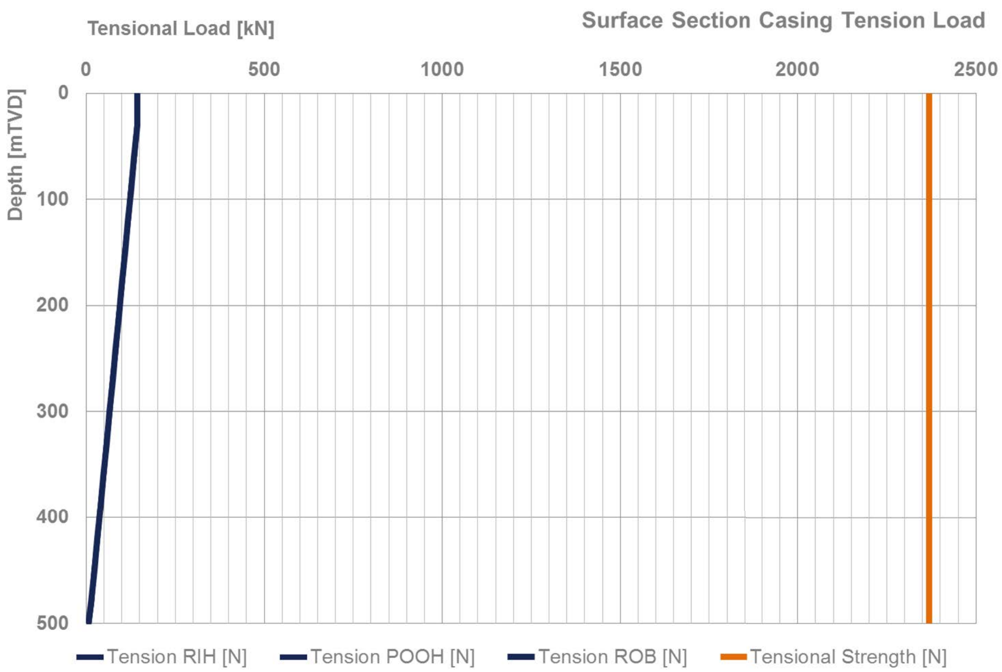

Figure 3.11.: Tension load profile of surface section casing. Minimum safety factor is 4.2 for tension. Due to the verticallity of the hole the curves for RIH, POOH, and ROB are overlain.

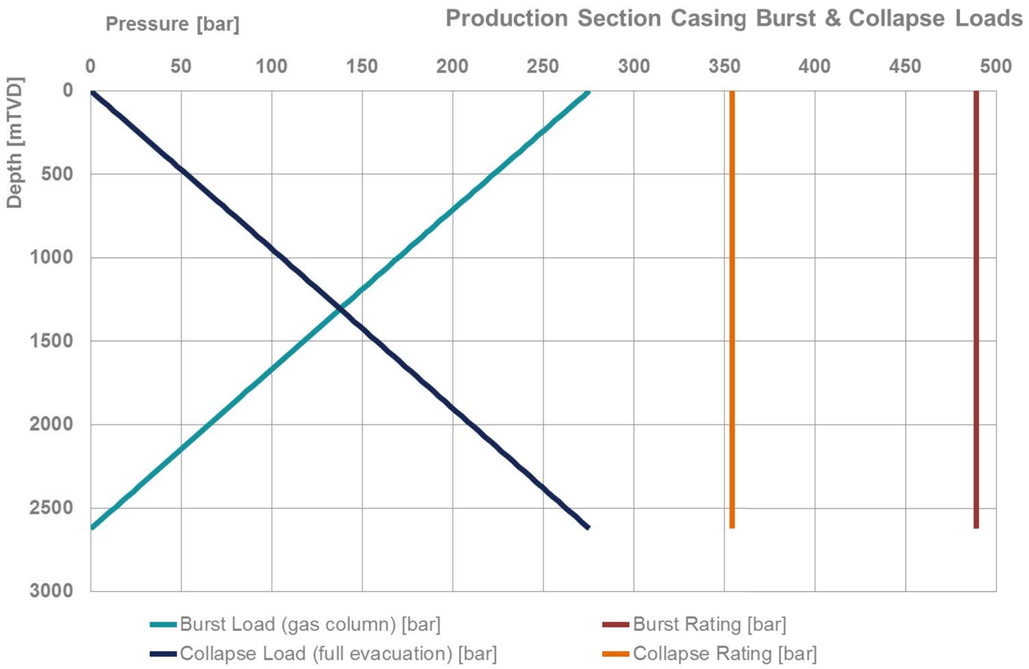

Figure 3.12.: Burst and collapse load profiles of production section casing. Minimum safety factors are 1.8 for burst and 1.3 for collapse.

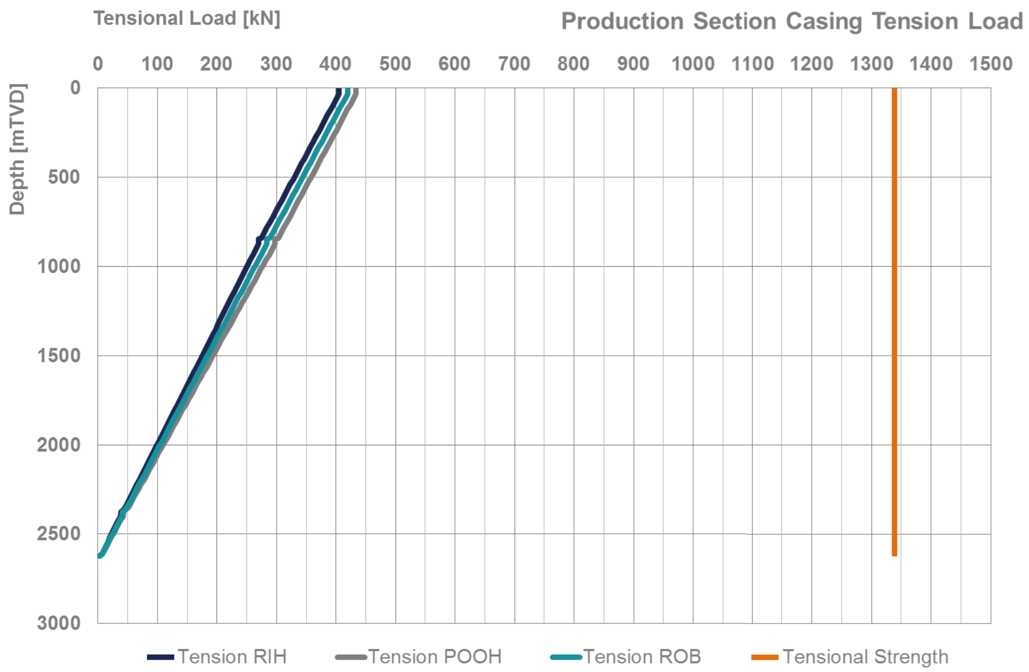

Figure 3.13.: Tension load profile of production section casing. Minimum safety factor is 3.1 for tension. Friction factors of 0.15 for cased hole and 0.30 for open hole are used.

3.3. Drilling Programme

3.3.1. Surface Section Drilling Programme

The surface section is drilled with the 7 in surface casing, for which details can be found under Section 3.2.4 in Table 3.4. A drill-able Casing while Drilling (CwD) bit with $8\,{}^{1}/_{2}$ in diameter is planned to drill to the section depth of 500 m. The gross Rate of Penetration (ROP) is estimated with 15 $\frac{\mathrm{m}}{\mathrm{h}}$. This is derived by investigation of a reference from the service company Odfjell Well Services. The company provided a record of 58 casing drilling jobs performed in Romania from 2012 to 2015. The overall average gross ROP is 17 $\frac{\mathrm{m}}{\mathrm{h}}$, with a maximum of up to 33 $\frac{\mathrm{m}}{\mathrm{h}}$. Figure 3.14 compares the average ROPs by casing size. Smaller diameters result in higher ROP.

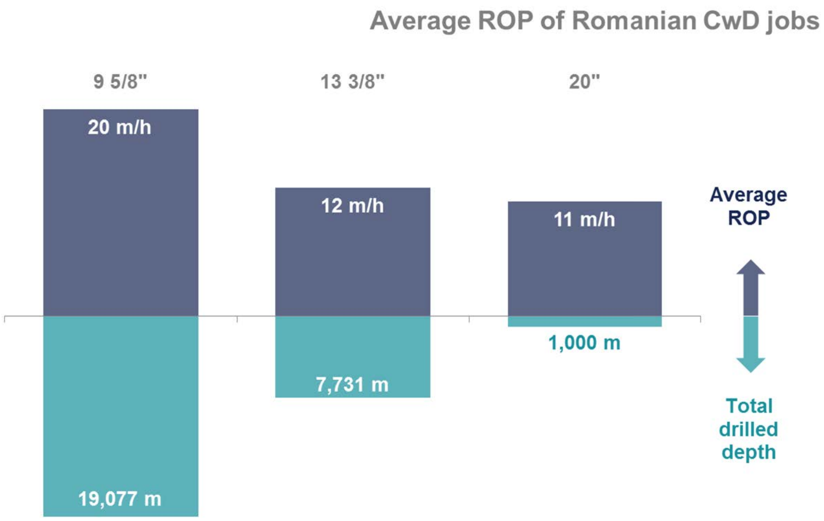

Figure 3.14.: Average ROP comparison of Romanian CwD jobs by casing size. The analysed job record was provided by company Odfjell Well Services and comprises 58 CwD jobs for various casing sizes. A trend is observable, that with reduced hole size the average ROP increases. Furthermore the learning effect seems to have an impact as by far most jobs have been performed with $9\,{}^{5}/_{8}$ in casing, with which the highest ROPs are achieved.

3.3.1.1. Critical Path Operations Plan

Table 3.6 shows the critical path operations planned for drilling the surface section. The surface section should be accomplished within three days, with the drilling operation being the longest single event with an estimated duration of more than 33 hours.

Table 3.6.: Critical path operations for surface section drilling. The bars in the "Duration" column illustrate graphically the planned operations duration. Drilling is the single major time consumer.

Critical Path Operations				
Step No.	Hole Depth mMD	Operation	Duration hours	Cumulative Duration days
0	0	Conductor Piling, Rig Up	Prior	Prior
0	0	Pre Spud Meeting	0.0	0.0
1	0	General Preperations, Mud preperation	8.0	0.3
2	0	R/U and test CwD equipment	8.0	0.7
3	0	START 8,5" Section	0.0	0.7
4	0	P/U Drilling Shoe Track with Casing Drilling Shoe 8,5" on 7" casing	3.0	0.8
5	500	Drill CwD 500 m with av. ROP of 15 m/hr	33.3	2.2
6	500	R/U Cementing equipment	1.0	2.2
7	500	Safety Meeting; p-Test	0.5	2.2
8	480	Cementation to surface and p-Test Casing	4.0	2.4
9	480	L/O Running tool joint and R/U Seal assebly	2.0	2.5
10	480	P-Test, R/D cementing equipment	1.0	2.5
11	480	N/U Wellhead and BOP	8.0	2.9
12	480	END 8,5" Section	0.0	2.9

3.3.1.2. Equipment

The operator anticipates to use a rig with the high level specifications given in Table 3.7. It is a mobile rig with 160 t hook load capacity. For the top hole section a diverter set is flanged on top of the conductor in order to manage shallow gas risk. The casing is rotated with a Casing Drive System (CDS) of internal or external grip type, attached to the Top Drive. An example CDS by Canadian manufacturer Volant Oil Tools Inc. is illustrated in Figure 3.15. This allows to rotate and circulate through the casing simultaneously and prevents the casing thread form damage that could occur when utilising an adapter ("Water Bushing") only. For tubular lifting a Single Joint Elevator is used and casing make-up can be done with the CDS. Nevertheless casing tongs shall be operational ready as a back up.

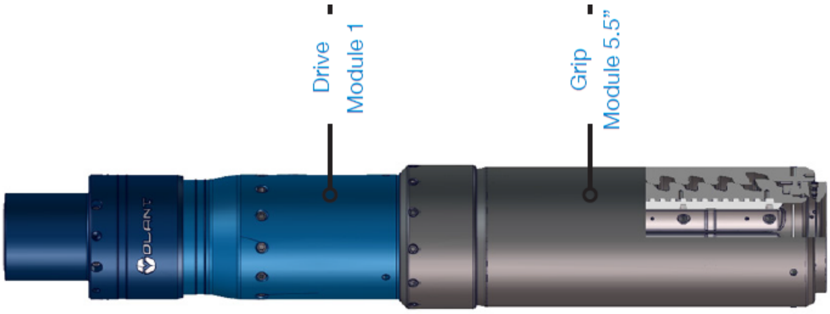

Figure 3.15.: Example of a Casing Drive System (CDS) by Volant. The Volant CRTe-1.0 is of External Grip type and can be dressed to drill with 5 in and 7 in casing. Image courtesy of Volant Oil Tools Inc..

Table 3.7.: Main rig specifications of the anticipated rig.

Rig Specifications	
Manufacturer	SBS, Austria
Hookload Capacity	160 t
Derrick Height	35.7 m
Engines	2 x 317 kW CATD3408B-DIT
Rotary Table Opening	27 ½ in
Substructure height	3.8 m
Top Drive	TESCO 250 HMIS
Top Drive max. continuous Drilling Torque	28,470 Nm
Mud Pumps	2 x IRI IDECO T 1000
Pressure Rating	345 bar
Mud Farm Capacity	108 m³

3.3.1.3. Drilling Loads

Axial and torsional load scenarios are illustrated in Figures 3.16 and 3.17. Pressure loads are the same as discussed in Chapter 3.2.4. From the tension profile one can see, that the overpull capacity is not limited by the casing but by the rig's hook load capacity. The maximum hook load is expected with 14.2 t, leaving theoretically more than 145 t of overpull capacity. The torsion profile shows that the torque capacity is limited by the Make Up (M/U) torque of 9.9 kNm. Theoretically this is the maximum applicable bit torque as the top hole is vertical. As mentioned in Section 3.2.4 this capacity can be enhanced by using higher quality connectors.

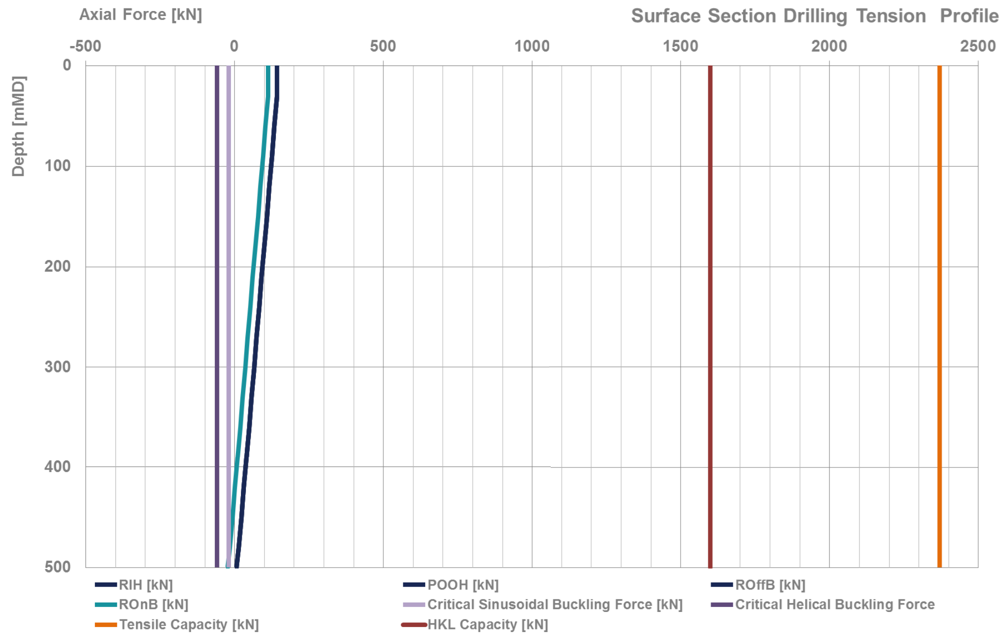

Figure 3.16.: Tension profile for surface section drilling with 7 in VAGT Grade 80 casing. Friction factors of 0.15 for cased hole and 0.3 for open hole are used. Due to the verticality of the top hole the RIH, POOH and ROffB curves are overlain. The ROnB curve is calculated with a WOB of 3 t applied.

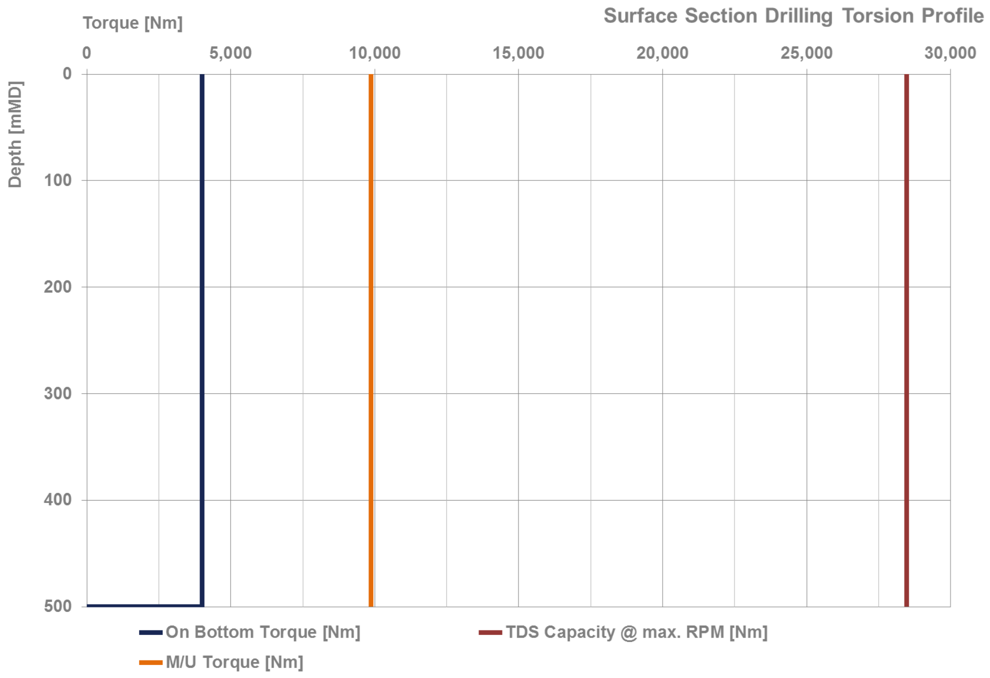

Figure 3.17.: Torsion profile for surface section drilling with 7 in VAGT Grade 80 casing. Due to the verticality of the top hole there is only the applied bit torque of 4 kNm evident.

3.3.1.4. Hydraulics

The pressure losses and the resulting Equivalent Circulating Densitys (ECDs) are calculated with the Bingham, the Herschel-Bulkley and the Nickens models. The Nickens model is based on Bode, Noffke, and Nickens, 1991 and was derived especially for slim hole drilling applications. It takes into account increased pressure loss due to pipe rotation and the increased pressure loss due to narrow annuli. A more comprehensive review on the model and the nature of the LWDS hydraulics in general can be read in Chapter 2. The surface section mud is a Bentonite spud mud with a density of 10 ppg. The basic mud parameters are listed together with a hydraulics summary in Table 3.8 and a detailed statement of the mud parameters is given in Appendix B. The maximum System Pressure Loss (SPL) is 120 bar, which is calculated with the Nickens model. It takes all mud pressure losses from entering the drill pipe to exiting at the bell nipple into account. A relatively high pressure loss of 100 bar across the BHA is applied, in order to have a safety margin, as the actual BHA design is not defined yet. The Herschel-Bulkley model, which is frequently also referred to as Modified Power-Law model underestimates the SPL by 12%. This underestimation increases with hole depth and reversely with annular clearance, evident in Section 3.3.2 under Figure 3.24.

Table 3.8.: Surface section hydraulics summary. The maximum pressure losses result from the Nickens model. Relatively high BHA pressure loss of 100 bar accounts for safety margin, due to yet undefined Wireline BHA design.

