Novel concepts to construct cost effective geothermal wells with Electro Pulse Power Technology

Specification for the development of the EPP (– CwD) concept and evaluation of economic benefits

Deliverable D1.2

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Executive Summary

Developing drilling equipment is challenging because of the extreme operational environment, unpredictable subsurface and very specific equipment requirements. Introducing novel tools, especially using innovative, non-mechanical cutting technology requires a proper understanding of all requirements. Electric Pulsed Power (EPP) based systems can offer unique benefits and opportunities to the drilling industry and those relying on deep wells such as the fast-developing geothermal industry.

This document, deliverable D1.2 according to the DEEPLIGHT project plan, contains three sets of specifications and requirements of the EPP tool that can be used in real environment either as commercial or pilot system. Several design and operational considerations are included in this document to assist the tool developers in building a tool that meets real-life drilling operations requirements. These considerations are based on existing best practices and cover insights and topics such as design factors, hydraulics, directional drilling, downhole power generation and system integration in the rig environment.

This document is a continuation of the work previously done in the DEEPLIGHT project and reported in DEEPLIGHT deliverable D1.1 [1]. This deliverable describes the geological environment of scenarios identified by the consortium partners which are actively involved in drilling projects. Three possible cases in Turkey, The Netherlands and Iceland are used to define dimensional, environmental, load limits and requirements. All listed specifications and requirements have been aligned with existing drilling standards and related equipment such as the drilling rig, trucks, or handling tools. The specifications defined requirements for three variations of Electric Pulsed Power (EPP) tools of which two cover the most prevailing hole sizes and a more advanced Casing-while-Drilling (CwD) solution:

1. 12-1/4 x 16” EPP-CwD (The Netherlands)
2. 8-1/2” EPP (Turkey)
3. 12-1/4” EPP (Iceland)

All three of these specified tools can be used in most drilling projects in the world due to the compatibility with standard drilling equipment. The first tool will require additional modifications to the drilling rig as EPP is used as enabler for CwD that brings significant advantages to the drilling process. The latter two tools are specified based on very hot and hard formations where higher drilling rates and improved reliability are required. All cases use water-based drilling fluids instead of more expensive oil-based drilling fluids which have lower electrical conductivity. Examples of drilling fluids specifications are given and range from freshwater to advanced systems with clay inhibition, fluid control and weight additives.

A techno-economic analysis of the three scenarios is made to further guide and prioritize the development direction. Economic benefits are quantified and can be used to develop targets for drilling rates. Reliability is another important benefit and targets for Mean Time Between Failures (MTBF) are given. From this benchmark study, the Turkish 8-1/2” application seems to be the most interesting to base the commercial or pilot tool development. The comparison shows that priority needs to be on ROP improvement over reliability improvement.

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Abbreviations

Abbreviation	Description	Comment
API	American Petroleum Institute	
BHA	Bottom Hole Assembly	
CwD	Casing while drilling	Casing drill string-based system
ECI	Enhanced Casing Installation	Huisman level 3 casing drill system
EOB	End of Build section	
EPP	Electric pulsed power	Drilling bit based on electro pulses
ID	Inside diameter	
IDC	Iceland Drilling Company	
IDP	Isolated drill pipe	
JSA	Junk slot area	Void region between bit blades (or electrodes) to allow cutting removal
KOP	Kick-Off Point	Point in the wellbore's trajectory at which the well path gains inclination
LCM	Lost Circulation Material	
LDA	Lock Down Assembly	

LDD	Lockdown device	Special tool to enable CwD and that connects the drilling BHA to the casing
LWD	Logging while drilling	Geophysical while drilling measurement tool.
MD	Measure Depth	
MTBF	Mean team between failure	Measure of reliability
MWD	Measurement while drilling	Borehole direction control device.
NPT	Nonproductive time	
OCS	Outer Casing String	
OD	Outside diameter	
PDC	Polycrystalline diamond compact	Type of drill bit
PDM	Positive Displacement Motor	Mud motor used to generate torque required for the drill bit
POOH	Pull out of Hole	
PPS	Pulse power source section	Surge voltage source & Control unit
PSS	Power supply section	Rectifier, Transformer & Sealing system
ROP	Rate of Penetration	Drilling rate
RSS	Rotary Steerable System	
TD	Total Depth	
TFA	Total Flow Area	
TVD	True vertical depth	
WBM	Water Based Mud	Water based drilling fluid

1 Introduction

An international consortium is developing a novel drilling tool based on the Electric Pulsed Power (EPP) technology in the DEEPLIGHT project. The innovative rock-breaking mechanism uses ultra-short high-voltage pulses to break rock instead of mechanical forces. This method creates new opportunities to lower drilling costs, especially in very hard rock formations which are challenging to drill efficiently with conventional drilling equipment. The low mechanical loads required for drilling enable other possibilities for improvement such as higher reliability and more freedom in shaping the rock cutting interface.

The development of drilling equipment is complex because of the large variation in drilling environment and applications. On the other hand, in-depth knowledge of high-voltage technology is required to be able to adapt it to drilling requirements. Therefore, the consortium consists of parties with core business activities related to drilling and parties that are developing high-voltage pulsed power technology. Aligning the knowledge of these parties by bridging knowledge gaps is one of the main challenges of the DEEPLIGHT project and to do so, the drilling-oriented parties have defined a series of environments and applications (see DEEPLIGHT deliverable D1.1) which are used to specify three different sets of tool requirements. The key determining factor is hole size which comes with a set of industry standards related to the complete well construction process e.g. casing dimensions, rig interfacing etc. The three different sets are in line with global drilling equipment standards to facilitate troublesome introduction once the technology reaches the pilot or commercial phase.

Chapter 2 provides background and insights on various relevant aspects related to downhole tool requirements expected in a typical geothermal drilling operation. This chapter is added because the EPP technology is very novel for drilling applications and many designers and developers are unaware of potential and known solutions to solve some of the more drilling related design challenges. All paragraphs cover topics that will need to be addressed by the tool designers.