Surface Section Hydraulics Summary	
Mud Type	Bentonite Spud Mud
Mud Density	10.0 ppg
Yield Point	40 lb/100ft²
Viscosity	14 cp
Flow Rate	1.000 litres/min
Open Hole Volume	27 m³
Assumed Pressure Loss across BHA	100 bar
Maximum ECD at surface	12.9 ppg
Total System Pressure Loss (W/O Surface Lines)	120 bar
Estimated Weight of Mud Chemicals	4.8 t
Estimated Cost of Mud Chemicals	€ 4,000

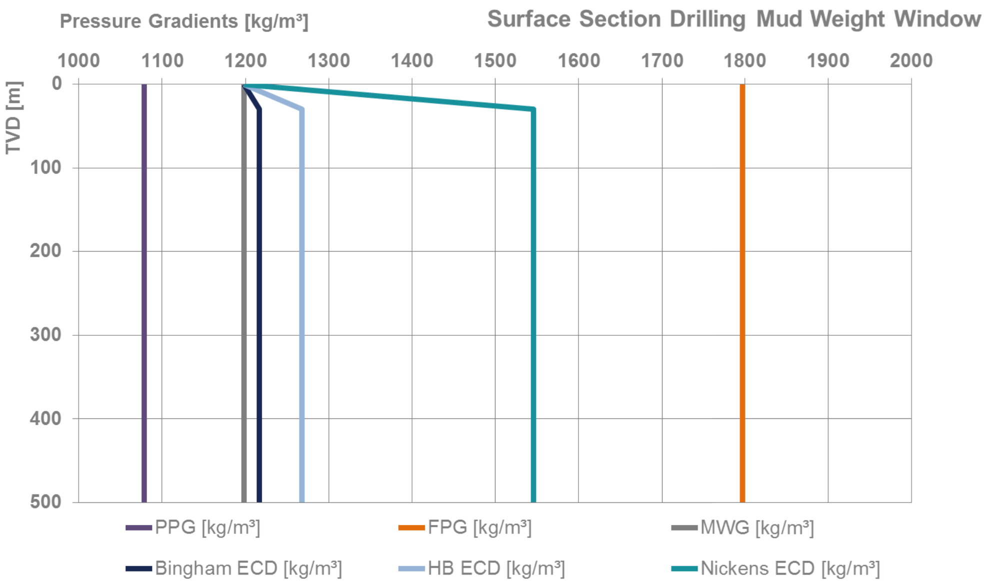

Figure 3.18.: Mud weight window for surface section drilling. ECDs are calculated with Bingham, Herschel-Bulkley, and Nickens models.

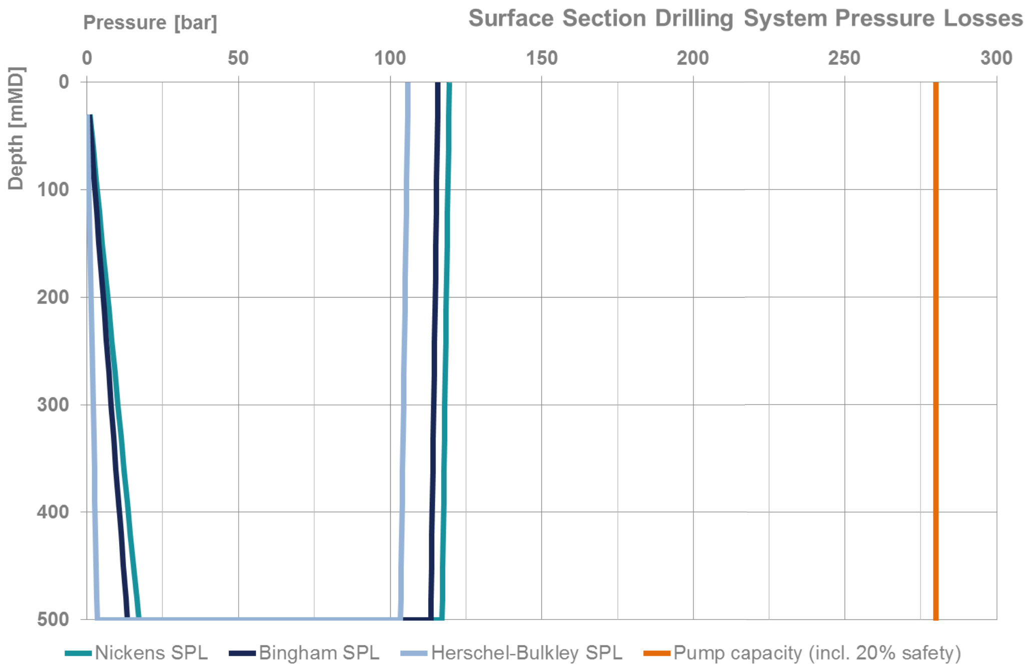

Figure 3.19.: System pressure losses for surface section drilling according to Bingham, Herschel-Bulkley, and Nickens. Nickens has the highest SPL. A pressure loss across the BHA and bit is assumed with 100 bar. The right slope indicates pipe pressure losses, then the horizontal linear indicates the bit and BHA losses and the left slope indicates the annular pressure losses.

3.3.1.5. Drilling Hazards

The offset well UH10 showed a shallow gas occurrence at 300 m depth. The probability of encountering the same gas bearing layer is low due to the very low aerial extent of the shallow gas occurrences in this region. Nevertheless, as discussed in Section 3.3.1.2 a diverter stack shall be flanged on the conductor to allow for safe diverting and flaring in case of shallow gas.

3.3.1.6. Cementation

A one stage cementation job according to Table 3.9 is planned. Float and Landing Collars are part of the casing drilling shoe track. The pre-flush spacer fluid should be designed carefully in order to achieve optimum filter cake removal and zonal isolation. Its design is not in the scope of this thesis, but represents a potential future area of research. The second plug is displaced with drilling mud.

Table 3.9.: Surface section cementing plan.

Surface Section Cementing				
Type	**Grade**	**Volume**	**Weight**	**Pump Rate**
Lead	Class G	7 m³	1.60 SG	600 litre/min
Tail	Class G Gassbloc	3 m³	1.90 SG	400 litre/min

3.3.2. Production Section Drilling Programme

The production section is drilled with the 5 in production casing, for which details can be found under Section 3.2.4 in Table 3.4. The casing is equipped with a 6 in LWDS Dual-Body Bit, enabling to run LWDS wireline BHAs through the center of it or to drill in coring mode with a core barrel latched into the casing. The surface casing drift diameter would allow to increase the bit diameter to even 6.2 in. It is planned to drill out the cement and perform a Leak-Off Test (LOT) with a full-hole LWDS BHA and then switch to a directional LWDS BHA for drilling just above the reservoir. After this it is planned to core through the reservoir with two core barrel trips and subsequently to drill full-hole to TD. For this section an MPD system is utilised in order to have very accurate control of the hydraulics and so enable safe well control in case of influx scenarios.

3.3.2.1. Critical Path Operations Plan

The total section duration for the production section is estimated with 10.9 days resulting in a total drilling duration of 13.8 days. The single major time consumer is full-hole drilling to coring depth with 156 hours at an average gross ROP of 15 $\frac{\mathrm{m}}{\mathrm{h}}$. Other major time consumers are rig up of the MPD equipment and cased hole wireline logging.

Table 3.10.: Critical path operations for production section drilling. The bars in the "Duration" column illustrate graphically the planned operations duration. Drilling is the single major time consumer.

Step No.	Hole Depth mMD	Operation	Duration hours	Cumulative Duration days
13	480	START 6" Section	0.0	2.9
14	480	R/U and Test MPD Rotating Equipment	16.0	3.5
15	480	P/U Drilling Shoe Track with Ring Bit Shoe 6" with Full Hole Bit Insert on 5" csg	3.0	3.7
16	480	RIH (Tripping Speed 300 m/h)	1.6	3.7
17	505	Drill out shoe track and new formation	5.0	3.9
18	505	LOT	0.5	4.0
19	505	Pull Full Hole Bit Insert (Pull Speed 1,000 m/h)	0.5	4.0
20	505	P/U, pump down and latch Directional LWDS BHA 8,5" bit	4.0	4.1
21	2,340	LWDS CwD above reservoir depth 2340 m (Gross ROP 15 m/h)	156.0	10.6
22	2,340	B/U cleaning; Flow check	2.0	10.7
23	2,340	R/U Wireline with Pressure Cntrl. Equip., Pull LWDS Directional BHA	4.0	10.9
24	2,375	Drop Core Barrel #1 (Drop Speed 3,000 m/h)	2.0	11.0
25	2,384	Drill Core #1 (ROP 12 m/h)	0.8	11.0
26	2,384	R/U WL with P Control Equip., Retrieve Core #1, circulate to prevent Swabbing (Pull Speed 1,000 m/h)	3.0	11.1
27	2,384	Drop Core Barrel #2 (Drop Speed 3,000 m/h)	2.0	11.2
28	2,393	Drill Core #2 (ROP 12 m/h)	0.8	11.3
29	2,393	R/U WL with P Control Equip., Retrieve Core #2, circulate to prevent Swabbing (Pull Speed 1,000 m/h)	3.0	11.4
30	2,393	Drop Full Hole Bit Insert (Drop Speed 3,000 m/h)	2.0	11.5
31	2,600	Drill to TD (ROP 12 m/h)	17.3	12.2
32	2,600	Clean B/U; Retrieve BHA; L/D BHA (Pull Speed 1,000 m/h)	2.6	12.3
33	2,600	Deploy Float Shoe and Collar (Drop Speed 3,000 m/h)	0.9	12.3
34	2,600	Hang off casing with Mandrel Hanger	3.0	12.5
35	2,600	R/U Cementing equipment	3.0	12.6
36	2,600	Safety Meeting; p-Test	0.5	12.6
37	2,600	Cementation	8.0	12.9
38	2,600	WOC; R/D cementing service, L/O running tool, R/U Seal Assy	3.0	13.1
39	2,600	CH WL Logging 3 runs incl. R/U, R/D and safety meeting	18.0	13.8
40	2,600	END 6" Section	0.0	13.8

3.3.2.2. Equipment

For drilling of the production section the same rig as for the surface section is utilised. In this section the casing is also rotated from top with a CDS. CDS types are available that allow for redressing the CDS for the actual pipe size. For enabling safe well control an MPD system shall be applied. Figure 3.20 shows a typical set-up of an MPD system by Weatherford International plc.

Main components are the Rotating Control Device (RCD), which is flanged on top of the BOP stack and the control manifold, usually equipped with sensitive flow measurement devices. With this system the mud weight can be lowered, allowing for higher pump rates and better hole cleaning, thus improving drilling performance. For directional control it is assumed to drill with a small diameter RSS in order to have the best drilling performance.

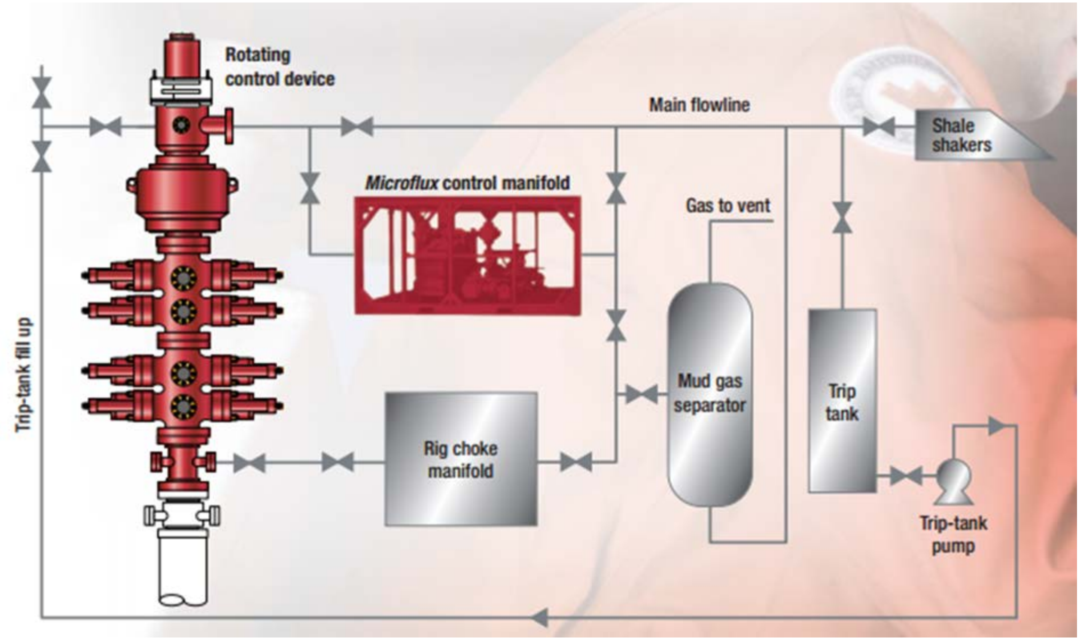

Figure 3.20.: Example illustration of an MPD system. Image courtesy of Weatherford International plc.

3.3.2.3. Drilling Loads

Axial and torsional load scenarios are illustrated in Figures 3.21 and 3.22. Pressure loads are the same as discussed in Chapter 3.2.4. From the tension profile one can see, that the overpull capacity is limited by the casing tensile load capacity. The maximum hook load is expected at TD during POOH with 44 t, leaving 90 t of overpull capacity theoretically. The torsion profile shows that the torque capacity is limited strongly by the M/U torque. With a bit torque of 3 kNm the surface torque is estimated with 4 kNm, leaving a torsional capacity of 2.5 kNm. As mentioned in Section 3.2.4 this capacity can be enhanced by using higher quality connectors.

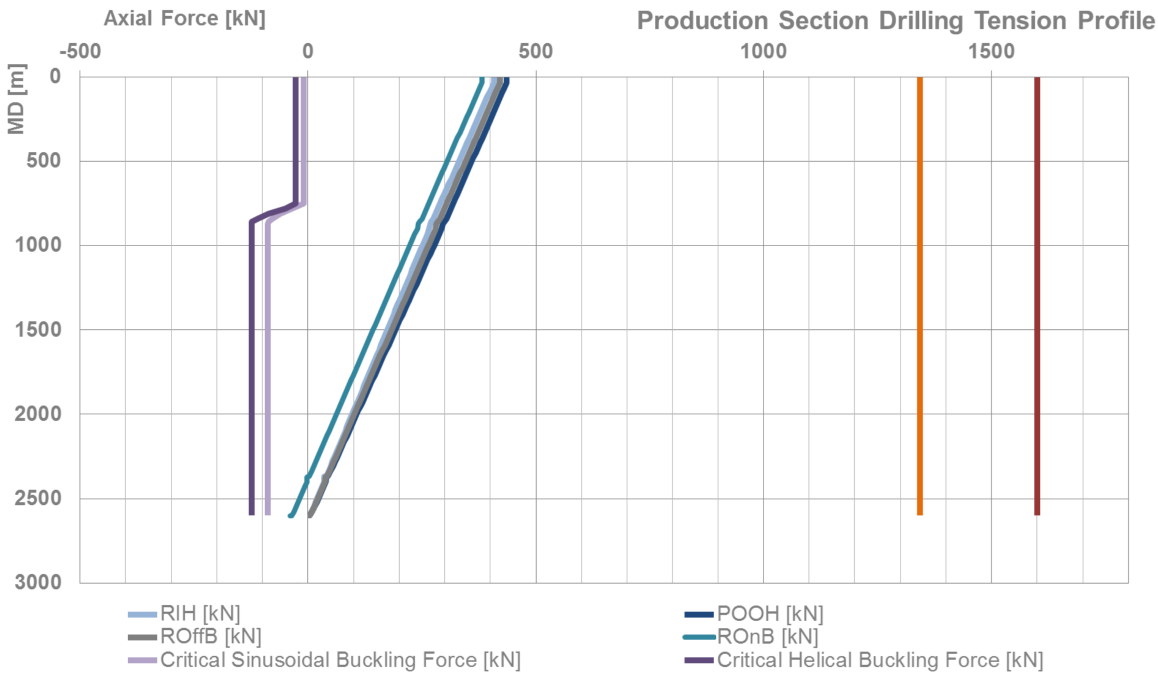

Figure 3.21.: Tension profile for production section drilling with 5 in VAGT Grade 80 casing. Friction factors of 0.15 for cased hole and 0.3 for open hole are used. Due to the low inclination of the section the RIH, POOH and ROffB do not differ largely. The ROnB curve is calculated with a WOB of 3 t applied.

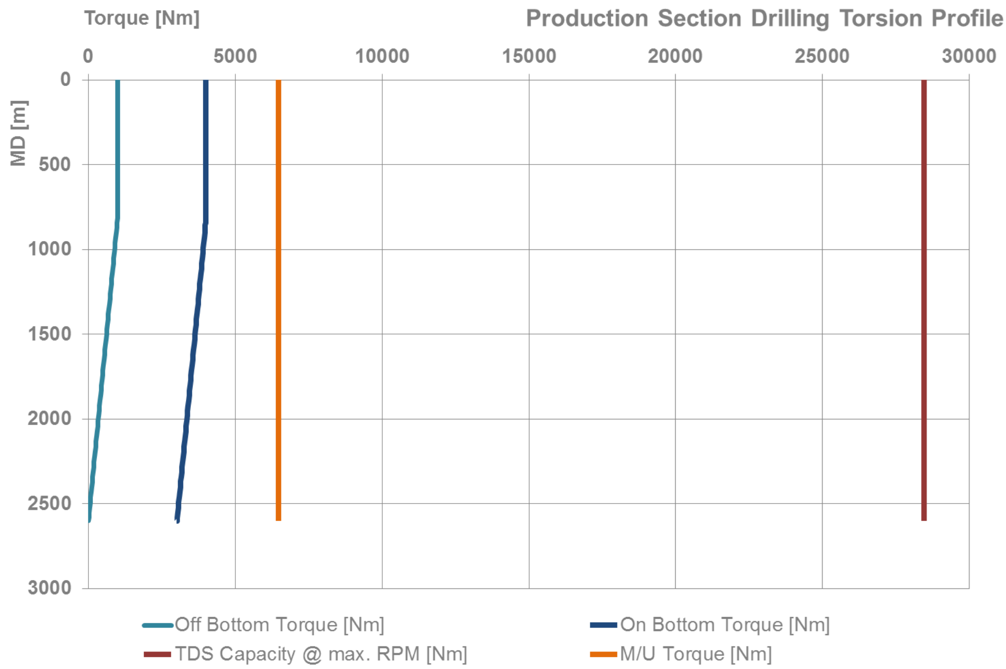

Figure 3.22.: Torsion profile for production section drilling with 5 in VAGT Grade 80 casing. A bit torque of 3 kNm is applied.

3.3.2.4. Hydraulics

Same as for the surface section, for the production section the pressure losses and the resulting ECDs are calculated with the Bingham, the Herschel-Bulkley and the Nickens models. The surface section mud is an advanced Potassium Chloride (KCl) Polymer water based mud system with a density of 9 ppg. The basic mud parameters are listed together with a hydraulics summary in Table 3.11 and a detailed statement of the mud parameters is given in Appendix B. The maximum SPL is 273 bar, which is calculated with the Nickens model. It takes all mud pressure losses from entering the drill pipe to exiting at the bell nipple into account. A relatively high pressure loss of 100 bar across the BHA is applied in order to have a safety margin, as the actual BHA design is not defined yet. The Herschel-Bulkley model, which is frequently also referred to as Modified Power-Law model underestimates the SPL by 49%.

Table 3.11.: Production section hydraulics summary. The maximum pressure losses result from the Nickens model. Relatively high BHA pressure loss of 100 bar accounts for safety margin, due to yet undefined Wireline BHA design.

Production Section Hydraulics Summary	
Mud Type	KCl Polymer Mud
Mud Density	9 ppg
Yield Point	40 lb/100ft²
Viscosity	14 cp
Flow Rate	450 litre/min
Open Hole Volume	48 m³
Assumed Pressure Loss across BHA	100 bar
Maximum ECD at previous shoe	11 ppg
Total System Pressure Loss (W/O Surface Lines)	273 bar
Estimated Weight of Mud Chemicals	37 t
Estimated Cost of Mud Chemicals	€ 31,000

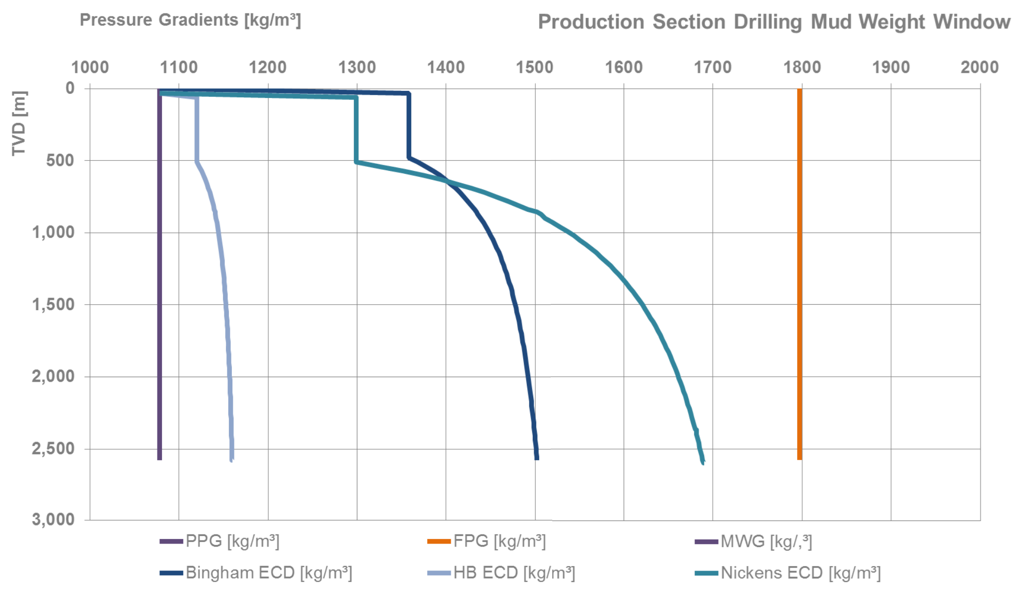

Figure 3.23.: Mud weight window for production section drilling. ECDs are calculated with Bingham, Herschel-Bulkley, and Nickens models.

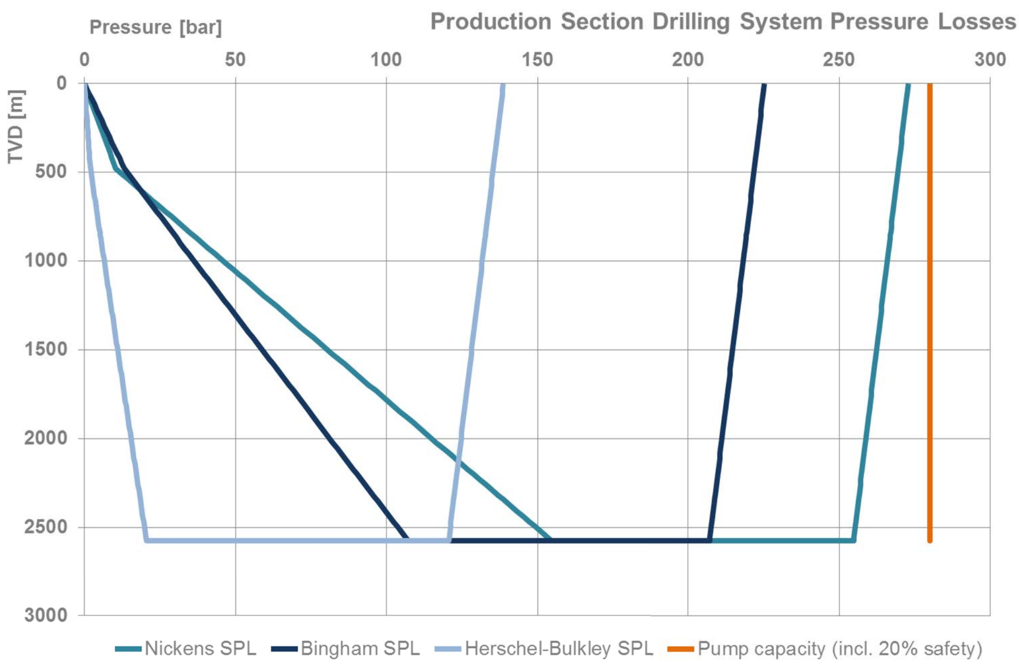

Figure 3.24.: System pressure losses for production section drilling according to Bingham, Herschel-Bulkley, and Nickens. Nickens has the highest SPL. A pressure loss across the BHA and bit is assumed with 100 bar. The chart may be read from right to left, starting with the maximum surface pressure. The right slope indicates pipe pressure losses, then the horizontal linear indicates the bit and BHA losses and the left slope indicates the annular pressure losses.

3.3.2.5. Drilling Hazards

Shallow Gas If shallow gas was experienced on the previous section and the casing had to be set shallower than planned, the mud weight for this section may be raised.

Kick Tolerance The pre-calculated low Kick Tolerance of 0.28 m^3 in this section is the main reason why an MPD system is proposed for reactive well control and drilling balanced. The calculation is shown in Table 3.12. A LOT has to be performed as indicated in Section 3.3.2.1 immediately after drilling out the shoe and five metre of formation. With this determined Leak-Off pressure a new Kick Tolerance calculation shall be performed and the MPD system adjusted.

Table 3.12.: Calculation of Kick Tolerance for production section drilling. The low value calculated results in the proposed MPD utilisation.

Kick Tolerance Calculation (W/O MPD)		
Shoe depth	500	m
Section depth	2600	m
Mud Weight	9	ppg
Kick Intensity	0.5	ppg
Gas Gradient	0.1	psi/ft
Fracture Pressure @ Shoe	90	bar
Overbalanced formation pressure	296	bar
Surface Pressure Safety Factor	100	psi
MAASP	29	bar
Max. height of kick	165	m
Kick volume @ influx at bottom	0.92	m^3
Kick volume @ influx below shoe	**0.28**	**m^3**

3.3.2.6. Cementation

A one stage cementation job according to Table 3.13 is planned. Float and Landing collars are pumped down. The pre-flush spacer fluid should be designed carefully in order to achieve optimum filter cake removal and zonal isolation. Its design is not in the scope of this thesis, but represents a potential future area of research. The second plug is displaced with drilling mud.

Table 3.13.: Surface section cementing plan.

Production Section Cementing				
Type	**Grade**	**Volume**	**Weight**	**Pump Rate**
Lead	Class G	20 m^3	1.60 SG	200 litre/min
Tail	Class G Gassbloc	5 m^3	1.90 SG	100 litre/min

3.4. Time and Cost Estimation

With the established operations plan given in Sections 3.3.1.1 and 3.3.2.1, the well is drilled to TD in less than 14 days with a cumulative cost of EUR 1.1 million. Figure 3.25 illustrates the time and cost evolution against the cumulative time and Figure 3.26 illustrates the breakdown of these costs into cost categories. Appendix B contains a more detailed cost breakdown. The total cost of the well including completions and well test is estimated with EUR 1.2 million. The major cost driver is due to the high technical effort the cost for services, which can not be covered by the drilling contractor. These costs are broken down in more detail in Figure 3.27. The MPD cost ranks highest followed by the combined cost for casing drilling and handling service. Nevertheless, a fully integrated LWDS concept also integrates these technologies and would operate without these services provided by third parties.

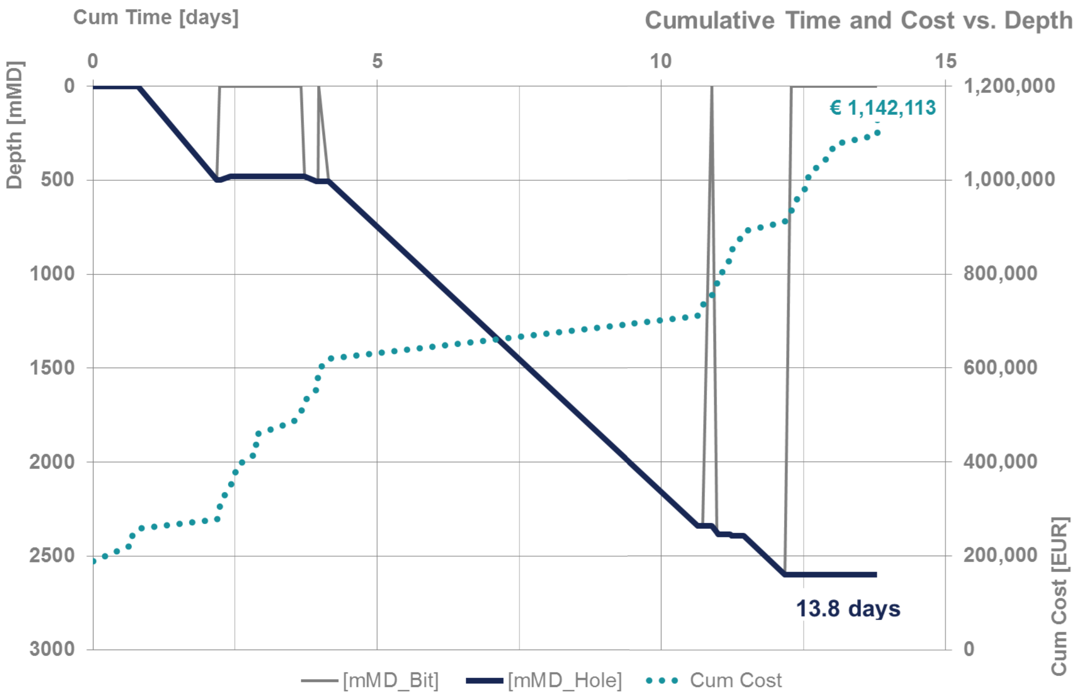

Figure 3.25.: Time and cost versus depth estimation of LWDS well proposal

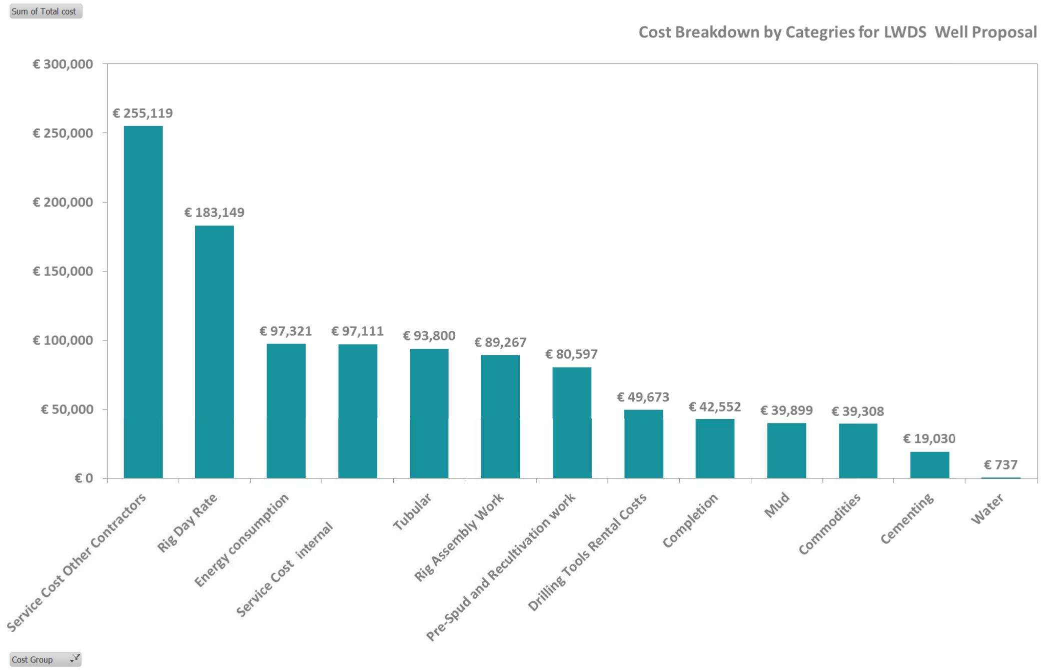

Figure 3.26.: Cost breakdown according to categories. The largest cost driver is the service cost for other contractors, which results from the technically demanding operations.

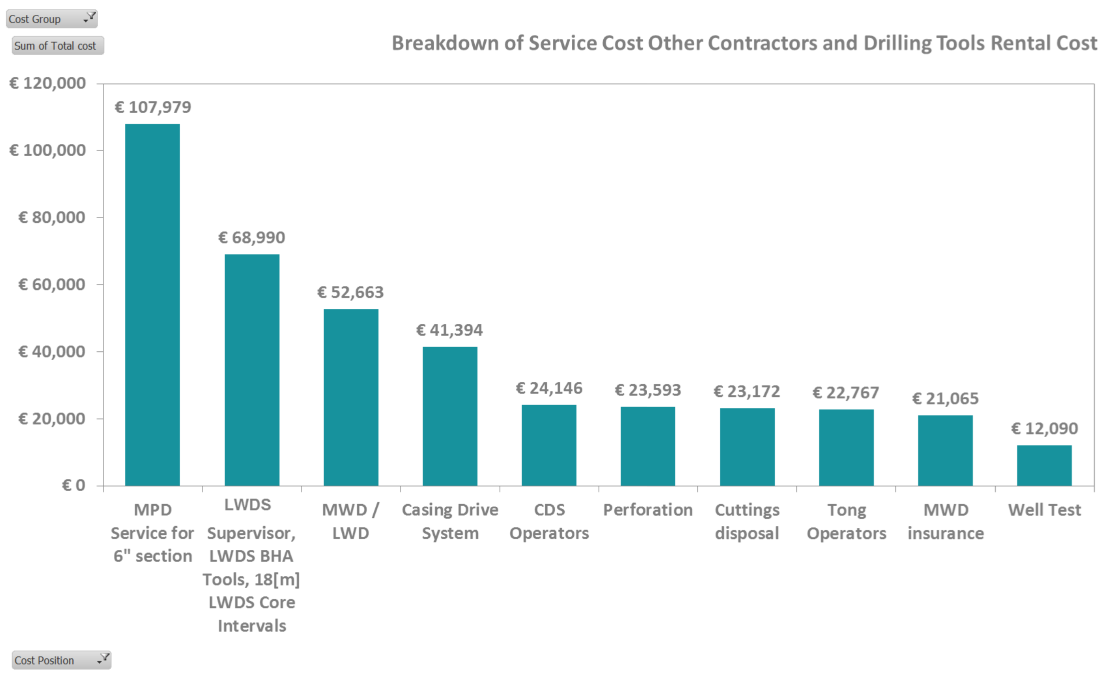

Figure 3.27.: Cost breakdown of costs related to external services. MPD service is the most costly application.

3.5. Comparison

3.5.1. Well Design Comparison

Figure 3.28 compares directly the operator's reference well design with the LWDS proposed well design. The LWDS well would fit completely into the reference design. With this design 56% savings in string weight, 65% savings in mud and cuttings volume, and 74% savings in cement volume are identified.

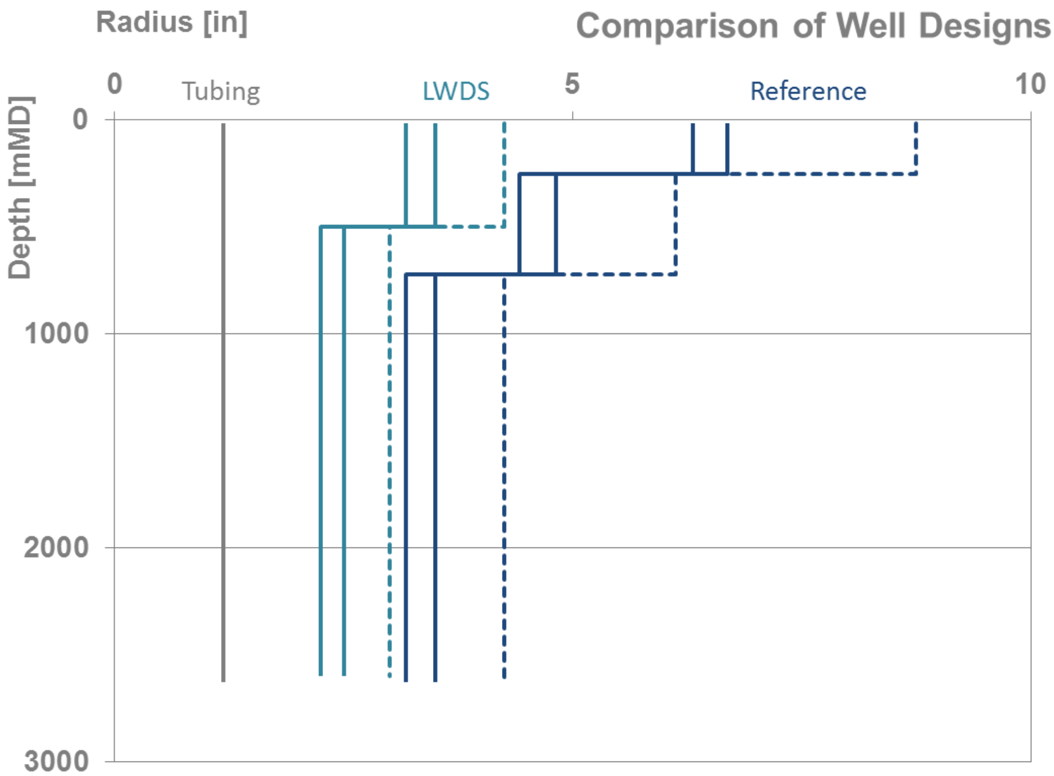

Figure 3.28.: Comparison of reference well design (dark blue) and the proposed LWDS well design (torquise). Casings are all to surface but for better illustration purposes they are drawn only from the previous shoe on. Solid lines indicate casing inner and outer diameter respectively. Dashed lines indicate hole diameters.

Table 3.14.: Summary of reference design key parameters and LWDS design key parameters with savings potential column on the very right.

Well Design Details Comparison										
Parameter	**Unit**	**Reference Casing Design Total**	**Reference Surface Section**	**Reference Intermediate Section**	**Reference Production Section**		**LWDS Casing Design Total**	**Surface Section**	**Production Section**	**SAVINGS**
CasingType			API J-55 BTC	API N-80 BTC	API J-55 BTC	API N-80 BTC		VAGT Grade 80	VAGT Grade 80	
Section Depth	mMD		250	720	2,100	2,600		500	2,600	
Hole Size	in		17.500	12.250	8.500	8.500		8.500	6.000	
Outer Diameter	in		13.375	9.625	7.000	7.000		7.000	5.000	
Wall Thickness	in		0.380	0.395	0.317	0.317		0.317	0.253	
Weight	lb/ft		54.5	40.0	23.0	23.0		23.0	13.0	
Drift Diameter	in		12.45875	8.67875	6.241	6.241		6.241	4.369	
Yield Strength	psi		55,000	80,000	55,000	80,000		80,000	80,000	
Burst Rating	psi		2,741	5,742	4,365	6,337		6,343	7,093	
Collapse Rating	psi		1,131	3,089	3,263	3,828		3,829	5,134	
Moment of Inertia	m^4		1.36E-04	5.09E-05	1.55E-05	1.55E-05		1.55E-05	4.44E-06	
Casing Weight	t	**151.8**	20.2	42.8	71.7	17.1	**67.3**	17.1	50.2	**56%**
Hole Volume	m^3	**188.7**	38.8	54.7		95.2	**65.7**	18.3	47.4	**65%**
Top of Cement			cemented to surface					cemented to surface		
Cement Volume (W/O Excess, incl. Shoe Track)	m^3	**120.7**	13.1	37.4		70.2	**31.9**	9.1	22.8	**74%**
Dry Cement Weight (W/O Excess, incl. Shoe Track)	t	**158.9**	17.3	49.2		92.4	**42.0**	12.0	30.0	**74%**
Mud Chemicals Weight (incl. Barite)	t	**114.0**	5.0	2.0		107.0	**41.8**	4.8	37.0	**63%**
Estimated Casing Cost		**€ 145,000.00**	€ 19,000.00	€ 48,000.00	€ 59,000.00	€ 19,000.00	**€ 94,000.00**	€ 24,000.00	€ 70,000.00	**35%**
Estimated Cement Cost		**€ 8,000.00**	€ 900.00	€ 2,400.00		€ 4,700.00	**€ 2,100.00**	€ 600.00	€ 1,500.00	**74%**
Estimated Mud Cost (W/O Water, and Disposal)		**€ 93,000.00**	€ 3,000.00	€ 2,000.00		€ 88,000.00	**€ 34,000.00**	€ 3,000.00	€ 31,000.00	**63%**

3.5.2. Time Comparison

Figure 3.29 compares the estimated drilling durations of the reference design and the proposed LWDS design. A great amount of 24 days can be saved. A large part of this savings is open hole time, which very much improves well bore quality and reduces the risk of drilling problems. If the total well construction time including completion and well testing operations is considered, savings of 55% are revealed by applying the LWDS approach.