In chapter 3, the three EPP tool requirements and specifications are described. The specifications are based on data from drilling conditions in Turkey, The Netherlands and Iceland. The details of the these scenarios (or cases) can be found in Appendix A. The Turkish and Icelandic specifications focus on hard rock drilling applications direct (drop-in) replacement for conventional drilling assemblies without any further modifications needed. The Dutch application uses unique EPP capabilities for a Casing while Drilling (CwD) application in relative soft tophole application. CwD is described in more detail in paragraph 2.7 and is based on installs casing directly instead of pre-drilling the hole as done in conventional drilling method. CwD technology is promising but uses less reliable drilling reamers for which EPP based technology can give more robust solutions. Chapter 3 also includes a summary of a techno-economic assessment of the benefits of the EPP technology. The purpose is to prioritize the direction of future tool development and piloting based on reliability and drilling performance targets. The assessment is rough and can be found in Appendix B.

In the appendices additional information can be found on:

- how equipment will be physically handled on the rig site (Appendix D) to aid in understanding some of the listed requirements
- examples of 'out-of-specifications' (Appendix C) as it is important to understand that some parameters, e.g. vibrations, will need to be managed explicitly by the client / operator during the usage.
- Complete overview of the specifications for the three systems with extra explanation on the logic of picking the values (Appendix E)

2 Design and Operational Considerations

This chapter will list generic, mostly qualitative features and requirements derived from the three cases but applicable to most global drilling projects opposed to case specific and quantitative specifications listed in chapter 3. This chapter also includes additional explanations of the requirements and other items that will need to be considered by the design team.

2.1 Functional & generic requirements

Various basic requirements focusing on the functionality of the equipment are listed in this paragraph.

<u>Directional control</u>

Directional control for steerability and the possibility to measure position and communicate this to surface in real-time is needed. See paragraphs 2.6 and 2.12 for details on MWD and directional control. Steerable refers to remaining vertical or the deviation from vertical, including kick-off & build section and tangent.

- Requires MWD functionality and/or compatibility: real-time directional information (surveys and tool face) & Gamma Ray logging on an acceptable distance from the bit which is typically <15 to 20m. The MWD tool is a 3rd party rental item. Ideally, a near-electrode sensor package provides data to the MWD tool higher in the BHA that transmits all data to surface.
- Steerable also implies stabilisation to manage the natural build or drop tendency of the drilling assembly.

<u>Standard connections</u>

Drilling industry connections and dimensions to enable compatibility with other BHA components and rig handling.

- Separate powerlines are not desirable in a drilling environment as it will require a major change of handling, prevents rotation and complicate well control significantly. This implies that power will need to be generated downhole (see paragraph 2.9). Alternatively, the use of wired drill pipe. However, the use of wired drill pipe is very rare and will add significant cost while downhole power generation is standard drilling equipment.
- Special drilling equipment uses saver-subs which also may be used as cross-over to the right interface (BHA connection).
- Internal connections and the connections between the different EPP segments can be chosen as per tool requirements.

<u>Design requirements</u>

- Besides outer diameter, also the inner diameter will need to be defined to prevent erosion or high pressure drops. Flow path will need to have minimum changes of direction. See also paragraph 2.11 on flow rate and velocity requirements. It is proposed to limit the (long term) flow velocity to 6 m/s.
- The EPP system need to be able to withstand pressures associated with (total) losses and a gas or formation fluid influx, including the remedial actions such as pumping Lost Circulation Material (LCM).

<u>General drilling requirements and considerations</u>

- Drill pipe, or casing in the CwD case, must rotate to reduce drag and to be able to control the electrodes. Hole cleaning in low angle wells will be predominately defined by flow rate while pipe rotation becomes more important with increasing inclination.
- Ideally, the EPP system should be able to drill the casing shoe tracks to start the drilling operation immediately and avoiding dedicated drill-out trips. Drilling out the cement and float equipment (casing shoe track) is an operation that occurs inside the steel casing shoe track.
- In the case of getting stuck, the BHA will be exposed to jarring and/or overpulls which should not result in leaving (undrillable) junk down hole.

2.2 Rig and BHA interfacing and handling

Drilling equipment as drilling rigs and other BHA components are most often described by API standards or equivalent. This may vary per operator or country. Very specific equipment is used to handle and make-up equipment. A brief overview can be found in Appendix D/

Drill collars are standard drilling components with a specific outer diameter, inner diameter, and connection sizes. The selection of a bit size determines the outer and inner diameter, and connections of the other components in the BHA. See Figure 1 for the standard hole sizes (bit size) and casing sizes. The most used hole sizes in the world are 8-1/2" and 12-1/4".