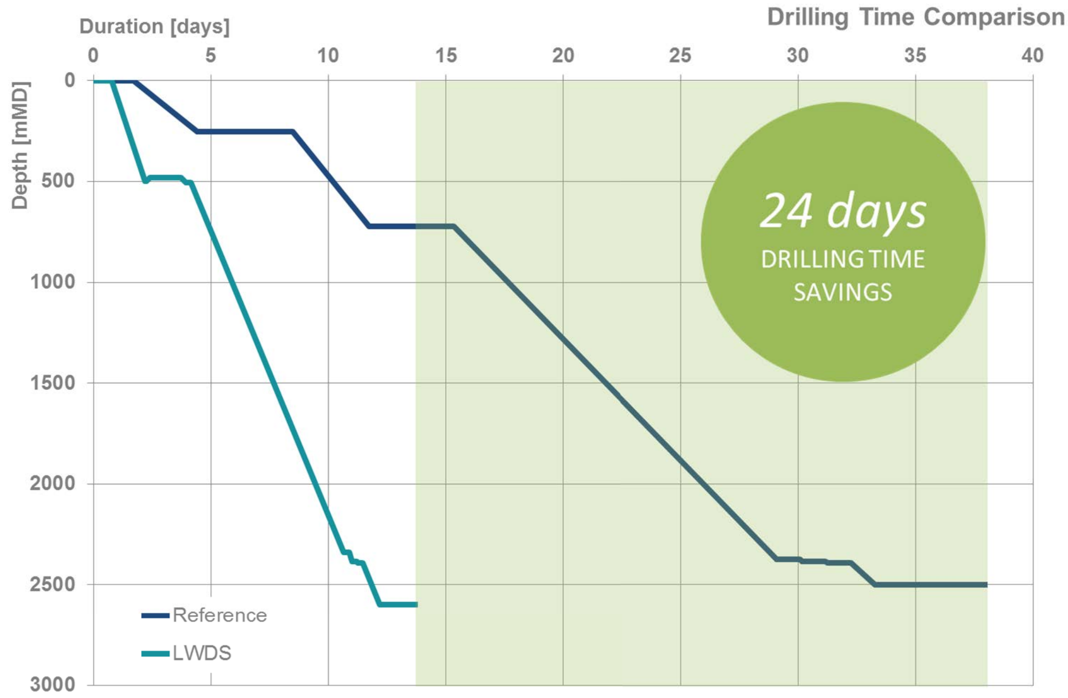

Figure 3.29.: Comparison of reference well drilling duration (dark blue) and the proposed LWDS drilling duration (torquise).

Figure 3.30 compares the absolute and relative amounts of Bit On Bottom Time (BOBT) and Flat Time (FT) distributions of the reference and LWDS well. Although the absolute well duration is greatly reduced, the relative time distribution according this categories does not change significantly and is equally distributed. BOBT refers here to the time the bit is in contact with the formation and FT refers to all other time necessary to achieve drilling. The relatively large contributions of BOBT for both well designs are due to the relatively low ROPs that are assumed.

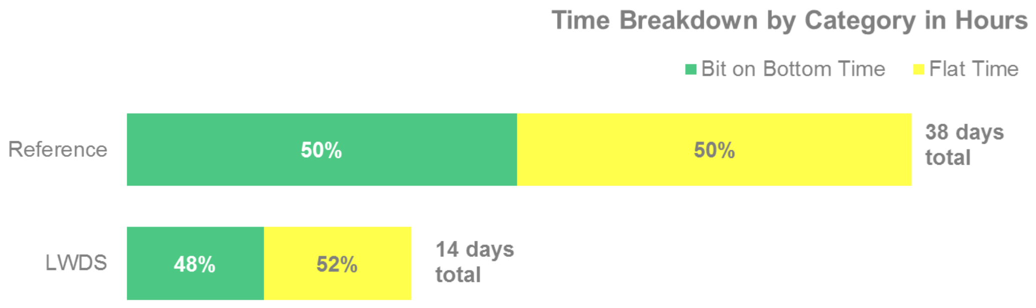

Figure 3.30.: Comparison of BOBT and FT distributions for the reference and LWDS well design. Although the absolute time is greatly reduced with the LWDS design, the relative amounts do not differ significantly and are equally distributed. For both scenarios an average drilling connection of 15 min was assumed.

3.5.3. Cost Comparison

Figure 3.32 illustrates the major cost savings by category. In absolute value the Rig Day Rate cost is reduced most due to the greatly reduced drilling time. Relatively the savings on cementing and commodities due to the reduced hole volume are the greatest. The total well cost of the reference well are estimated by the operator with EUR1.7 million, whereas the LWDS enables to complete the well with a total cost of EUR1.2 million. This is a total cost saving of 30% (Figure 3.31).

Figure 3.31.: Total well cost comparison

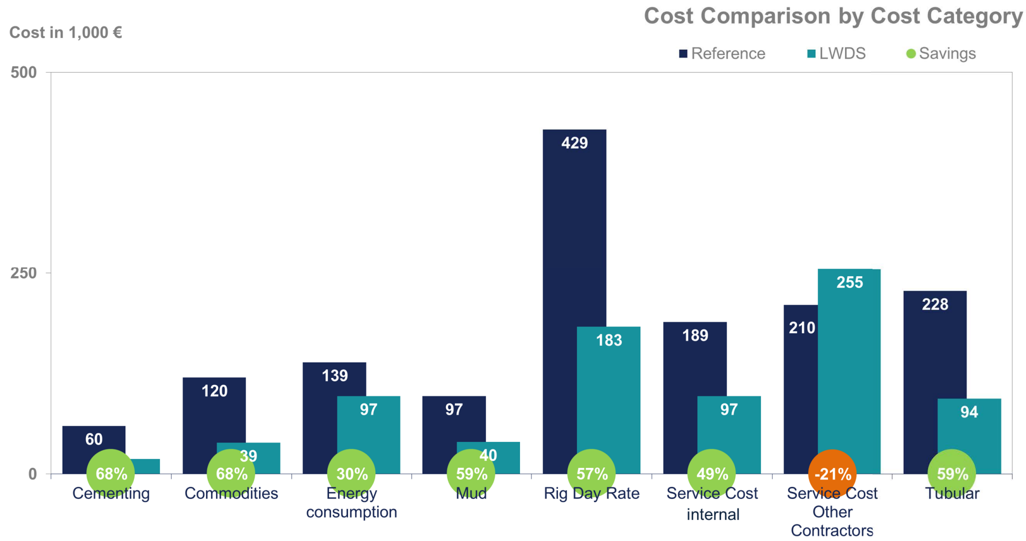

Figure 3.32.: Comparison of reference well costs and LWDS well costs by cost categories.

3.5.4. Sensitivity Analysis

A sensitivity analysis was carried out regarding the factors Drilling Time, 5 inch LWDS Tubular Cost, Mud Cost, LWDS Day Rate, Casing Drive System and MPD and their impact on total cost savings. Figure 3.33 shows the results, with the most sensitive parameter being the drilling time. If the drilling time extends by +110% to 29 days, the well cost for the LWDS proposal equals the reference cost. A two variable sensitivity analysis was carried out subsequently with the Drilling Time parameter and the second most sensitive parameter, MPD Service Cost. Figure 3.34 shows the result of this investigation. The green area indicates savings compared to the reference and the red area indicates when the LWDS becomes more expensive.

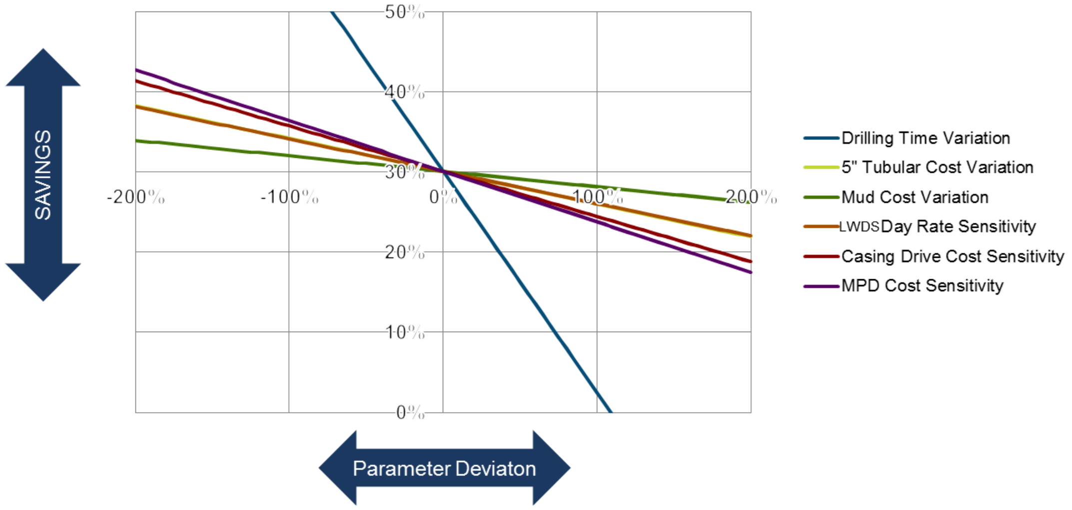

Figure 3.33.: Spider plot of one-variable sensitivity analysis. Drilling Time is the most sensitive parameter.

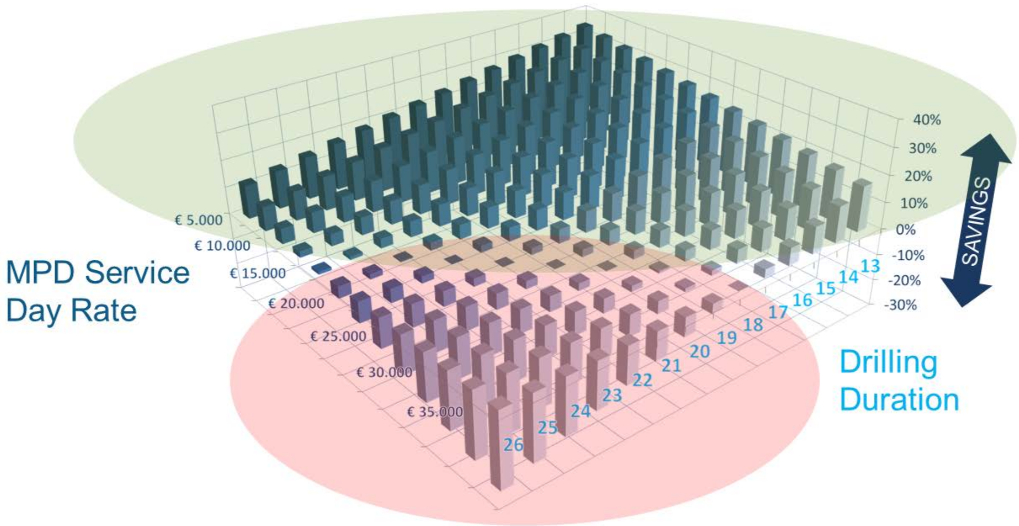

Figure 3.34.: 3D column plot of two-variable sensitivity analysis. Green indicated area is where savings are achieved and the red area indicates where the LWDS becomes more expensive than the reference. Drilling duration is given in days.

3.6. Learning Curve Payout Analysis

In this section the established benchmark for the LWDS well compared to a conventional reference well is extrapolated on a hypothetical well campaign of ten wells. As K. K. Millheim, Prohaska, and Thompson, 1995 state, a major benchmarking tool for slimhole and therefore also for LWDS technology success is the Learning Curve Payout (LCP). According to Brett and K. K. Millheim, 1986 the Learning Curve of a drilling organisation is defined by Equation 3.1 as

$$t = C_1 \times e^{C_2 * (1-n)} + C_3 \tag{3.1}$$

where t is the drilling time to drill the n^{th} well,
n is the number of wells in the field or area of uniform geology,
C_1 is a constant, reflecting how much longer the initial well takes to drill than the final well,
C_2 is a constant, reflecting the speed with which the drilling organisation reaches the drilling time for an area,
C_3 is a constant that reflects the ideal minimum drilling time for an area.

If a well campaign with a number of wells is considered and the total drilling time for conventional and LWDS drilled wells evolves according to Equation 3.1 the LCP is defined as the cumulatively saved total cost in percent. For this study the reference well learning curve was modelled according to average parameters defined by Brett and K. K. Millheim, 1986. The first reference well was assumed to be drilled within the estimated reference time of 39 drilling days. For the LWDS learning curve a variation of parameters was executed and six scenarios were defined. Table 3.15 gives the simulation parameters for the first simulation scenario. Table 3.16 gives a summary of the results for the six LCP simulations, with the values of the varied parameters and a short scenario description. The total well cost was split into fixed cost and daily spread cost. They are also given in Table 3.15. The daily spread cost is multiplied with the total drilling times to give the total well cost for each scenario. Figure 3.35 visualises the LCP simulation results with a bubble chart.

Scenarios one to three are calculated with a conservative minimum drilling time (C_3) of ten drilling days and the rate of learning (C_2) is varied according to Brett and K. K. Millheim, 1986 to represent slow, moderate and fast learning performance. Figures C.1 to C.3 show the results for these scenarios. Scenarios four to six are calculated with a more optimistic minimum drilling time (C_3) of seven days and the same variation for C_2. C_1 is calculated for all cases with a constant $\alpha = \frac{C_1+C_3}{C_3}$ of 210%.

Conclusion

Similar to Brett and K. K. Millheim, 1986 this simulation concludes that fast learning and the push of the technical limit achieve great savings. The LWDS offers a unique way to improve the learning performance (C_2) by enabling continuous coring. With long core sections drilled in the wild cat and exploration wells the drilling organisation learns more than without, which allows the later development wells to be drilled faster. This raises the C_2 factor and improves the Learning Curve Payout substantially. The ideal minimum drilling time (C_3) is by the nature of the LWDS concept significantly lower than for conventional drilling.

Table 3.15.: Summary of learning curve simulation parameters

Learning Curve Payout Simulation Parameters			
Parameter		Reference	LWDS
Ratio of initial to ideal drilling time	C1/C3 + 1	210%	210%
Initial overhead drilling time	C1	20.4	11.0
Rate of learning	C2	0.34	0.25
Ideal minimum drilling time	C3	18.5	10
Fixed Cost per Well		€ 1,150,000.00	€ 700,000.00
Daily Spread Cost		€ 15,000.00	€ 39,000.00

Table 3.16.: Summary of learning curve simulation results

Summary of Learning Curve Simulations					
No.	Scenario	C1	C2	C3	LCP
1	Medium Tech. Limit / Slow Learning	11.00	0.25	10.00	17%
2	Medium Tech. Limit / Moderate Learning	11.00	0.75	10.00	23%
3	Medium Tech. Limit / Fast Learning	11.00	1.25	10.00	25%
4	Aggressive Tech. Limit / Slow Learning	7.70	0.25	7.00	28%
5	Aggressive Tech. Limit / Moderate Learning	7.70	0.75	7.00	33%
6	Aggressive Tech. Limit / Fast Learning	7.70	1.25	7.00	34%

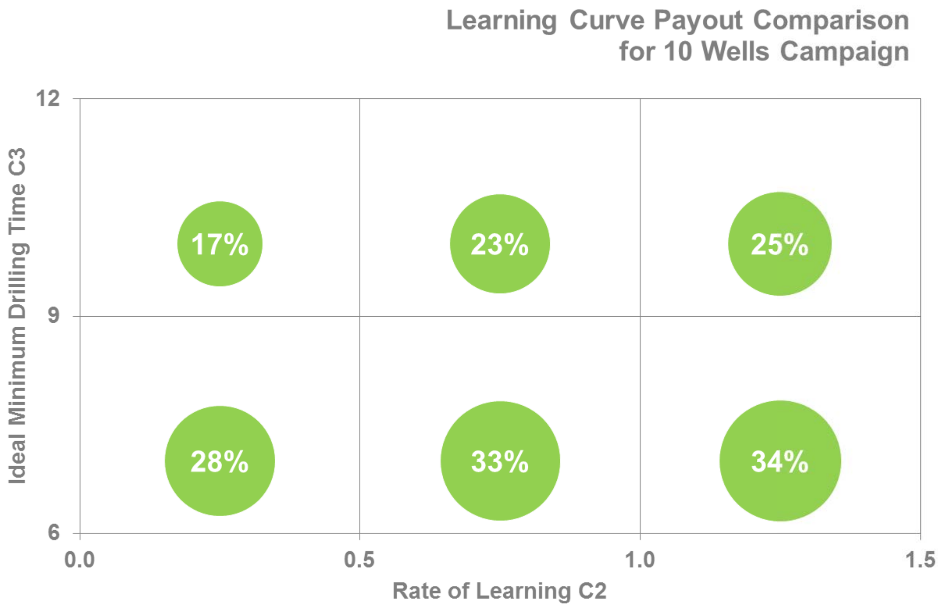

Figure 3.35.: Results of LCP simulations. Axes correspond to the varied constants C_2 and C_3. Each bubble represent a scenario, with its center at the certain variable values and the size of the bubble indicating the amount of savings potential or the LCP. The C_2 axis is split into three ranges, indicating the three levels of learning performance according to Brett and K. K. Millheim, 1986.

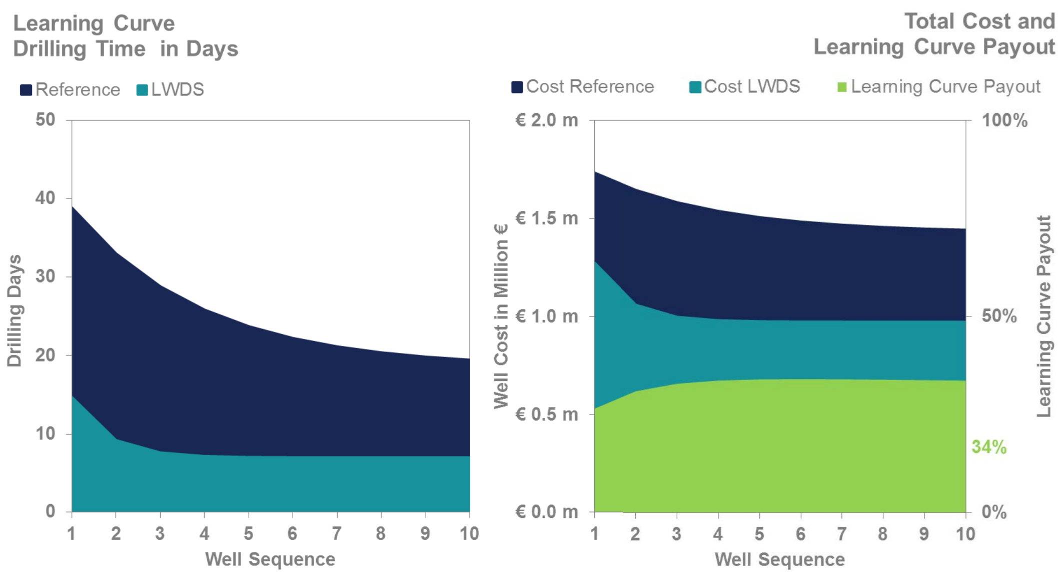

Figure 3.36.: Results of Scenario 6 LCP simulation.

4. Risks and Challenges for Technology Adoption

As the reader worked through the greatest part of this thesis the following question may arise:
"Slimhole technology is the basis of this system and under development for more than thirty years. Why did it never took really off?"
This chapter intends to answer this question by looking into the development of the oil and gas industry with its general approach on how to construct a well. The challenges for technology adoption of the LWDS are very similar to that of the slimhole system and therefore are discussed from a commercial, a technical and an overall system thinking point of view on the basis of slimhole technology.

Commercial Point of View

The historical achievements of the slimhole pioneers show great monetary savings that no other technology in the oil and gas industry was able to achieve so far and the feasibility study under Section 3 shows that these numbers are still valid in today's environment. So why these numbers were not enough to drive the slimhole technology from the eighties to a widely accepted method of drilling wells?

If the oil and gas industries' performance is defined as the ratio of invested CAPEX to the produced hydrocarbon volume, then the main factor why this industry lacks in significant performance improvement is its procurement-driven commercial model introduced in the late nineties. Kibsgaard, 2016 describe how operators elaborate the technical scope of a well project, then the procurement scope is defined and split up into pieces, that are subcontracted to various suppliers. It is this model, that led to many specialised service providers with great expertise, but only in a comparatively small sector of the industry. Even in large service companies isolated and competing subdivisions evolved. Although these specialised service providers managed to improve significantly in its own realms, the overall impact on well cost and efficiency remained comparatively low. This is due to the fact that these companies do not consider or have no access to data from the other industry sectors and no integration of the certain technologies can take place.

As this thesis shows, the concept of a Lightweight Drilling System comprises the complete well construction process and therefore is able to achieve the needed significant savings on the total well construction time and cost. Only an integrated system can provide a step-change in the well construction process and improve the overall process performance. But therefore the business model for such an integrated system needs to be reconsidered. Today's common model in the western hemisphere, where subcontracts are tendered to various service companies consists of quantity based invoicing of commodities and time based invoicing of services with low correlation to the quality of the outcome. Although penalties or reduced rates are given, when operations fail, rewards in case of successful operations in general are not given. In times of decent oil prices the reward is represented by the loyalty of the operator to the service company delivering high quality products, securing it a steady contract backlog and thus a well plan-able cash flow. But in a low oil price environment this "loyalty" of the operator is not a given any more and all services are tendered, giving the lowest price service provider the greatest advantage. Both factors limit the incentives for the service companies to invest in technologies, that aim to improve the overall system's efficiency. And even the industries' large service providers, potentially capable of introducing such technologies have low incentive to do so. As it is shown, major savings are achieved by reducing volumes and quantities of commodities and improving well delivery duration, counteracting their main sources of income. An integrated system needs a major change in the invoicing method and may base its business model partly on the success and quality of its delivered outcome.

Techical Point of View

K. K. Millheim, Prohaska, and Thompson, 1995 state what was the common perception among the industry in the late eighties: safety issues and technological difficulties. In the same paper he concludes that "the technical safety risks are no more severe than with conventional drilling" and that the actual major problem resides "in the integration of all aspects of the slimhole system". This is one of the main lessons from the slimhole campaigns of the eighties and nineties and the LWDS tries to overcome this issue. Therefore Table 4.1 shows a risk estimation by K. K. Millheim, Prohaska, and Thompson, 1995, extended by today's risk estimate for the LWDS technology. Figure 4.1 illustrates the total Risk Score with a spider plot. The blue area indicates the possible risk states and shows that the LWDS is estimated to have equal or even lower total technological risk than conventional drilling. Nevertheless,

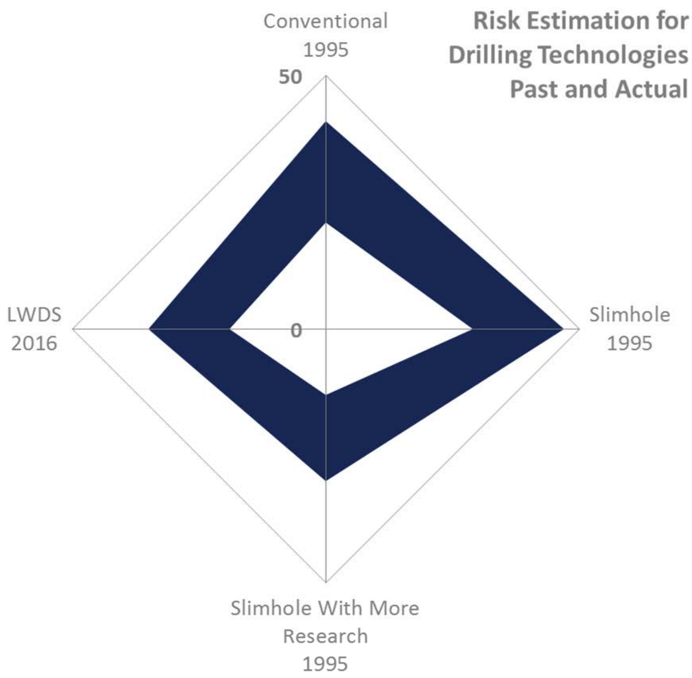

Figure 4.1.: Illustration of Total Risk Score according to Table 4.1. Blue area shows the possible risk states between the minimum and maximum Total Risk Score. It is illustrated, that there is no case, where the risk is higher than for conventional drilling.

the subsystems with higher risk values need more research, this is especially Cementing, Directional Drilling, Completion Process, Fishing Operations and Drill Rig Design.

Systems Thinking Point of View

Again K. K. Millheim, Prohaska, and Thompson, 1995 present a unique way of looking at this technology. They apply a Systems Thinking tool to show some of the main variables affecting the market penetration of slimhole techology. Figure 4.2 shows a Causal Loop Diagram of their Slimhole Usage System, being also valid for the LWDS concept today. The left hand reinforcing loop (R) describes the causalities leading to an increased slimhole technology usage. The driving factor is the cost benefit, which increases the technology proponents, which in turn drive the vendors to offer more equipment and processes for slimhoole operations. The right hand balancing loop (B) describes the causalities preventing the techology from penetrating the market. Here the main driver is lack of information and experience in

Table 4.1.: Risk factor comparison. Table taken from K. K. Millheim, Prohaska, and Thompson, 1995 and extended by the Total Risk Score row and the LWDS column. The LWDS vlaues are the authors estimates for today's technology capacity. It shows the improved state of risk, but also the areas of further research. Risk Factor is based on conventional drilling practices, where 1 ranks lowest and 5 highest. The Total Risk Score is calculated as sum of the individual scores.

Risk Factor Possibility										
Subsystem	**Conventional 1995**		**Slimhole 1995**		**With More Research 1995**		**LWDS 2016**	
	min	**max**	**min**	**max**	**min**	**max**	**min**	**max**
Drill Rig Design	1	1	2	3	1	2	2	3
Well Control	2	4	2	3	1	2	1	2
Logging	1	2	2	3	1	2	2	3
Cementing	2	4	3	4	2	4	2	3
Solids Control	1	3	1	2	0	0	0	0
Drilling Fluids	2	4	3	4	2	4	1	2
Drill Pipe	1	1	3	4	1	2	1	2
Mud Motors	1	2	1	2	0	0	1	2
Directional Drilling	1	2	1	2	0	0	2	3
Lost Circulation	1	3	2	4	1	3	1	3
Well Testing	2	5	2	4	1	3	1	3
Wellbore Stability	2	4	2	4	1	3	1	3
Completion Process	1	1	3	4	1	2	2	3
Fishing Operation	3	5	2	4	1	3	2	3
Total Risk Score	**21**	**41**	**29**	**47**	**13**	**30**	**19**	**35**

slimhole operations that drive the operators perception that these operations are more risky. If the management now in general has a lower risk taking level it will promote preferably conventional drilling. A companies' risk taking level is in general influenced by many factors and a variable inherited from a much greater system as K. K. Millheim, Prohaska, and Thompson, 1995 state. Additionally to this a subloop exists (top right), that shows how contractor lobby promotes conventional drilling and especially prevents the multiplication of available slimhole equipment. The main factors additionally supporting the reinforcing loop and promoting slimhole usage are to be found on the bottom part of the chart. The environmental pressure level and pressure on operators to reduce overall cost are today more valid than ever and present the greatest opportunity and driver for the LWDS technology.

In the end of their paper K. K. Millheim, Prohaska, and Thompson, 1995 state five main factors that can inhibit the usage of slimhole technology. These are:

1. Higher oil and gas prices.
2. Relaxation of environmental pressures.
3. Safety regulations, that favour conventional drilling systems
4. Lack of people trained in slimhole systems technology and operations.
5. Lack of slimhole equipment and products.

In hindsight it is evident that at least three out of these five factors applied (1, 4, and 5) giving, in combination with the presented causality system (Figure 4.2), another answer to the question stated in the very beginning of this chapter.

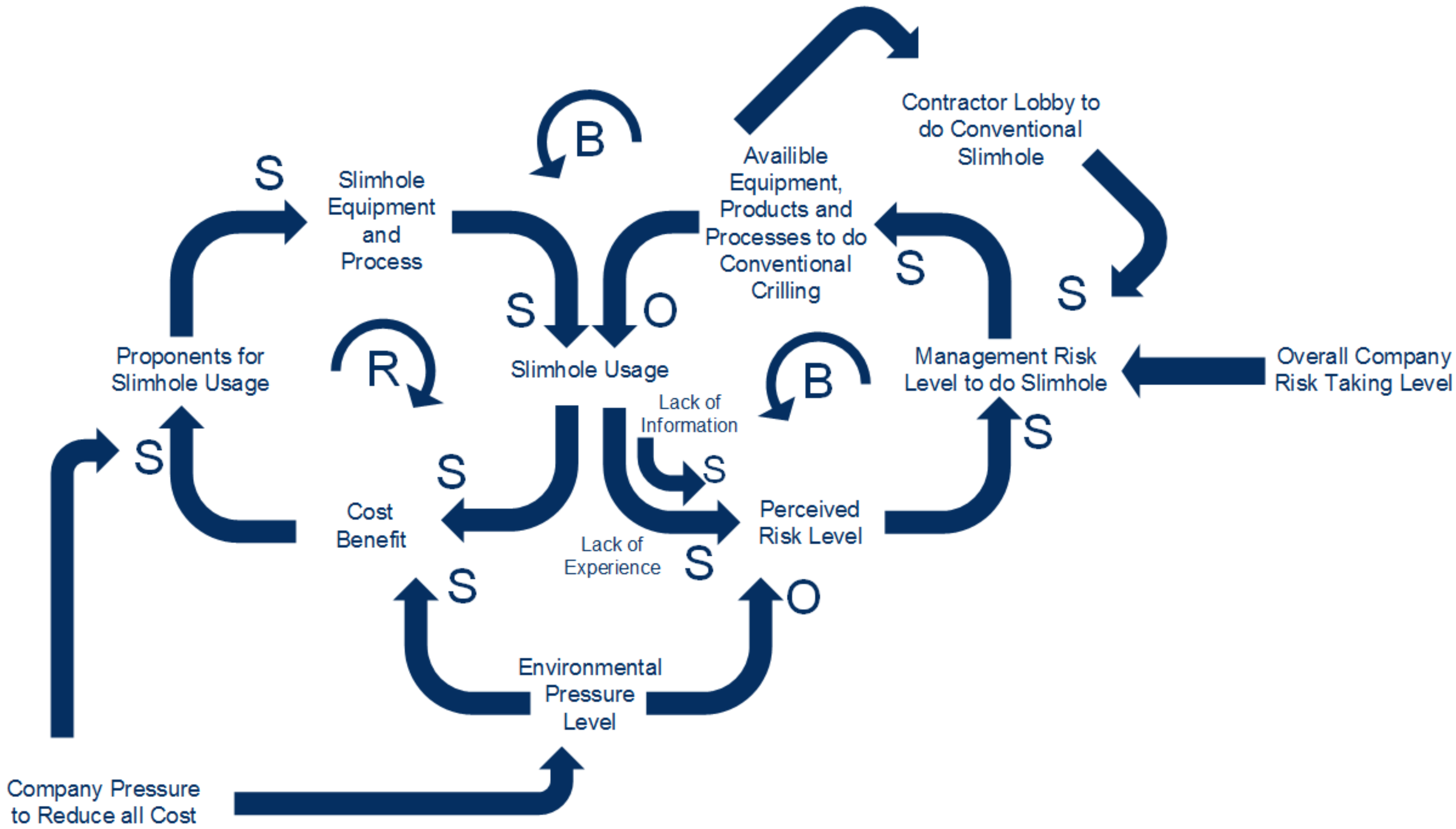

Figure 4.2.: Causal Loop Diagram of Slimhole Usage System re-illustrated according to K. K. Millheim, Prohaska, and Thompson, 1995. The reinforcing loop (R) leads to increased technology usage and the balancing loop (B) acts against. Variables with an "S" act supporting on the causality and ones with an "O" act opposing to it.

5. A Cautious Outlook

According to Cook, 2014 more than 670,000 wells need to go on stream additionally by 2020 in order to compensate for the world's primary energy demand from oil and especially gas. Although this report is from 2014 where more than 3,500 rigs were active worldwide, compared to the in average 1,560 in 2016 (according to Baker Hughes International Rig Count, Baker Hughes, 2016) the number still applies. Actually it may even be higher as major oil companies cut down upstream investments significantly during 2015 and 2016, whereas the energy demand scenarios did not change significantly (according to BP Statistical Review, BP, 2016). K. K. Millheim, Prohaska, and Thompson, 1995 state that: "most of today's drilling (70%-80% of all wells drilled) could be done with some type of slimhole system." As no significant events that could change these shares have occurred within the industry since then, it is considered that these numbers are still valid, resulting in approximately half a million of wells feasible to be drilled with the LWDS until 2020. This represents a market of more than USD 1.5 Billion if an average well cost of three million USD is assumed.

Possible Applications

Possible applications for the LWDS are diverse and some are listed below:

- oil and gas exploration and wild cat wells
- oil and gas development wells
- oil and gas reentry projects
- oil and gas injection wells
- deep geothermal wells
- scientific and stratigraphic sequencing wells
- deep water wells

In general it is also valuable to define the criteria, where a LWDS is not feasible, which inlcude:

- oil and gas high volume producing wells, and
- oil and gas wells were large diameter completions are requested.

Technology Transition

Neal et al., 2007 investigated in their report issued by the U.S. National Petroleum Council technology development and deployment within the oil and gas industry. They state an average duration of 16 years "from concept to widespread commercial adoption", with up to decades more until significant market shares can be gained. Figure 5.1 illustrates average durations for various stages of technology development and deployment. This analysis includes 15 technology cases within the oil and gas upstream sector which in average took 15 years until first field tests were run and another 15 years until 50% market share was gained. In comparison to this it is shown that U.S. Consumer Products take in average only eight years for the same cycle. Furthermore the graphic illustrates how massive funding can shorten this cycle time within the upstream industry, as it was the case with Shell's Expandable Tubular technology.

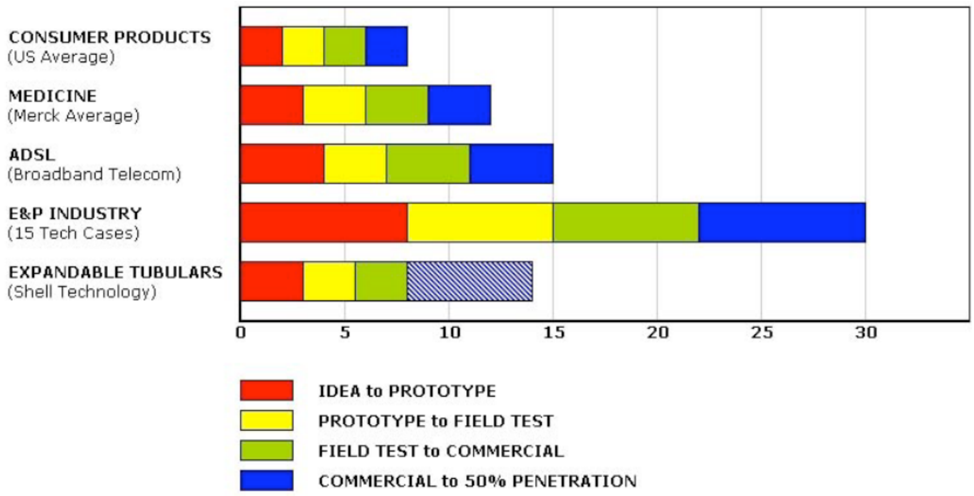

Figure 5.1.: Time to market comparison of oil and gas upstream with other industries. Also included for comparison is Shell's Expandable Tubular technology which was fast-tracked with great funding from the supermajor. Image courtesy of Shell, originally prepared by McKinsey, taken from Neal et al., 2007. Horizontal axis in years.

Technology Maturity

Whereas Figure 5.1 relies on a four level categorisation, Neal et al., 2007 introduce six levels. Today a widespread categorisation system is the Technology Readiness Level (TRL) system based on Sadin, Povinelli, and Rosen, 1989 and used by National Aeronautics and Space Administration (NASA), European Space Agency (ESA) as well as governmental funding regulations like the EU

Horizon 2020 programme. It is a nine tier system and defined as (European Union Commission, n.d.):

Technical Readiness Levels:

- TRL 1: basic principles observed
- TRL 2: technology concept formulated
- TRL 3: experimental proof of concept
- TRL 4: technology validated in lab
- TRL 5: technology validated in relevant environment
- TRL 6: technology demonstrated in relevant environment
- TRL 7: system prototype demonstration in operational environment
- TRL 8: system complete and qualified
- TRL 9: actual system proven in operational environment

With respect to the LWDS, if the slimhole systems from the eighties and nineties are considered, one could argue that the technology and all of its sub-systems were at least at TRL 8 and some sub-systems at TRL 9. Nevertheless, if the low progress in the recent years and the vanishing of key people from operational positions is considered, the overall TRL of slimhole systems as they were back in the nineties has to be decreased today back to TRL 6, waiting for a *new* prototype. Now, if the key difference of the LWDS is the Dual-Body Bit (DBB), and with this sub-technology being at TRL 4 only, the overall TRL of the LWDS is also ranked to TRL 4, waiting for a *new* system prototype and optimisation of the DBB.

Consequently, if the data from Figure 5.1 is taken into account the time-to-market for the LWDS could take from four (Shell case, with fast-tracking by massive funding) to fifteen years (E&P industry average case).

However it is assumed, that with proper project management and commitment from a major client, the time required for designing and manufacturing of an integrated system, capable of drilling a pilot campaign, can be reduced to one year.

6. Conclusion

This thesis introduces the reader to the Light Weight Drilling System (LWDS) concept and shows its potential value. It presents its predecessor, the slimhole technology, that was researched extensively in the eighties and nineties of the last century. This technology proofed that it can achieve total cost savings of up to 50 % and even more compared to conventional drilling. It is shown how the LWDS builds on, and extends this technology and attempts to draw actions from the Lessons Learned in the past in order to conclude in a commercially competitive option for operators.

The sub-technologies of the integrated LWDS are examined one-by-one and references for further study are given.

A feasibility study for a Central East European (CEE) operator is reported in Section 3 with the major finding, that today even, with only a partial implementation of the LWDS, 30% savings on total well cost are feasible. Subsequently the results of a Learning Curve Payout (LCP) simulation are presented, showing that fast learning can increase this potential greatly.

The thesis concludes with a systematic review on risks and challenges for technology adoption and a cautious outlook is given. In the end the author's priorities for further research and actions in order to achieve commercialisation of the LWDS are as follows:

1. Continue research on the Dual-Body Bit (DBB) and Wireline BHA systems.
2. Build a research well analogous to the one presented in Section 2.6.
3. Build a new LWDS rig and integrate downhole and surface systems.
4. Execute a drilling campaign and prove the technology in the field.

With these actions, the proper project management and the commitment of a major end-user it is achievable to launch the technology within one year.

Acronyms

Acronyms

API American Petroleum Institute
BHA Bottom Hole Assembly
BOBT Bit On Bottom Time
BOD Basis of Design
BPC Basal Paleogene Clastics
CAPEX Capital Expenditures
CDS Casing Drive System
CEE Central East European
CwD Casing while Drilling
DBB Dual-Body Bit
DTH Down The Hole
ECD Equivalent Circulating Density
ESA European Space Agency
FAR Flow Area Ratio
FEM Finite Element Method
FT Flat Time
HPL Hydraulic Power Loss
KCl Potassium Chloride
KOP Kick Off Point
LCM Lost Circulation Material
LCP Learning Curve Payout
LOT Leak-Off Test
LWDS Light Weight Drilling System
MPD Managed Pressure Drilling
MSE Mechanical Specific Energy
M/U Make Up
NASA National Aeronautics and Space Administration
PDC Polycristalline Diamond Compact
PDM Positive Displacement Motor
POOH Pull Out Of Hole
RCD Rotating Control Device
RIH Run In Hole
ROB Rotate off Bottom

ROP Rate of Penetration
RSS Rotary Steerable System
SCC Slimhole Continuous Coring
SCD Slimhole Casing Drilling
SHADS Slim-Hole High-Speed Advanced Drilling System
SPL System Pressure Loss
TCI Tungsten Carbide Insert
TD Total Depth
TRL Technology Readiness Level
TVD True Vertical Depth
UH10 Uhřice 10
WOB Weight on Bit
ZA11 ZA11

Bibliography

Baker Hughes (2016). *International Rig Count*. URL: http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-rigcountsintl (cit. on p. 77).

Bencic, A. et al. (1998). "Slimhole Drilling and Coring - A New Approach". In: *SPE Annual Technical Conference and Exhibition*. DOI: 10.2118/49261-MS (cit. on pp. 9, 11, 18).

Bode, D. J., R. B. Noffke, and H. V. Nickens (1991). "Well-Control Methods and Practices in Small-Diameter Wellbores". In: *Journal of Petroleum Technology* 43.11, pp. 1380–1386. ISSN: 0149-2136. DOI: 10.2118/19526-PA (cit. on pp. 4, 5, 15, 24, 26, 49).