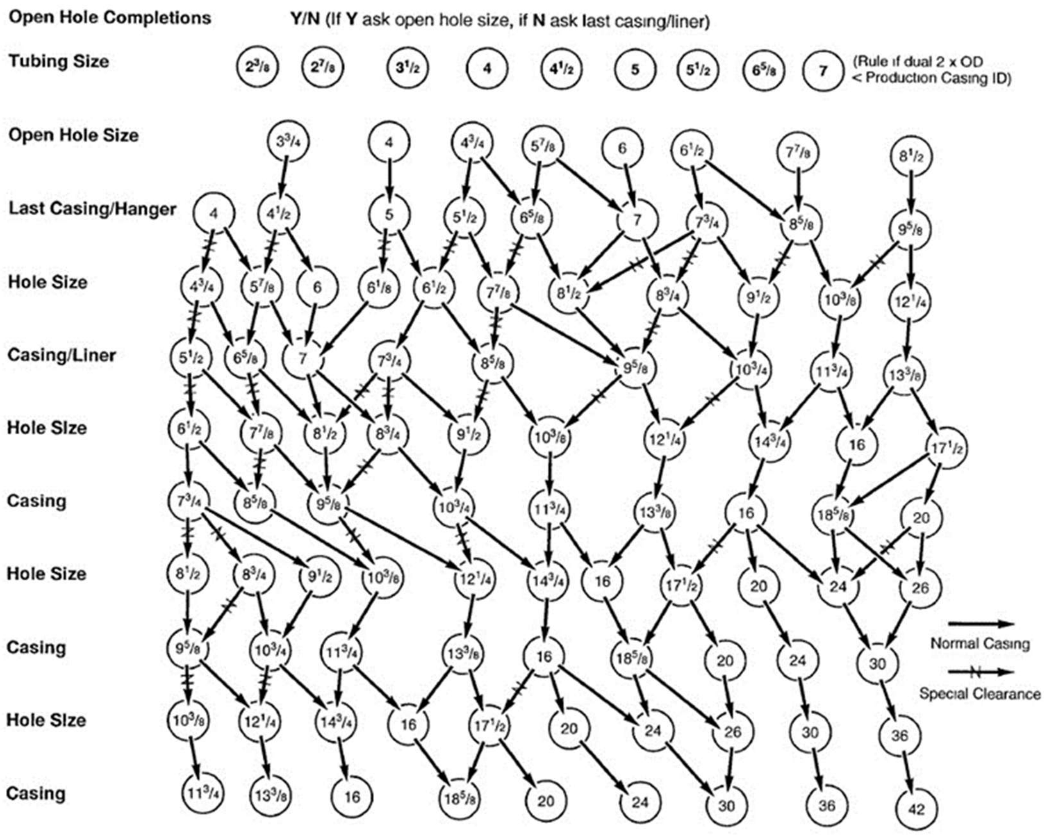


Figure 1. Overview of hole size vs. casing size

To accommodate high-voltage electronic components of the EPP system, drill collars must be modified while still compatible with standard drilling rig equipment and trucks – see Appendix D. That includes handling and making up BHA in bad weather.

Orientation of bit (tool face) should be transferred to MWD hence an orientation mark or other method needs to be present to align EPP tool orientation with the MWD orientation - see paragraph 2.6.

The BHA have directional measurement point in the MWD tool, over 30 m from the bit which is further than mentioned in the required features. This will limit the directional control.

Differential pressure is also limited as the float valve is located above the EPP tool.

The position of BHA stabilizers (distance to electrodes), type (melon, straight, spiral) and diameter will need to be adapted to the specific job requires. Therefore, the EPP collar should be prepared to install sleeve type stabilizers.

2.3 Rig Requirements

With respect to the EPP tool, no special requirements are needed if all high voltages are activated deep enough below the rig floor, therefore, very important will be the operational procedures and safety mechanisms.

For the Casing while Drilling operations, a casing drive or casing running tool is required while drilling. This may cause lengths problems for lower single or super-single rigs. Also, alternative cement float equipment will need to be used, although this has no effect on the rig. CwD requires less pump power what may reduce the required total power and installed mud pump power.

2.4 Drilling Fluids

Drilling fluids, or drilling muds, have multiple functions in the drilling process e.g. wellbore stability, hole cleaning and many more. The drilling fluid will need to be matched to the formation that it needs to stabilise. Water-based or more expensive oil-based fluids can be used. Especially, the water-based muds (WBM) will need additional additives to improve fluid properties such as rheology, clay inhibition and density. Potassium chloride (KCl) is often used to reduce chemical / physical reaction with (clay) formations while adding weight and viscosity. Barite powder can also be used to increase mud weight. Viscosifiers such as starch or polymers are used to increase viscosity and to reduce fluid loss. Oil Based Muds (OBM) are more expensive but easier to be re-used. However, costs can increase rapidly in the case of drilling with losses and therefore WBM or even just water is typically used when drilling through loss zones which are often targeted in the geothermal reservoirs in harder and more brittle formations.

In general, a WBM is saline, and the salinity is expressed in terms of its concentration, usually in parts per million (ppm) or milligrams per litre (mg/L). It can be deducted from reported added materials, e.g., NaCl or KCl, or measured with a special instrument. These instruments typically consist of two electrodes that are in contact with the fluid. An electrical current is passed between the electrodes, and the conductivity of the fluid is determined by measuring the resistance to the current flow. The higher the concentration of ions in the fluid, the higher the conductivity.

When measuring the salinity of a drilling fluid, it is important to ensure that the measurements are taken at the proper temperature and standardized to a specific reference temperature, such as 25°C, to ensure accurate and comparable results. This is because electrical conductivity can be temperature-dependent, and standardizing the measurements allows for better comparison between different samples.

2.5 Bit Hydraulics

Conventional bits (Figure 2) have nozzles to accelerate the mud flow out of the bit to generate more drilling power. Nevertheless, the main function of the mud flow, guided by the nozzles, is to clean the bit and to take cuttings away as effectively as possible through the available flutes or flow area which is defined in Total Flow Area (TFA) in mm^2 or in^2. In 'sticky' formations 'open' bits i.e., high TFA bits are used to minimize bit balling (Figure 3) to efficiently remove cuttings from virgin rock and protecting the EPP Electrode from erosion due to solids loaded mud flow. Therefore, the EPP electrode design will need an 'as open as possible' Junk Slot Area (JSA) to be taken into consideration while maintaining the structural integrity to withstand weight on bit and torque. A Computational Fluid Dynamics (CFD) modelling is required to ensure an even flow over all areas for proper cleaning.

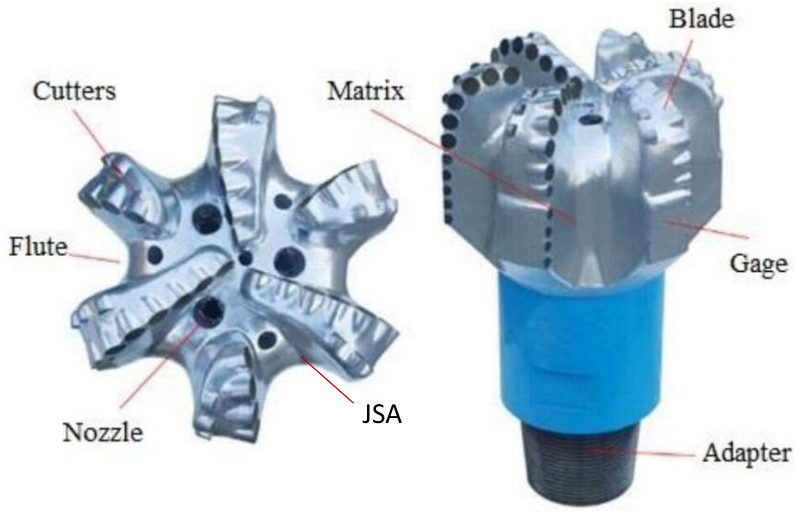


Figure 2. Overview of PDC bit showing the flow areas and nozzles which are used to keep the bit free from drilled formation.

Figure 3. Balled up PDC bit. Bit balling can occur in water sensitive formations and mainly happens with water-based muds. Therefore, the EPP tools will need to have a proper JSA and several adjustable nozzles to optimize bit cleaning.

2.6 Measurement While Drilling

Measurement-While-Drilling (MWD) tools are used to communicate downhole data to surface. This is mostly done using pressure fluctuations by restricting the mud flow through the tool. These pressure fluctuations are measured by a pressure transducer on the standpipe or manifold of the rig. The MWD tool measures 3-axis orientation in the earth gravity field and 3-axis orientation in the earth's magnetic field. From these 6 data points the tools inclination and (magnetic) azimuth is calculated. Together with the surface measured depth these 3 data points form a survey and from the series of consecutive surveys the well trajectory and tool position is estimated. The MWD tool is also used to measure the orientation versus as left - right or North - South or up - down what is needed to steer with certain tools. More advanced measurements such as downhole shocks & vibrations and the background radiation to differentiate between the varies formations can also be measured by MWD tools. A basic working principle of a MWD tool is described in Figure 4.

Some MWD tools can also collect data from other subsurface tools and send this data also to surface. This data contains mostly more advanced geological measurements, and these tools are called Logging-While-Drilling (LWD) tools.

MWD tools and services can be rented from Directional Drilling service companies or purchased from specialised companies. The long distance between bit and MWD measurements points will need to be resolved. A solution could be to install a directional measurement package in the EPP tool and connect it with wires or wireless with the MWD tool. Solving this issue will require cooperation with a Directional Drilling equipment provider.

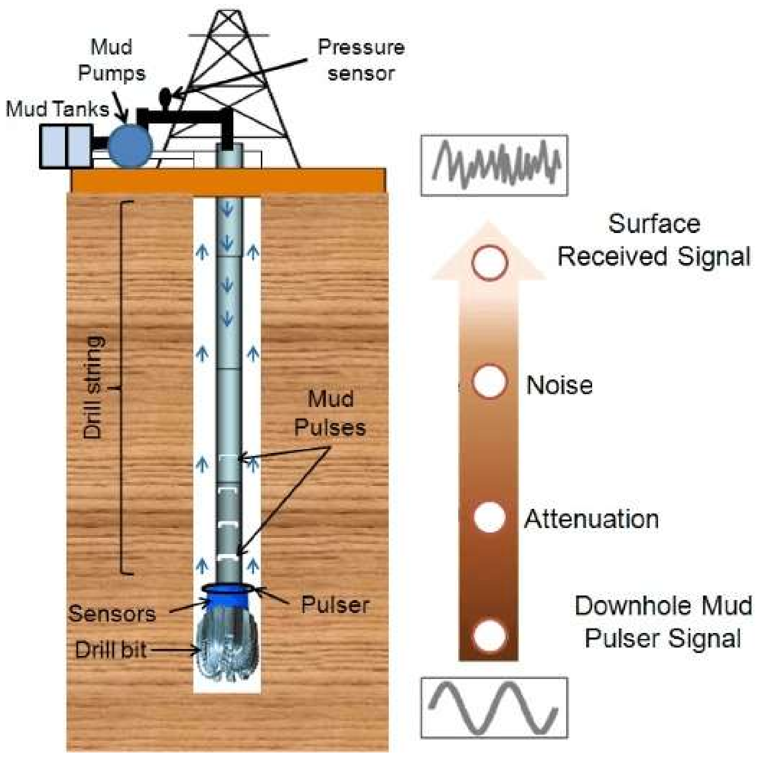


Figure 4. Working of a MWD tool.

2.7 Casing While Drilling

Casing while Drilling (CwD) is an advanced drilling technique where the casing is used to rotate and/or pump through during its installation. Different levels are defined as shown in Figure 5 with conventional drilling using drillpipe pictured on the left.

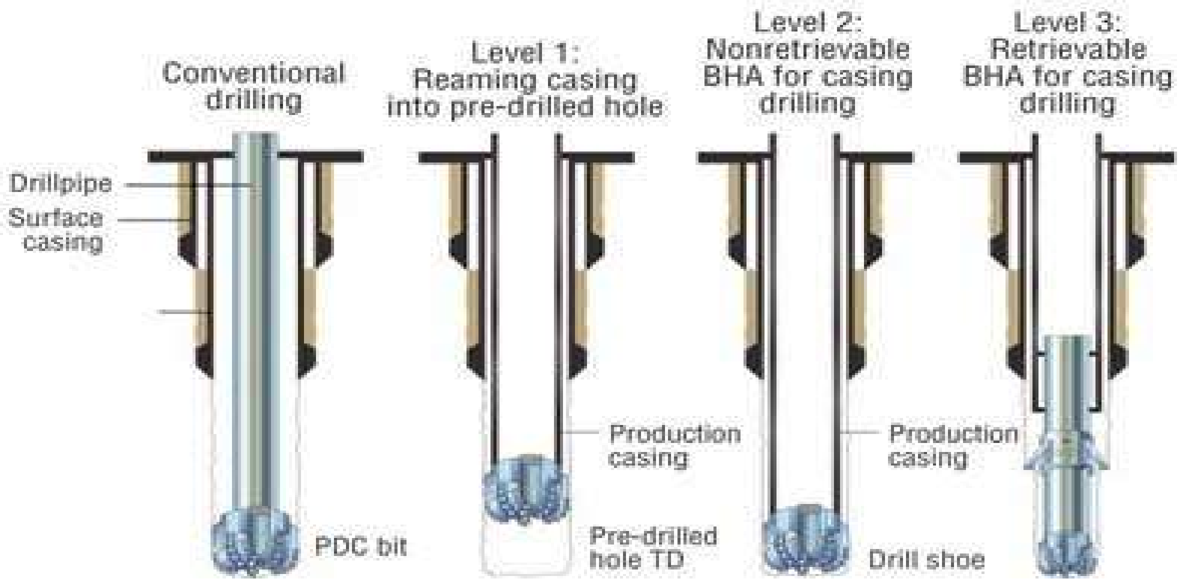


Figure 5. Conventional drilling together with a level 1 CwD setup is mortly used these days to install casing. A level 3 system is proposed to combine with EPP drilling.