BP (2016). *BP Statistical Review of World Energy 2016*. URL: http://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html (cit. on p. 77).

Brett, J. F. and K. K. Millheim (1986). "The Drilling Performance Curve: A Yardstick for Judging Drilling Performance". In: *SPE Annual Technical Conference and Exhibition*. Society of Petroleum Engineers. ISBN: 978-1-55563-607-4. DOI: 10.2118/15362-MS (cit. on pp. 67–69).

Cartalos, Ulysse and Dominique Dupuis (1993). "An Analysis Accounting for the Combined Effect of Drillstring Rotation and Eccentricity on Pressure Losses in Slimhole Drilling". In: *SPE/IADC Drilling Conference*. Society of Petroleum Engineers. ISBN: 978-1-55563-494-0. DOI: 10.2118/25769-MS (cit. on p. 25).

Cook, Matt (2014). "670,000+ wells to be drilled through 2020: Douglas-Westwood forecast: 35% increase in well completion count from 2013-2020 to drive only 17% rise in oil, gas output". In: *Drilling Contractor* 4. URL: http://www.drillingcontractor.org/670000-wells-to-be-drilled-through-2020-28709 (cit. on p. 77).

DeLange, Richard W., Ed Evans, and Richard Griffin (2002). "Casing Drilling Connector With Low Stress Flex Groove". US 6,406,070 B1 (cit. on p. 18).

Dupuis, Dominique (2001). "Slim Hole Saga". In: *SPE/IADC Drilling Conference*. Society of Petroleum Engineers. ISBN: 978-1-55563-933-4. DOI: 10.2118/67732-MS (cit. on pp. vii, 1).

Dupuis, Dominique et al. (1995). "Validation of Kick Control Method and Pressure Loss Predictions on a Slim Hole Well". In: *SPE/IADC Drilling Conference*. Society of Petroleum Engineers. ISBN: 978-1-55563-456-8. DOI: 10.2118/29348-MS (cit. on p. 15).

Endsley, M. R. and D. B. Kaber (1999). "Level of automation effects on performance, situation awareness and workload in a dynamic control task". In: *Ergonomics* 42.3, pp. 462–492. ISSN: 0014-0139. DOI: 10.1080/001401399185595 (cit. on p. 21).

European Union Commission. *Horizon 2020 - Work Programme 2014-2015 General Annex G. Technology readiness levels (TRL)*. URL: http://ec.europa.eu/research/participants/data/ref/h2020/wp/2014_2015/annexes/h2020-wp1415-annex-g-trl_en.pdf (cit. on p. 79).

Golonka, Jan and Frank J. Picha, eds. (2006). *The Carpathians and Their Foreland: Geology and Hydrocarbon Resources*. Vol. 84,CD-ROM. AAPG memoir. Tulsa, Oklahoma, U.S.A: American Association of Petroleum Geologists. ISBN: 0891813659 (cit. on pp. 30, 31).

Groenevelt, P. et al. (1997). "Slim Hole Exploration: One Year Experience in Romania". In: *SPE/IADC Drilling Conference*. Society of Petroleum Engineers. ISBN: 978-1-55563-414-8. DOI: 10.2118/37657-MS (cit. on p. 24).

Karimi, Moji, Timothy Eric Moellendick, and Calvin Holt (2011). "Plastering Effect of Casing Drilling; a Qualitative Analysis of Pipe Size Contribution". In: *SPE Annual Technical Conference and Exhibition*. DOI: 10.2118/147102-MS (cit. on p. 12).

Kibsgaard, Paal (2016). *Kibsgaard Speaks at Morgan Stanley E&P & Oil Services Conference: May 9, 2016 Paal Kibsgaard, Chairman and CEO of Schlumberger N.V.* URL: http://investorcenter.slb.com/phoenix.zhtml?c=97513&p=irol-presentations (cit. on p. 71).

Macpherson, John Duncan et al. (2013). "Drilling Systems Automation: Current State, Initiatives and Potential Impact". In: *Technical papers*. Richardson, TX: Society of Petroleum Engineers. ISBN: 978-1-61399-240-1. DOI: 10.2118/166263-MS (cit. on p. 21).

Millheim, K. K., M. Prohaska, and B. Thompson (1995). "Slim Hole Drilling Technology - Past, Present, Future". In: *PetroVietnam*. Society of Petroleum Engineers. ISBN: 978-1-55563-455-1. DOI: 10.2118/30151-MS (cit. on pp. 67, 72–77).

Neal et al. (2007). *Oil and Gas Technology Development: Topic Paper #26*. National Petroleum Council. URL: www.np.corg (cit. on p. 78).

Ofei, Titus Ntow et al. (2015). "Modified Yield Power-Law fluid flow in narrow annuli with inner rotating pipe". In: *The Canadian Journal of Chemical Engineering* 93.1, pp. 150–165. ISSN: 00084034. DOI: 10.1002/cjce.22100 (cit. on p. 25).

Parasuraman, R., T. B. Sheridan, and C. D. Wickens (2000). "A model for types and levels of human interaction with automation". In: *IEEE Transactions on Systems, Man, and Cybernetics - Part A: Systems and Humans* 30.3, pp. 286–297. ISSN: 1083-4427. DOI: 10.1109/3468.844354 (cit. on p. 21).

Sackmaier, W. et al. (2014). "Use of Drilling With Casing Technology To Provide Operational Efficiency in the Vienna Basin". In: *SPE/EAGE European Unconventional Resources Conference and Exhibition*. [Richardson, Tex.]:

Society of Petroleum Engineers. ISBN: 978-1-61399-294-4. DOI: 10.2118/167745-MS (cit. on p. 12).
Sadin, Stanley R., Frederick P. Povinelli, and Robert Rosen (1989). "THE NASA TECHNOLOGY PUSH TOWARDS FUTURE SPACE MISSION SYSTEMS A2 - NAPOLITANO, L.G". In: *Space and Humanity*. Ed. by L. G. Napolitano. Burlington: Elsevier Science, pp. 73–77. ISBN: 978-0-08-037877-0. DOI: 10.1016/B978-0-08-037877-0.50012-0 (cit. on p. 78).
Sagot, A. and D. Dupuis (1996). "One Year Experience in Slim Hole Drilling". In: *SPE/IADC Drilling Conference*. Society of Petroleum Engineers. ISBN: 978-1-55563-435-3. DOI: 10.2118/35124-MS (cit. on pp. 1, 20, 24).
Sagot, Andre and Dominique Dupuis (1994). "A Fitted for Purpose Slim-Hole Rig". In: *European Petroleum Conference*. Society of Petroleum Engineers. ISBN: 978-1-55563-461-2. DOI: 10.2118/28867-MS (cit. on pp. 19, 20, 23, 24).
Shanks II, F. E. and K. R. Williams (1993). "Slimhole Exploration Requires Proper Technical Preparation". In: *SPE Annual Technical Conference and Exhibition*. Society of Petroleum Engineers. ISBN: 978-1-55563-481-0. DOI: 10.2118/26337-MS (cit. on pp. 24, 25).
Shepard, S. F., R. H. Reiley, and T. M. Warren (2001). "Casing Drilling: An Emerging Technology". In: *SPE/IADC Drilling Conference*. Society of Petroleum Engineers. ISBN: 978-1-55563-933-4. DOI: 10.2118/67731-MS (cit. on p. 12).
Sheridan, Thomas B. and William L. Verplank (1978). *Human and Computer Control of Undersea Teleoperators*. Cambridge MA 02139 (cit. on p. 21).
Sousa, J.T.V. de et al. (1999). "Optimization of Slimhole Dual-Body Bits by Experiments and Computational Fluid Dynamics". In: *SPE Western Regional Meeting*. DOI: 10.2118/54595-MS (cit. on pp. 9, 11).
Spain, David R., Steven A. Morris, and John T. Penn (1992). "Automated Geological Evaluation of Continuous Slim-Hole Cores". In: *Journal of Petroleum Technology* 44.06, pp. 662–668. ISSN: 0149-2136. DOI: 10.2118/23577-PA (cit. on pp. 13, 27, 28).
Vert, Jeffrey Walter and Per G. Angman (2008). "Cementing Float and Method For Drilling And Casing A Wellbore With A Pump Down Cement Float". US 7,428,927 B2 (cit. on pp. 18, 19).
Walker, Scott H. and Keith K. Millheim (1990). "An Innovative Approach to Exploration and Exploitation Drilling: The Slim-Hole High-Speed Drilling System". In: 42.09, pp. 1184–1191. DOI: 10.2118/19525-PA (cit. on pp. 1, 12).

Appendix

Appendix A.

General Appendices

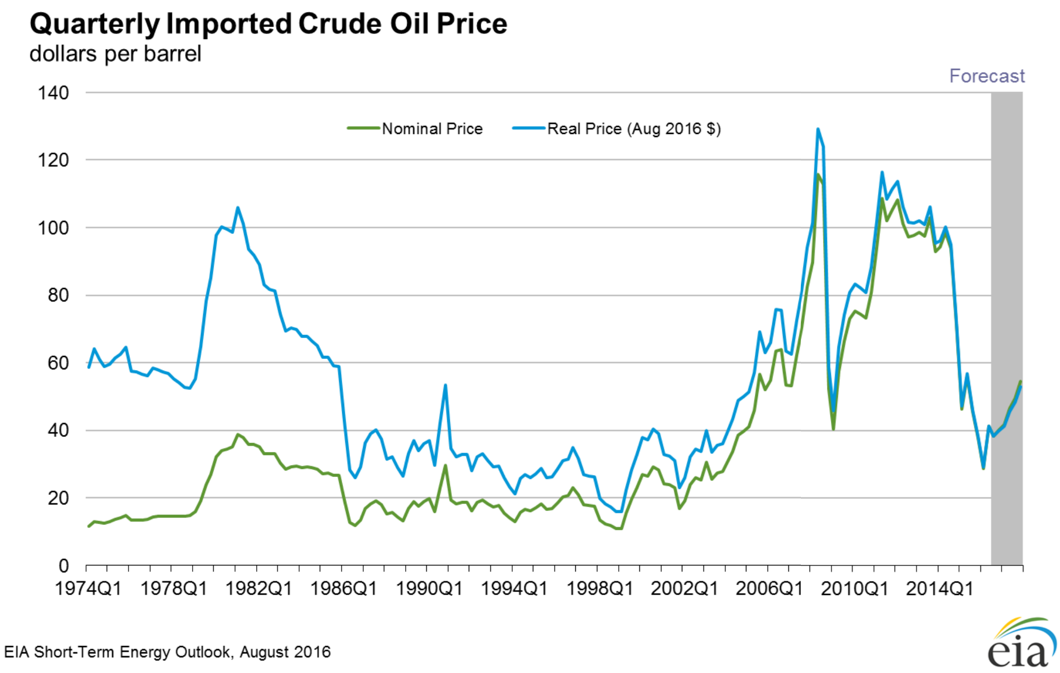

Figure A.1.: Adjusted and nominal oil price 1974 to 2017. Source: U.S. Energy Information Administration (EIA).

Table A.1.: Hydraulic optimisation. Scenario parameters.

Scenarios										
No	Descr.	Hydraulics Model (Inside Pipe / Annulus)	Flow Rate [l/min]	Hole Size [in]	Pipe OD [in]	Pipe ID [in]	Annular Clearance [in]	IPA [in²]	AA [in²]	FAR
1	Conventional	Bingham / Bingham	650	6.000	3.500	2.764	1.250	6.00	18.65	3.11
2	LWDS Case Study	Bingham / Nickens	310	6.000	5.000	4.494	0.500	15.86	8.64	0.54
3	FAR of 0.75	Bingham / Nickens	370	6.000	4.740	4.250	0.630	14.19	10.63	0.75
4	FAR of 1.00	Bingham / Nickens	440	6.000	4.470	4.000	0.765	12.57	12.58	1.00
5	FAR of 1.50	Bingham / Nickens	500	6.000	4.250	3.500	0.875	9.62	14.09	1.46

Table A.2.: Hydraulic optimisation. Scenario calculations

Scenarios											
No	Descr.	Inside pipe velocity [ft/s]	Annular velocity [ft/s]	Bingham Pipe Critical Velocity [ft/s]	Bingham Annulus Critical Velocity [ft/s]	Pipe Flow Regime	Annular Flow Regime	Pipe Pressure Loss Laminar [bar/m]	Pipe Pressure Loss Turbulent [bar/m]	Annular Pressure Loss Laminar [bar/m]	Annular Pressure Loss Turbulent [bar/m]
1	Conventional	9.2	3.0	6.7	6.8	Turbulent	Laminar	0.011	0.021	0.009	0.004
2	LWDS Case Study	1.7	3.0	6.0		Laminar	Turbulent	0.004	0.001		0.016
3	FAR of 0.75	2.2	3.0	6.0		Laminar	Turbulent	0.004	0.001		0.011
4	FAR of 1.00	3.0	3.0	6.1		Laminar	Turbulent	0.005	0.002		0.008
5	FAR of 1.50	4.4	3.0	6.3		Laminar	Turbulent	0.006	0.004		0.009

Appendix B.

Feasibility Study Appendices

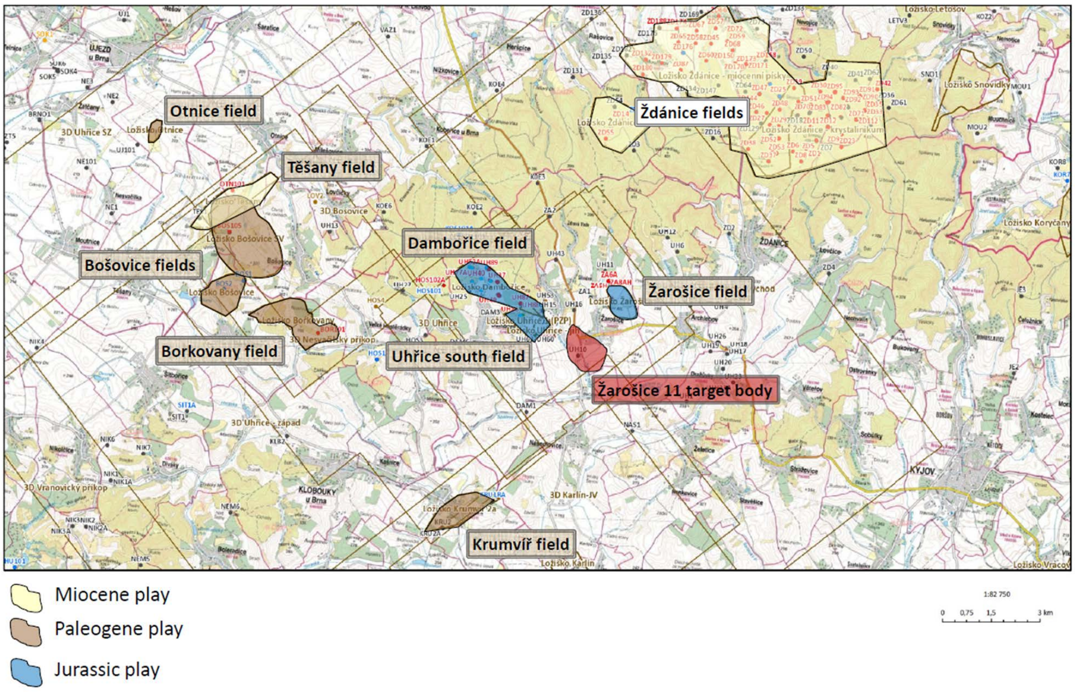

Figure B.1.: Map of south eastern Moravia with oil and gas fields. Indicated in red is the ZA11 Paleogene target body in between two major fields Uhřice and Žarošice .

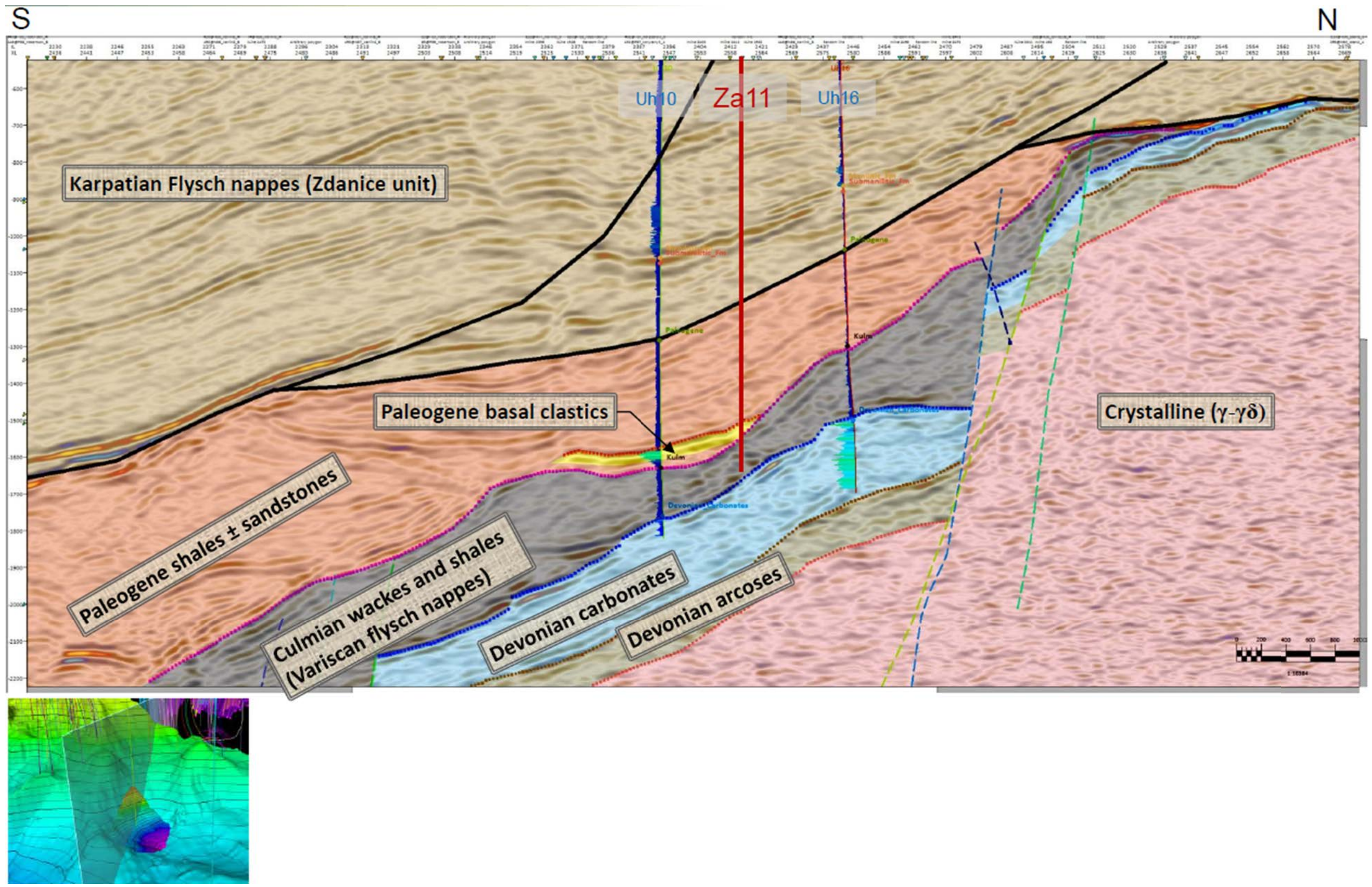

Figure B.2.: Interpreted south-north cross section of the north eastern Nesvačilka structure. Wells UH10 and ZA11 are indicated in blue and red respectively. Note the topologically higher well placement of ZA11 compared to UH10. The small image of the 3D seismic indicates the cross section plane through the reservoir.