Level 1 CwD is used in combination with conventional drilling to minimise potential installation problems and to speed up operations. For EPP, a retrievable and directional BHA is needed hence level 3 CwD. Benefits of (directional) CwD are:

- Casing in place when TD is reached, minimum of open hole time: excellent for wells with losses, swelling clays or other formation related problems. Gives more flexibility in casing setting depths.
- Currently, the planned build rates are limited to minimise casing installation issues due to the large (stiff) casing diameters in soft formations. Build rates can be increased when installing casing while drilling offering more design options, lower risk, shorted/cheaper wells
- No open hole so maximum tripping speeds possible over full lengths because no formation related risk present.
- Short BHA's, no drill collars/jars used and a minimum of BHA & pipe handling.
- Light BHA's, without formation risks present, may be retrieved by cable (>2000 m/hr instead of ~300m/hr trip speed) what can save time (up to 50%)
- No time lost on check trips or extra hole cleaning (no back reaming etc.)
- Less pump power needed due to higher annular velocity (better hole cleaning)
- Simpler, and therefore cheaper, mud systems used as open hole time is shorter, drilling with lower mud weight possible.
- Safer: pipe handling causes most accidents in the drilling industry
- Less shocks, vibrations, and stick & slip, due to the large diameter pipe, resulting in more efficient drilling and less equipment failure.
- Dynamic kill possible for drilling shallow gas so no pilot hole needed.

- Drill smaller boreholes (lower borehole / casing size ratio) what results in less cuttings, cement drilling fluid. Gives more flexibility in casing design. Hole vs casing size is somewhat standardized according to the flow chart in Figure 1.

A level 3 CwD system requires modifications to the BHA and rig. The BHA will require a special tool to connect to the casing, i.e. the Lock Down Assembly (LDA) or Lock Down Device (LDD). The LDA or LDD requires a special casing sub near the bottom of the casing string for accurate positioning and the transfer of drilling forces. The rig will need to be equipped with a casing drive below the topdrive. Furthermore, some special subs and tools are required to set and retrieve the BHA and for well control. The BHA can be retrieved on drill pipe once final drilling depth is reached. Due to the low weight and absence of open hole related risks such as overpull, a slickline winch may be used to what will give significant time savings.

A crucial element is that a hole needs to be drilled large enough for the casing plus upward mud flow by a device that can fit through the inside of that same casing. This is conventionally done with an under-reamer using expandable drilling blocks (see Figure 6) or a bi-centre bit which is an asymmetric bit that, when rotated, drills a hole larger than its diameter. The latter is displayed in Figure 7 and can be used as example for an EPP-CwD bit/reamer. Underreamer for CwD requires an enlargement, i.e. hole size vs. tool body size, of ~30-50%. Regular reamers suffer from the large torque over such long reamer arm plus the large rotational speeds at the tips. For larger casing sizes a relatively less oversized hole can be used what is more cost effective due to lower mud and cutting disposal costs.

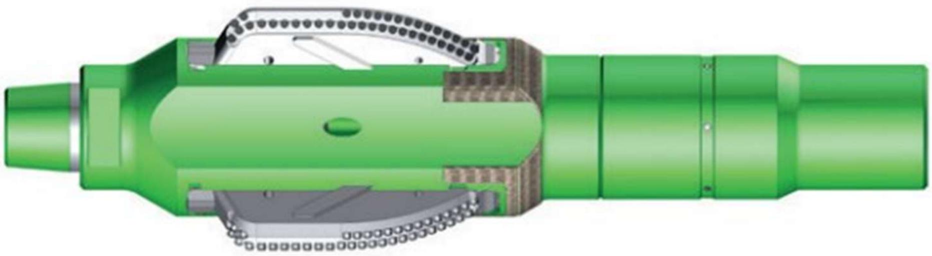


Figure 6. Drillstar Z-reamer with expandable drilling blocks in drilling position (open) capable of drilling a 17-1/2" hole. In closed position the body will fit through a 12-1/2" pilot hole which is the standard bit size to fit through a 13-3/8" casing.

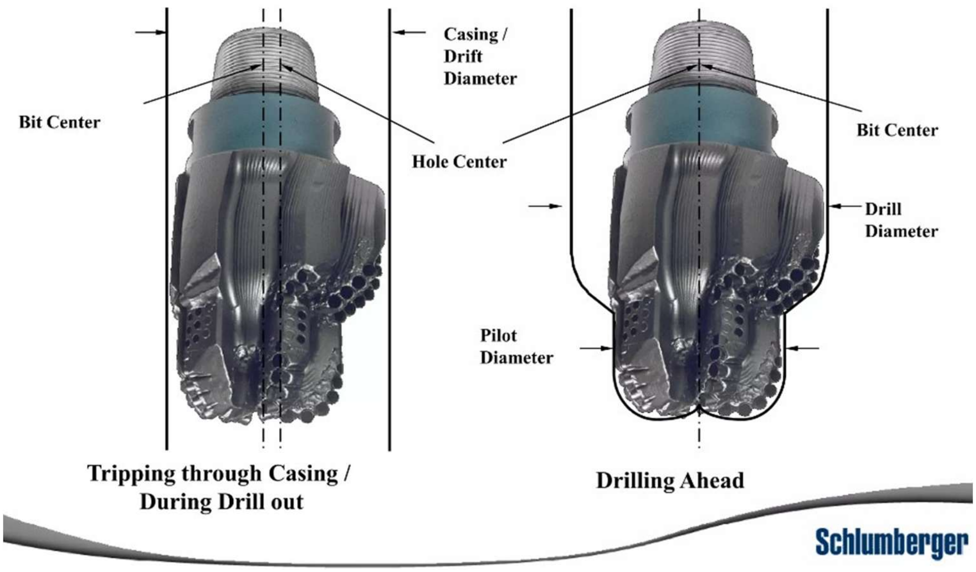


Figure 7. Example of bi-center bit.

The components of the Huisman level 3 CwD system named Enhanced Casing Installation (ECI) system are pictured in Figure 8. In the BHA, the bit & reamer and steerable tool (PDM or RSS) will be replaced with the EPP system.

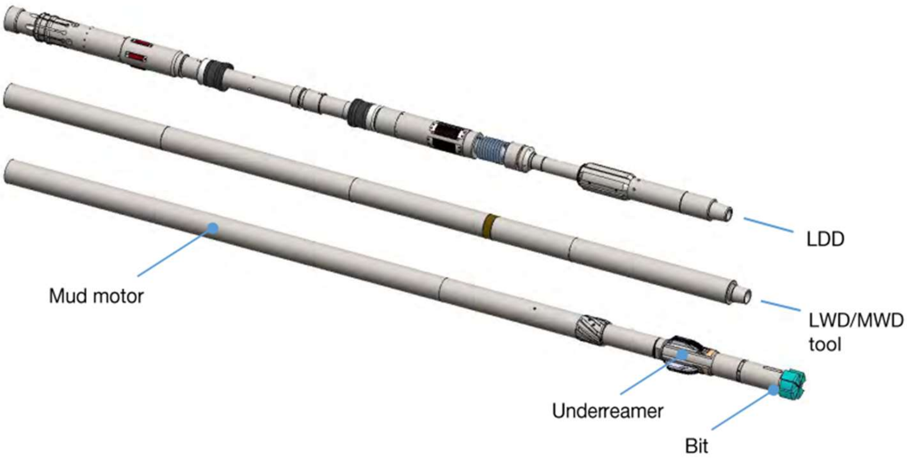


Figure 8. Example of a possible BHA setup using Huisman ECI components. The mud motor, underreamer and bit will be replaced by the EPP assembly.

Several companies offer CwD services such as SLB with Allegro[1], Weatherford with dDwC[2] or Huisman Well Technology (HWT) with ECI[3]. Unique for the Huisman system is the use of a casing extension below the Lock Down Device called OCS as shown in Figure 9.

HWT developed a mechanical rotary steering system (Syncrodrill) specifically for casing drilling by leveraging the high torsional stiffness of casing opposed to drill pipe. The method could be an option for EPP.

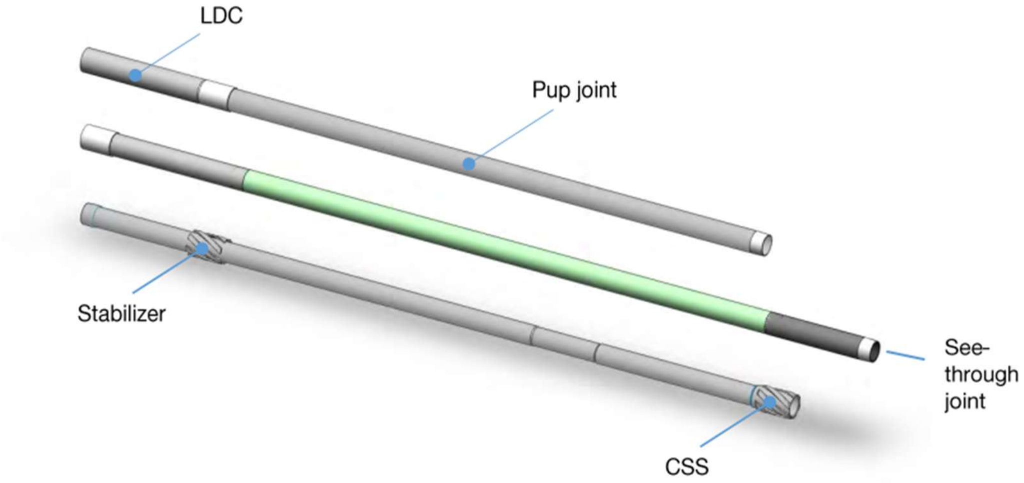


Figure 9. Example of an OCS (Outer Casing String) setup of the Huisman ECI system.

[1] www.slb.com/videos/allegro-cd-service-improving-well-economics
[2] www.weatherford.com/products-and-services/drilling-and-evaluation/drilling-services/drilling-with-casing/directional-drilling-with-casing/
[3] www.huismanequipment.com/nl/products/drilling/well_technology/enhanced_casing_installation_eci

Liner drilling, instead of casing drilling has not been considered as it requires modifications to the liner hanger what is considered out of scope of this project.

2.8 High temperatures & cooling

Cooling may become important in very high temperature environments. Such high temperatures affect all equipment and materials in the well so not just the EPP tool, but also MWD/LWD equipment, mud, cements, drill pipe and casing.

In the last few years, the most temperature sensitive equipment (equipment with electronics) has been improved from a typical temperature rating of 150°C to 175 °C, but the most important way to manage temperature is to circulate cool drilling fluid from surface. To cool drilling mud at surface, large surface tanks are used to enable sufficient evaporation and/or mud coolers can be used (typically offshore or hot wells). An example of a mud cooler used in Iceland is given in Figure 10.

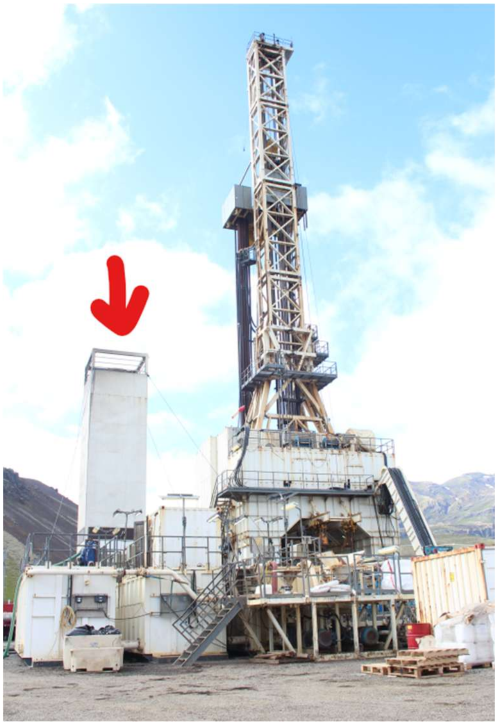


Figure 10. The red arrow points to the mud cooler of IDC's 350-ton rig

From the gathered data in D1.1 it was already visible that drilling temperatures in general are lower than the down hole temperatures. This can be modelled and measured as done by Eavor [2] and is depicted in the Figure 11. The blue curve demonstrates the benefit of using coated drill pipe that provides thermal isolation.