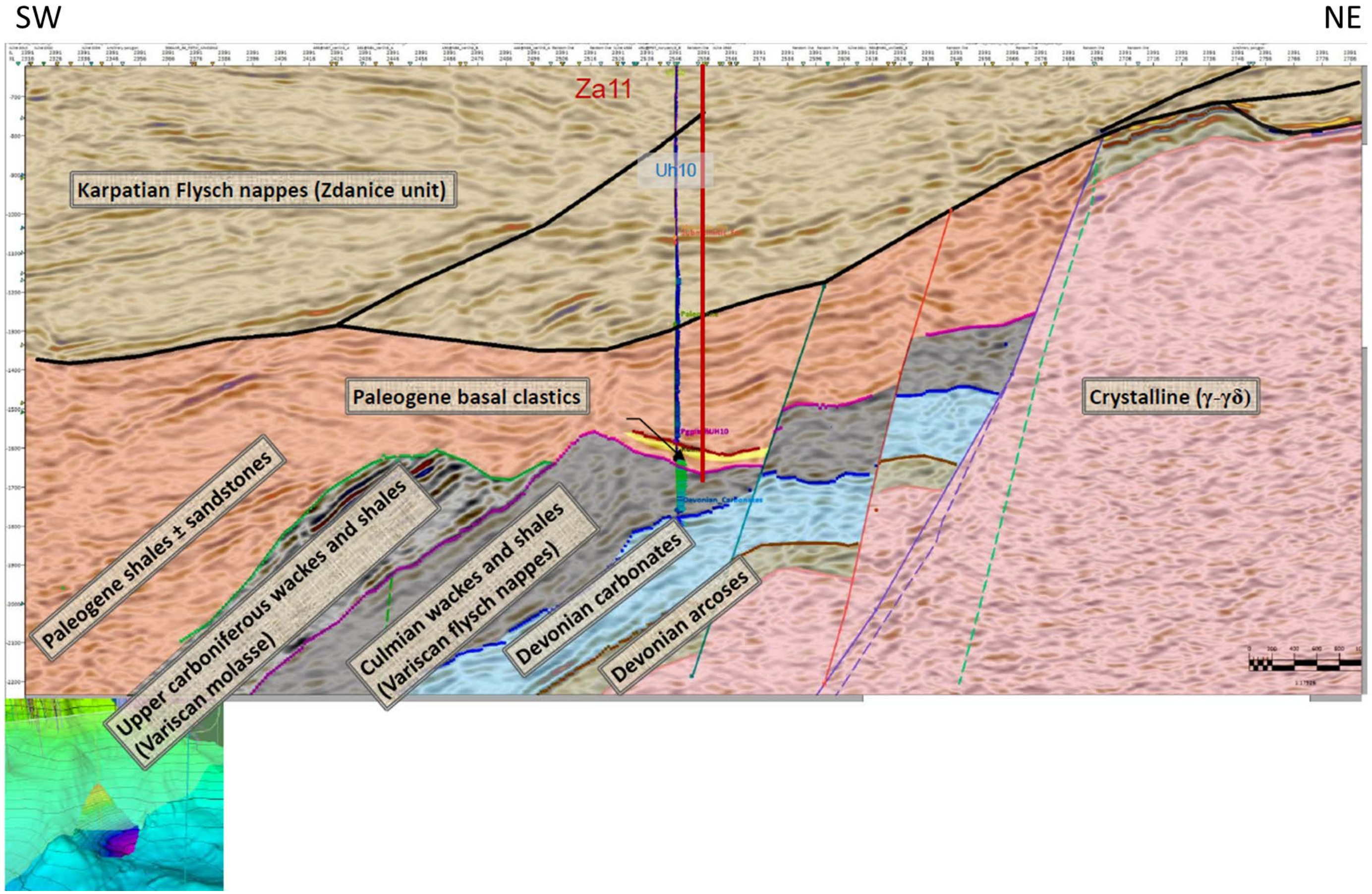

Figure B.3.: Interpreted south west-north east cross section of the north eastern Nesvačilka structure. Wells UH10 and ZA11 are indicated in blue and red respectively. The small image of the 3D seismic indicates the cross section plane through the reservoir.

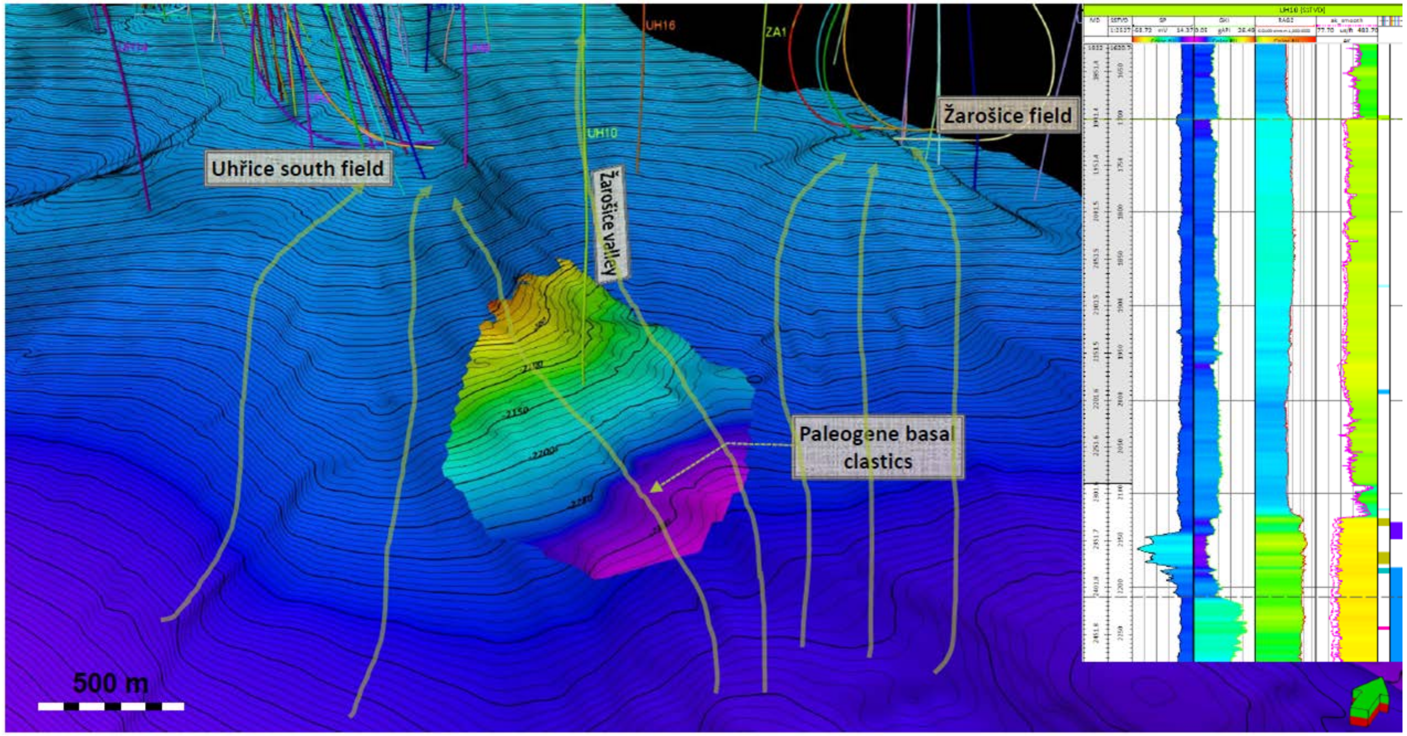

Figure B.4.: 3D image of the target BPC reservoir with the UH10 offset well in the center. Adjacent to the suspected reservoir the readily drilled Uhrice South and Zarosice fields are indicated and furthermore the suspected migration paths from deeper strata are indicated. It is assumed that the hydrocarbons originate from the same source rock as in Uhrice and Zarosice fields

Table B.1.: Comparison of evaluated BODs for the well ZA11.

Casing Design Comparison						
Section	**Section Depth**	**Hole Size**	**Outer Diameter**	**Wall Thickness**	**Weight**	**Type**
Reference Casing Design / Cost €145,000 / Weight 160 t						
Surface	250 mMD	17.500 in	13.375 in	0.380 in	54.50 lb/ft	API J-55 BTC
Intermediate	720 mMD	12.250 in	9.625 in	0.395 in	40.00 lb/ft	API N-80 BTC
Production A	2,100 mMD	8.500 in	7.000 in	0.317 in	23.00 lb/ft	API J-55 BTC
Production B	2,600 mMD	8.500 in	7.000 in	0.317 in	23.00 lb/ft	API N-80 BTC
LWDS BOD #1 / Cost €83,000 / Weight 73 t						
Surface	300 mMD	12.250 in	10.750 in	0.279 in	32.75 lb/ft	API J-55 BTC
Intermediate	800 mMD	9.500 in	7.625 in	0.300 in	24.00 lb/ft	API J-55 BTC
Production	2,100 mMD	6.750 in	5.500 in	0.157 in	12.00 lb/ft	VA SEW 090-2 (S690QL)
Liner fr. 1800mMD	2,600 mMD	5.000 in	4.000 in	0.142 in	9.00 lb/ft	VA SEW 090-2 (S690QL)
LWDS BOD #2 / Cost 61,000 / Weight 45 t						
Surface	300 mMD	8.500 in	7.625 in	0.300 in	24.00 lb/ft	API J-55 BTC
Intermediate	800 mMD	6.750 in	5.500 in	0.157 in	11.00 lb/ft	VA SEW 090-2 (S690QL)
Production	2,600 mMD	5.000 in	4.000 in	0.142 in	9.00 lb/ft	VA SEW 090-2 (S690QL)
LWDS BOD #3 / Cost €149,000 / Weight 125 t						
Surface	300 mMD	17.500 in	13.325 in	0.330 in	48.00 lb/ft	API J-55 BTC
Intermediate	800 mMD	11.750 in	9.625 in	0.333 in	42.00 lb/ft	API J-55 BTC
Production	2,100 mMD	8.250 in	6.625 in	0.288 in	21.00 lb/ft	VAGT SC Grade 80
Liner fr. 1800mMD	2,600 mMD	5.500 in	4.000 in	0.226 in	11.00 lb/ft	VAGT Grade 80
LWDS BOD #4 / Cost €99,0000 / Weight 72 t						
Surface	300 mMD	12.250 in	9.625 in	0.333 in	42.00 lb/ft	API J-55 BTC
Intermediate	800 mMD	8.250 in	6.625 in	0.288 in	21.00 lb/ft	VAGT SC Grade 80
Production	2,600 mMD	5.500 in	4.000 in	0.226 in	11.00 lb/ft	VAGT Grade 80
LWDS BOD #5 / Cost €120,000 / Weight 98 t						
Surface	300 mMD	12.250 in	10.750 in	0.279 in	32.75 lb/ft	API J-55 BTC
Intermediate	800 mMD	9.500 in	7.625 in	0.300 in	24.00 lb/ft	API J-55 BTC
Production	2,100 mMD	6.800 in	5.500 in	0.275 in	15.50 lb/ft	VAGT Grade 80
Liner fr. 1800mMD	2,600 mMD	4.750 in	3.500 in	0.216 in	11.00 lb/ft	VAGT Grade 80
LWDS BOD #6 / Cost €79,000 / Weight 57 t						
Surface	800 mMD	9.125 in	7.625 in	0.300 in	24.00 lb/ft	API J-55 BTC
Intermediate	2,100 mMD	6.900 in	5.500 in	0.275 in	15.50 lb/ft	VAGT Grade 80
Production	2,600 mMD	4.750 in	3.500 in	0.216 in	11.00 lb/ft	VAGT Grade 80
LWDS BOD #7 (FINAL) / Cost € 94,000 / Weight 67 t						
Surface	720 mMD	8.500 in	7.000 in	0.317 in	23.00 lb/ft	VAGT Grade 80
Production	2,600 mMD	6.000 in	5.000 in	0.253 in	13.00 lb/ft	VAGT Grade 80

Table B.2.: Detailed well cost breakdown for LWDS proposal.

Detailed Cost Breakdown LWDS Well Proposal							
No	Cost Group	Cost Position	Unit	Quant.	Currency	Unit cost	Total cost
1	Pre-Spud and Recultivation work	Wellpad construction	#	1.00	[EUR]	80,597	80,597
2	Rig Assembly Work	R/U	#	1.00	[EUR]	48,715	48,715
3	Rig Assembly Work	R/D	#	1.00	[EUR]	19,486	19,486
4	Rig Assembly Work	Rig Transport	#	1.00	[EUR]	21,065	21,065
5	Rig Day Rate	Daily Rate	[day]	18.80	[EUR]	9,743	183,149
6	Energy consumption	Diesel	[litre]	77,000.00	[EUR]	1	97,321
7	Water	Water	[m3]	500.00	[EUR]	1	737
8	Cementing	Slurry for 7" Csg.	[m3]	12.00	[EUR]	173	2,073
9	Cementing	Slurry for 5" Csg.	[m3]	25.00	[EUR]	173	4,318
10	Cementing	CemNet	[m3]	10.00	[EUR]	695	6,952
11	Cementing	Wash	[m3]	5.00	[EUR]	21	105
12	Cementing	Spacer MP II	[m3]	5.00	[EUR]	1,116	5,582
13	Tubular	Csg. TDE 7", g80	[t]	17.00	[EUR]	1,400	23,800
14	Tubular	Csg. TDE 5", g80	[t]	50.00	[EUR]	1,400	70,000
15	Commodities	X-mas tree	#	1.00	[EUR]	29,491	29,491
16	Commodities	Fence	#	1.00	[EUR]	2,317	2,317
17	Completion	Tbg. 2 7/8", EU, J-55	[m]	2,000.00	[EUR]	16	32,019
18	Completion	Completion	#	1.00	[EUR]	10,533	10,533
19	Service Cost Other Contractors	Slick Line service	[job]	1.00	[EUR]	4,634	4,634
20	Service Cost Other Contractors	Perforation	[job]	1.00	[EUR]	23,593	23,593
21	Service Cost Internal	Pressure gauges	[job]	1.00	[EUR]	421	421
48	Service Cost Other Contractors	DST	[job]	1.00	[EUR]	12,090	12,090
22	Mud	Mud Chemicals	[job]	1.00	[EUR]	33,000	33,000
23	Service Cost Internal	Logging CH	#	1.00	[EUR]	9,690	9,690
24	Service Cost Internal	Cementation service	[job]	1.00	[EUR]	14,746	14,746
25	Service Cost Internal	BOP service	[job]	1.00	[EUR]	2,528	2,528
26	Service Cost Internal	Transportation	[job]	1.00	[EUR]	42,130	42,130
27	Service Cost Other Contractors	Cuttings disposal	[job]	1.00	[EUR]	23,172	23,172
28	Service Cost Other Contractors	MWD / LWD	[day]	5.00	[EUR]	10,533	52,663
29	Service Cost Other Contractors	SLB cementing supervisor	[day]	2.00	[EUR]	1,000	2,000
30	Service Cost Other Contractors	MWD insurance	[job]	1.00	[EUR]	21,065	21,065
31	Mud	Mud Engineer Service	[day]	13.80	[EUR]	500	6,899
32	Commodities	Wellhead 7"	#	1.00	[EUR]	5,000	5,000
33	Service Cost Internal	Wireline Winch for BHA handling	[day]	13.80	[EUR]	2,000	27,596
34	Commodities	Float Collar 7"	#	1.00	[EUR]	1,000	1,000
35	Commodities	Float Collar 5"	#	1.00	[EUR]	1,000	1,000
36	Commodities	Casing Drilling Compund	#	1.00	[EUR]	500	500
37	Service Cost Other Contractors	TDE Supervisor, LWDS BHA Tools, 18 [m] LWDS Coring	[day]	13.80	[EUR]	5,000	68,990
38	Drilling Tools Rental Costs	Casing Drive System	[day]	13.80	[EUR]	3,000	41,394
39	Drilling Tools Rental Costs	Casing Tongs and Elevator	[day]	13.80	[EUR]	600	8,279
40	Service Cost Other Contractors	CDS Operators	[day]	13.80	[EUR]	1,750	24,146
41	Service Cost Other Contractors	Tong Operators	[day]	13.80	[EUR]	1,650	22,767
42	Service Cost Other Contractors	MPD Service for 6" section	[day]	10.80	[EUR]	10,000	107,979
	TOTALS				**[EUR]**		**1,195,542**

Table B.3.: Detailed mud statement for LWDS proposal.

Mud Statement

Section	Hole Size [in]	Depth [mMD]	Volume [m³]	MW [kg/m³]	plast. Visc. [cP]	Gel strength 10sec [lbs/100ft²]	Gel strength 10min [lbs/100ft²]	Yield Point [lbs/100ft²]	Filtration [ml/30min]	average pH	av. CEC [kg/m]	av. K+ [mg/l]	av. Cl- [mg/l]	Sand [%]
Surface	8.50	720.00	26.36	1,198	20.00	22.00	43.00	40.00	9.00	10.15	51.10	15,875	9,265	1.50
Production	6.00	2,630.00	47.98	1,078	16.00	5.00	14.00	20.00	5.70	11.15	39.90	30,250	0	0.30

Section	Chemical	Unit	Quant.	Currency	Unit cost	Total cost
Surface	CaCO3	[kg]	1,057	[EUR]	0.03	32.14
Surface	Bentonit OCMA	[kg]	1,215	[EUR]	0.26	311.69
Surface	KMC TS 20	[kg]	264	[EUR]	1.67	441.39
Surface	KCl	[kg]	1,057	[EUR]	0.80	846.00
Surface	KOH	[kg]	0	[EUR]	1.56	0.00
Surface	NaOH	[kg]	40	[EUR]	0.58	23.09
Surface	Potash	[kg]	528	[EUR]	1.37	725.98
Surface	Polypac UL	[kg]	0	[EUR]	3.94	0.00
Surface	Modipol LV	[kg]	343	[EUR]	1.71	588.91
Surface	Modicide	[kg]	137	[EUR]	2.87	394.62
Surface	Soda Bic.	[kg]	0	[EUR]	0.26	0.00
Surface	Citric Acid	[kg]	132	[EUR]	1.11	146.65
Surface	Modivis	[kg]	26	[EUR]	9.07	239.77
Surface	Glydril MC	[kg]	0	[EUR]	2.42	0.00
Surface	Defoamer T	[kg]	34	[EUR]	6.77	232.42
Surface Total		**[kg]**	**4,835**			**3,982.65**
Production	CaCO3	[kg]	13,089	[EUR]	0.03	398.01
Production	Bentonit OCMA	[kg]	0	[EUR]	0.26	0.00
Production	KMC TS 20	[kg]	144	[EUR]	1.67	240.29
Production	KCl	[kg]	0	[EUR]	0.80	0.00
Production	KOH	[kg]	72	[EUR]	1.56	111.98
Production	NaOH	[kg]	0	[EUR]	0.58	0.00
Production	Potash	[kg]	11,507	[EUR]	1.37	15,808.60
Production	Polypac UL	[kg]	0	[EUR]	3.94	0.00
Production	Modipol LV	[kg]	2,517	[EUR]	1.71	4,315.75
Production	Modicide	[kg]	432	[EUR]	2.87	1,239.39
Production	Soda Bic.	[kg]	288	[EUR]	0.26	73.77
Production	Citric Acid	[kg]	360	[EUR]	1.11	399.17
Production	Modivis	[kg]	503	[EUR]	9.07	4,568.42
Production	Glydril MC	[kg]	7,911	[EUR]	2.42	19,128.41
Production	Defoamer T	[kg]	86	[EUR]	6.77	583.97
Production Total		**[kg]**	**36,909**			**46,867.76**
Grand Total		**[kg]**	**41,744**			**50,850.41**

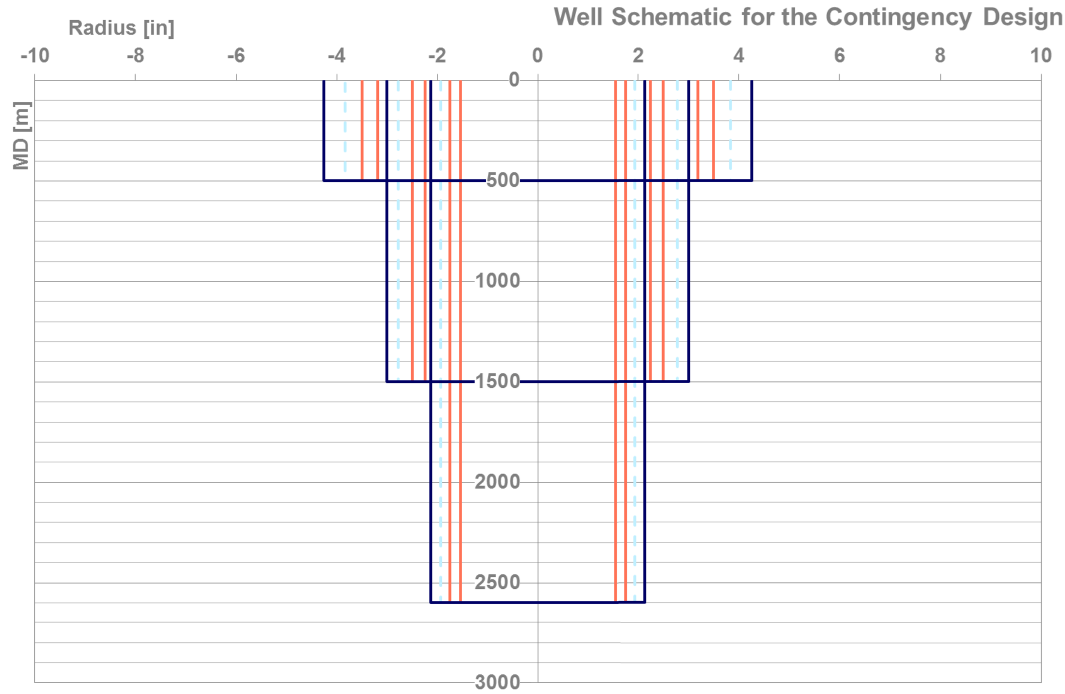

Figure B.5.: Well schematic for the contingency well design

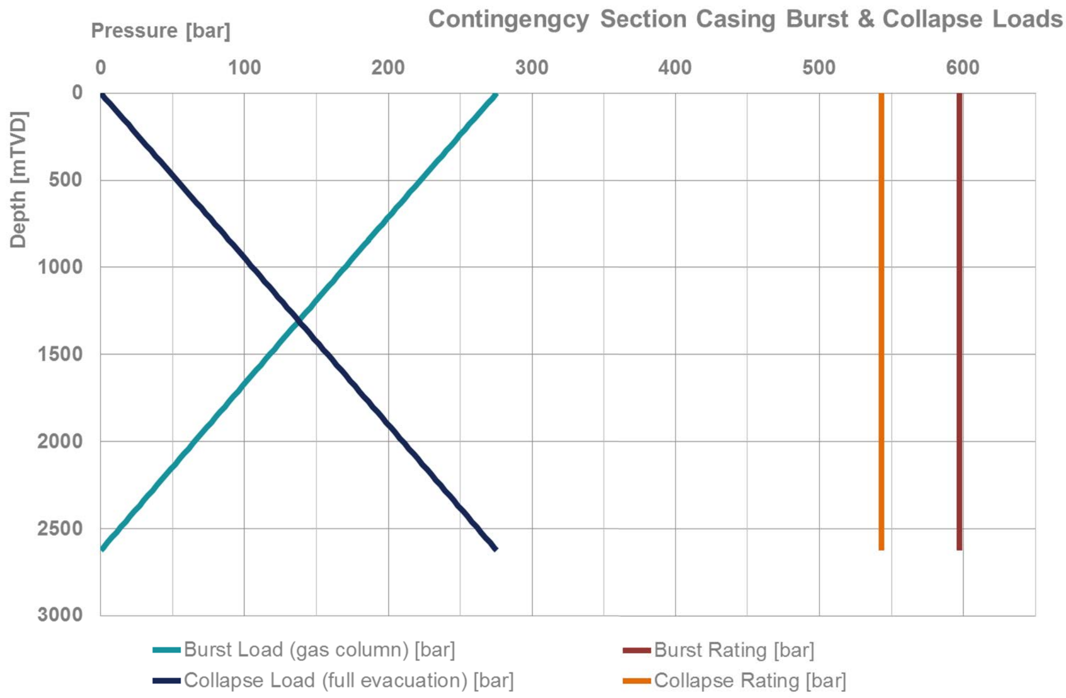

Figure B.6.: Burst and collapse load profiles of contingency section casing. Minimum safety factors are 2.2 for burst and 1.9 for collapse.

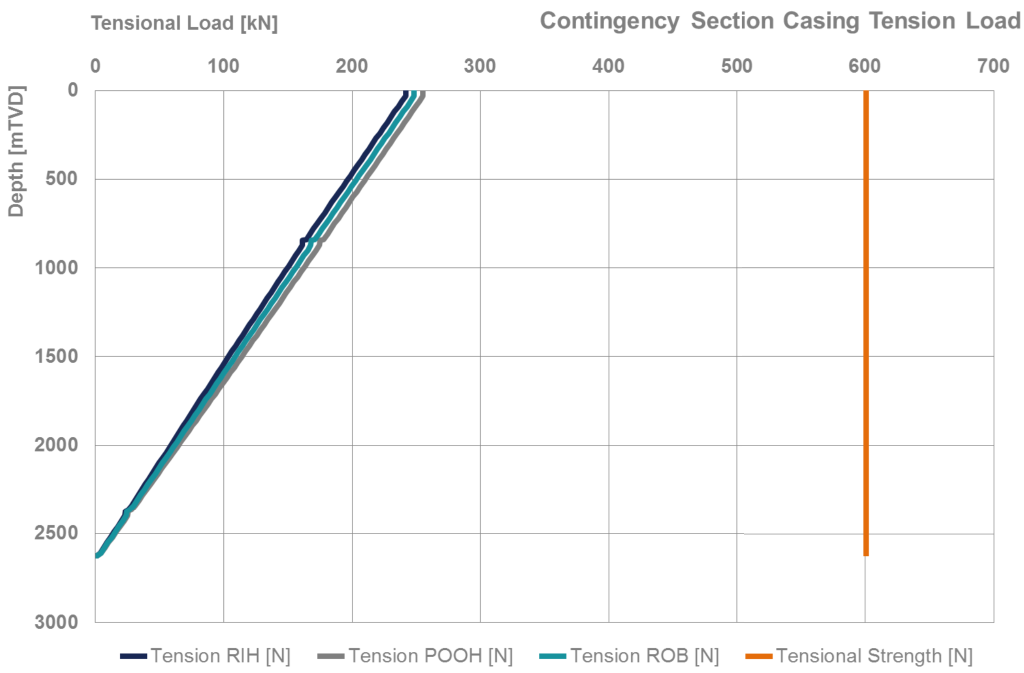

Figure B.7.: Tension load profile of contingency section casing. Minimum safety factor is 2.4 for tension.

Appendix C.

Learning Curve Payout Simulations

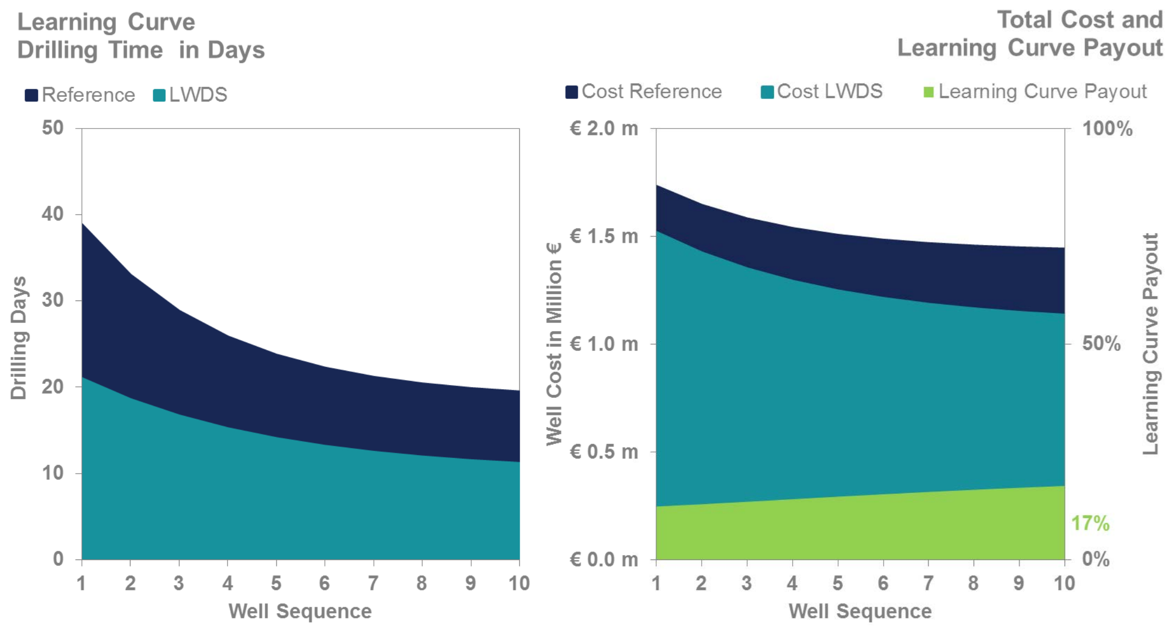

Figure C.1.: Results of scenario 1 LCP simulation.

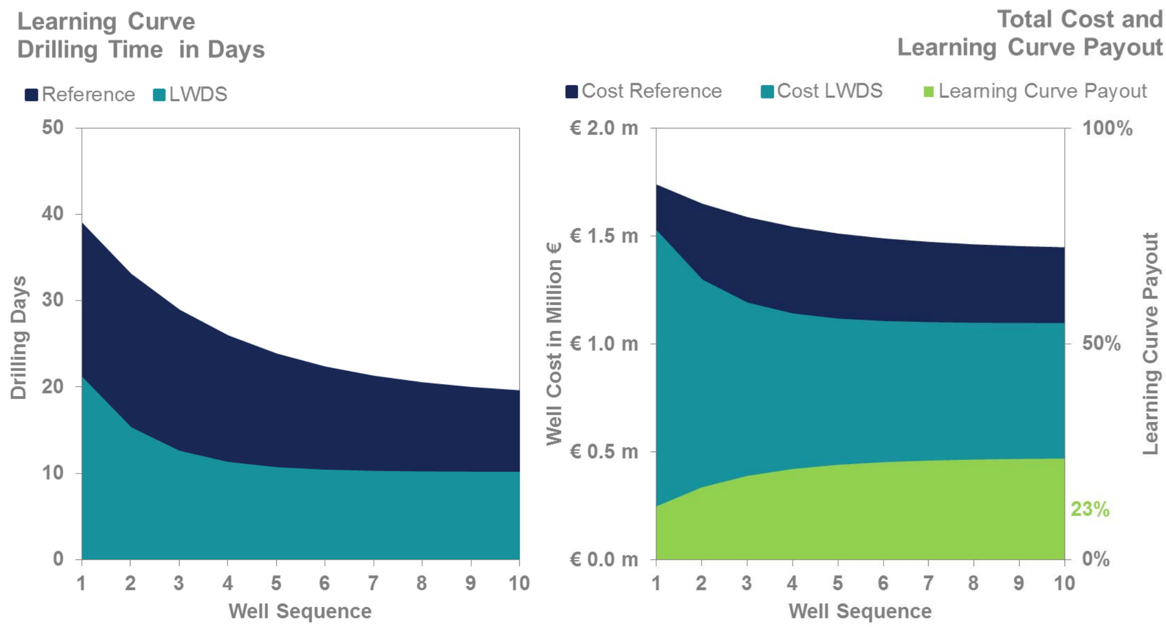

Figure C.2.: Results of scenario 2 LCP simulation.

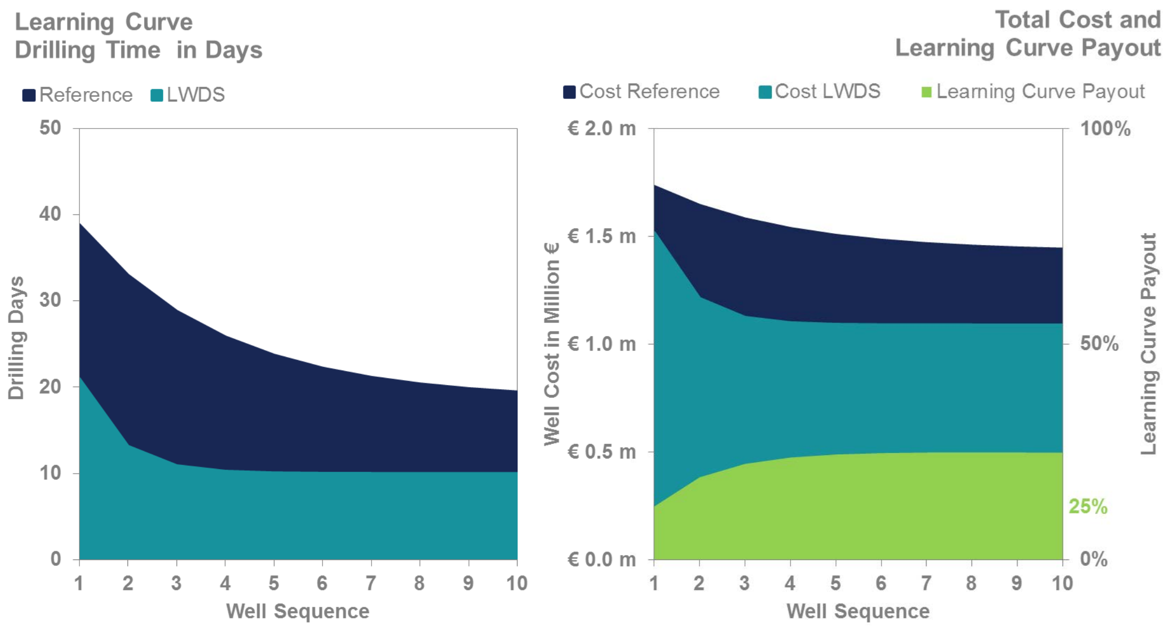

Figure C.3.: Results of scenario 3 LCP simulation.

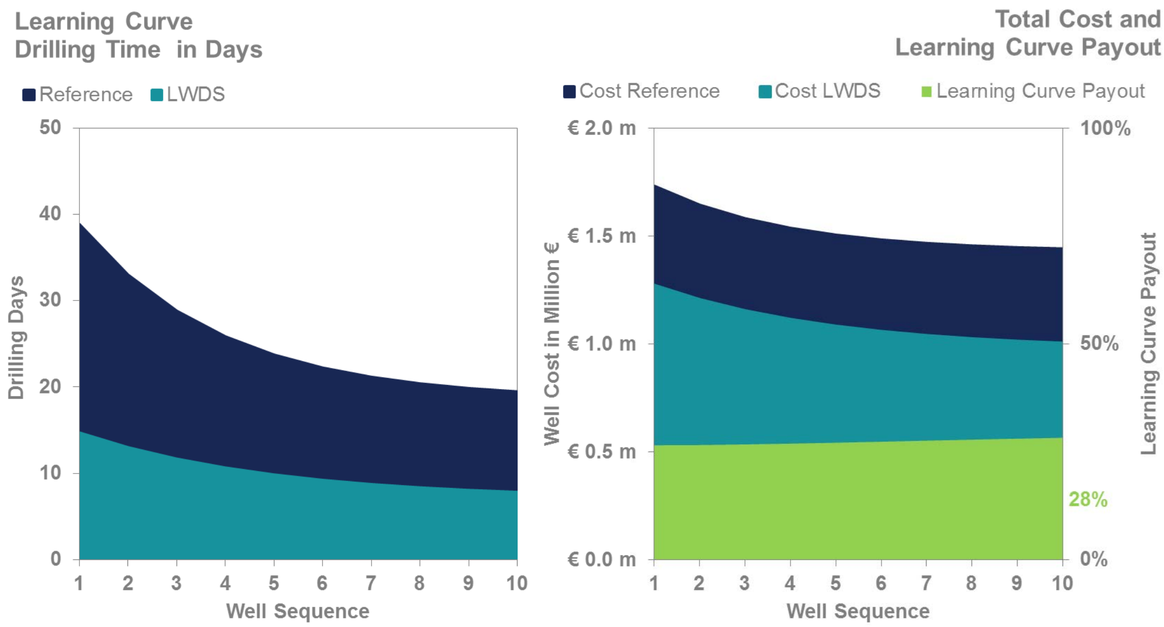

Figure C.4.: Results of scenario 4 LCP simulation.

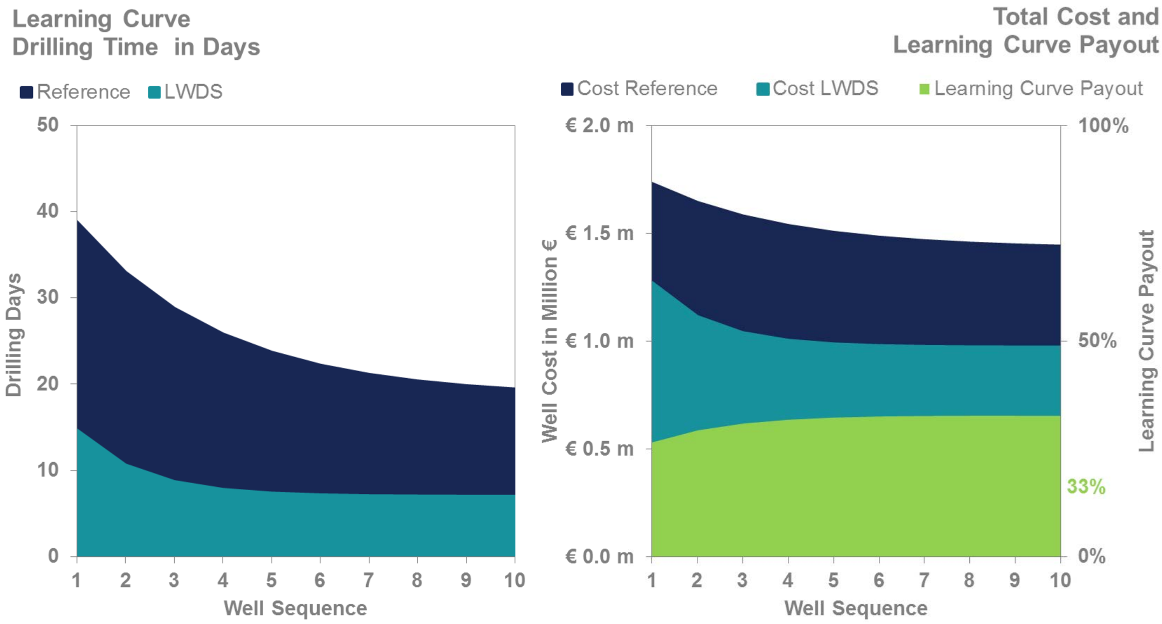

Figure C.5.: Results of scenario 5 LCP simulation.

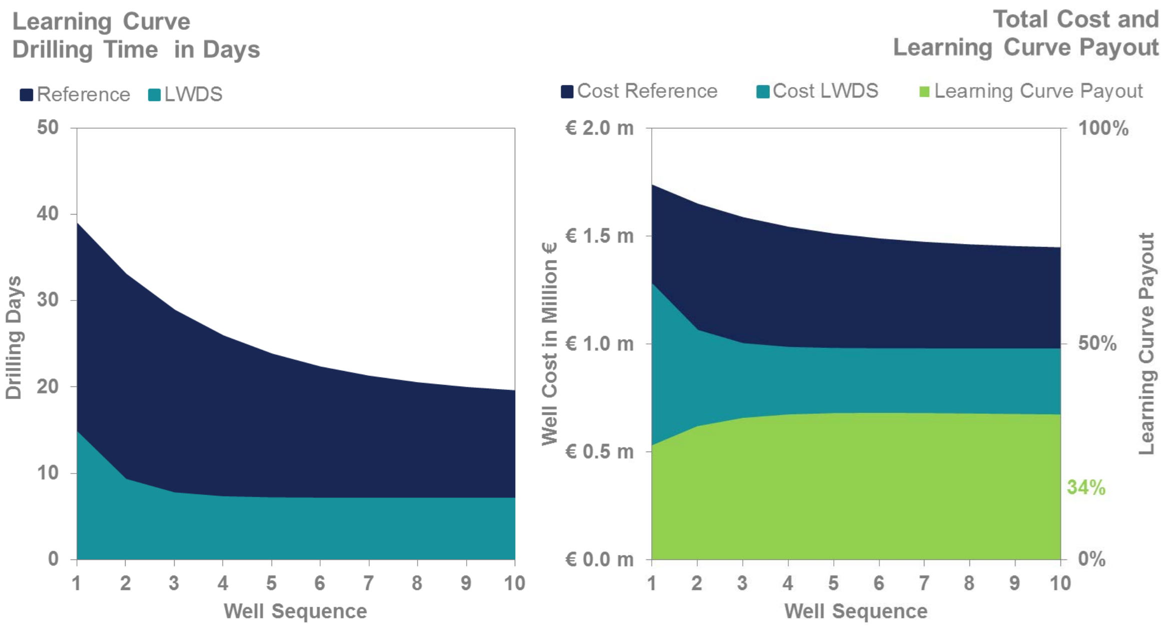

Figure C.6.: Results of scenario 6 LCP simulation.