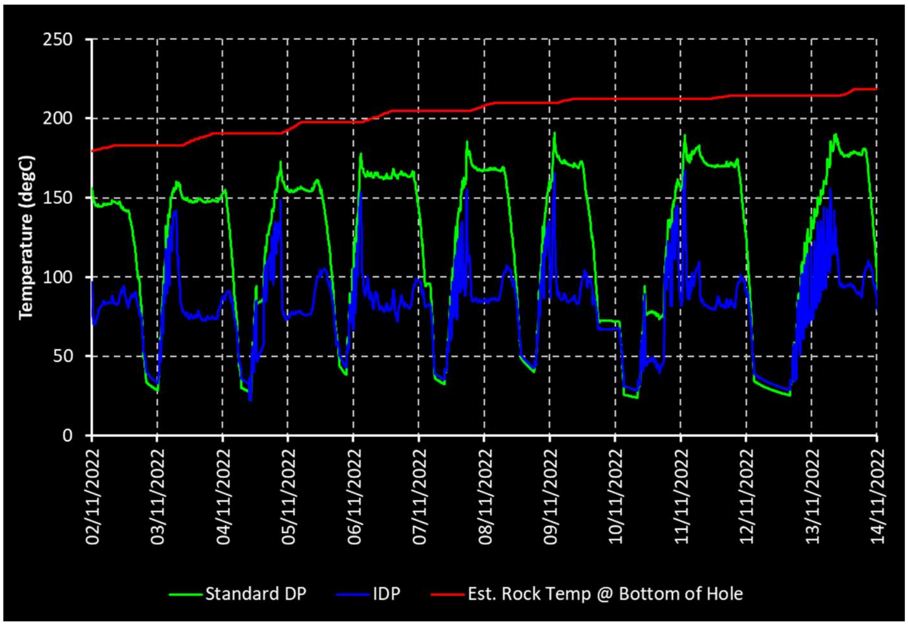


Figure 11. Modelled cooling effect of mud circulation on BHA temperature with standard and isolated drill pipe [2] for a series of BHA trips. It can be seen that a BHA below standard drill pipe reaches higher temperatures. Also visible is that the highest temperatures are reached right after tripping in hole.

The temperature fluctuations are caused by tripping out and back in to change out bit or BHA components. Both the green and blue curves show a peak after these round trips. The blue curve, showing the Isolated drill pipe (IDP) values, drops quickly when circulation is re-established. According to Eavor, it takes up to 230 minutes to reach 150 ˚C when using IDP. The modelled average tool temperatures are significantly lower when using isolated drill pipe but the variations in temperature are higher what may result in more fatigue. Normal practise in high temperature wells is to break circulation on regular intervals while tripping in. The case shows the importance of mud flow for cooling: the higher and more continuous the flowrate, the better the cooling will be.

Short circulation breaks occur during drill pipe connections. A solution to prevent the temperature increments and variations during connections is a continuous circulating system. Such systems are used to maintain constant downhole pressure in complicated wells and have the additional advantages of providing continuous cooling and hole cleaning. The latter means that no shear-thinning requirements for the mud is needed hence simpler mud systems can be used. Obviously such a such a system adds cost and complexity.

2.9 Downhole Power Generation

Downhole electricity can be generated by converting hydraulic power, i.e. drilling fluid pressure and flow, using a turbine or positive displacement motor. The difference between the two is visualised in Figure 12. The turbines offer higher rotation speeds, do not depend on fluid/temperature dependent elastomers, create less vibrations and cannot stall. On the other hand, the rotors and stators (combined a power section) of positive displacement motors (PDM) or mud motors are standard, commercially available drilling equipment. An (overpowered power) section may be most practical and economical in cooler environments while turbines (or the less common metal stator power sections) are more suited in high temperature environments.

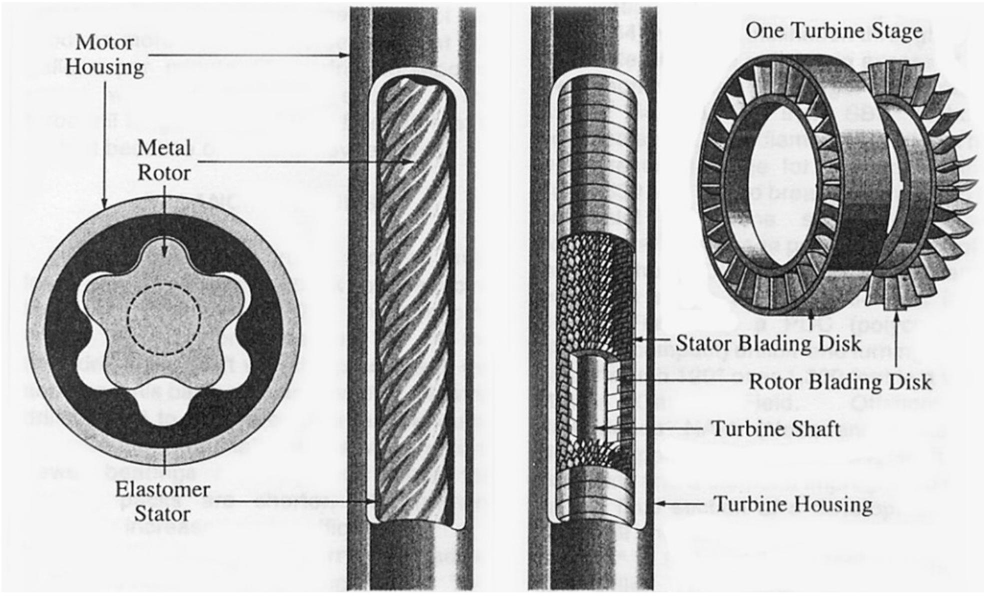


Figure 12. Comparison of Mud Motor Power Section (Left) and Turbine (Right) [3].

In a turbine, torque and bit speed are dependent on each other, but this is not so within a PDM. There, the rotor/stator configuration is what controls the torque/bit speed relationship.

2.10 Collar length & internal connections

The EPP tool subject of the DEEPLIGHT project is likely to be assembled on-site from different parts, which means that mechanical, hydraulic, and electrical connections need to be made under various weather conditions on the rig. Threaded collar connections have a limited lifetime and need to be able to recut to avoid scraping expensive collars. A recut, or shortened collar, requires internal connections to be adapted accordingly. Therefore, extenders with adjustable lengths are used. Extender connections are standard used in the O&G industry to low voltage electrically connect MWD together with LWD modules, this extension allows (limited) rotation during modules make-up of the threaded collar connections. An example of an extender is presented Figure 13. In Figure 14 and Figure 15 extenders are shown inside M-LWD collars.

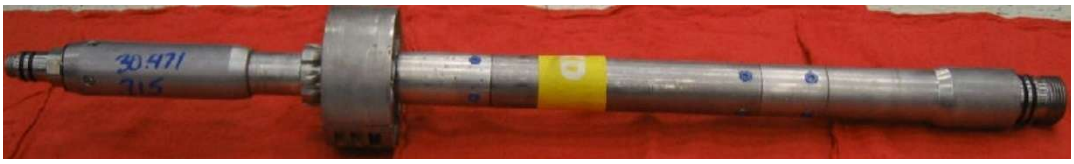


Figure 13: Example of an LWD Extender

Figure 14: Male extender installed in collar

Figure 15: Female extender installed in collar

2.11 Tool Layout & Dimensioning Criteria

In general, most electronic packages in drilling tools are placed concentrically and at the centre of the tool (configuration 1 in Figure 16) to minimize the impact of rotational variations, shocks, vibrations, or bending during drilling, which could stress internal components. This placement also simplifies the design, construction, and maintenance of the tools. Based on a maximum allowable flow velocity [m/s] and the maximum flow rate [m^3/s], the internal diameters can be determined. The differential pressure rating, i.e. pressure between in- and outside of tool, will provide the required collar thickness.

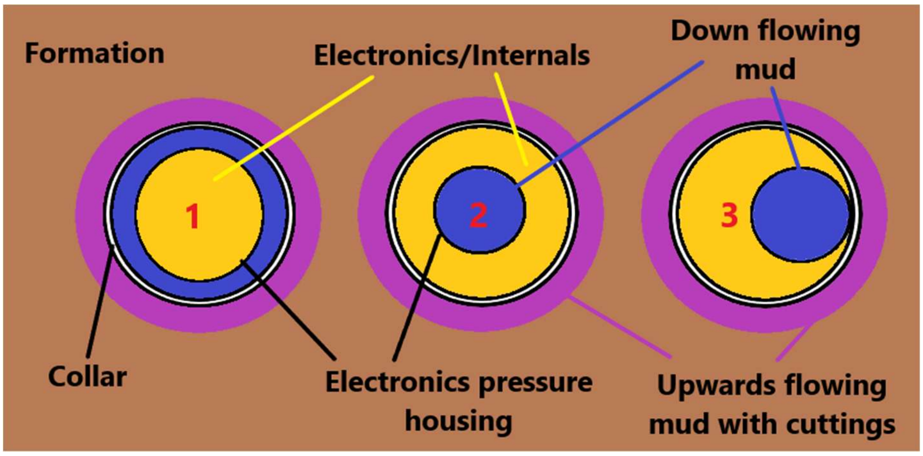


Figure 16. Cross-sections of 3 possible tool configurations.

To optimize the dimensions of the electronics pressure housing, two different flowing velocities for WBM were considered. The allowable velocities were sourced from the maximum flowing velocities of 6 m/s (API 14E) for long-term flow rates and an even higher velocity of 8 m/s provided by telescope collars for short-term rates. These flowing velocities set the limits to establish dimensions for configurations 1 and 2 in Figure 16. Based on the maximum flowing velocity and long-term flowrate mentioned earlier, we calculated the nominal flow rate provided by the wellbore section to be drilled for each scenario, as well as the maximum flow rate of the corresponding Telescope tool coinciding with the BHA to be used. Subsequently, we computed equivalent flowing areas for EPP electronic collars (in this analysis, casing bodies), ensuring they maximize the available volume to accommodate EPP electronic parts.

Table 1: Maximization of Space to Host Electronics within a 9-5/8" OD Casing Body

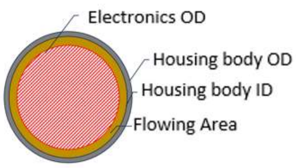
Scenario 1

Input Data

Hole size	Housing Body ID	Continuos Max Velocity	Short-Term Max Velocity	Nominal Max Flow Rate	Short-Term Max Flow Rate
[in]	[mm]	[m/s]	[m/s]	[l/min]	[l/min]
17-1/2	226.6	6	8	3400	4500

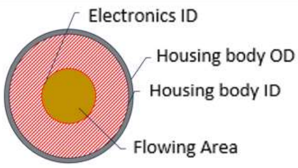
Results

Annular Flow



	TFA	TFA
	[mm2]	[mm2]
	9444	**9382**
	Electr. Housing OD	Electr. Housing OD
	[mm]	[mm]
	198.3	198.5
		Smallest possible flow area

Inner Flow



	TFA	TFA
	[mm2]	[mm2]
	9503	12469
	Electr. Housing ID	Electr. Housing ID
	[mm]	[mm]
	110	126
	Smallest possible flow area	

Table 2: Maximization of Space to Host Electronics within a 7" OD Casing Body

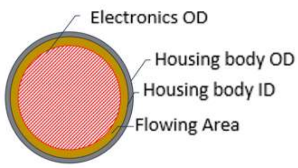
Scenario 2

Input Data

Hole size	Housing Body ID	Continuos Max Velocity	Short-Term Max Velocity	Nominal Max Flow Rate	Short-Term Max Flow Rate
[in]	[mm]	[m/s]	[m/s]	[l/min]	[l/min]
8-1/2"	164.0	6	8	1700	3000

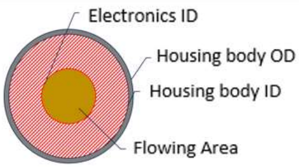
Results

Annular Flow



	TFA	TFA
	[mm2]	[mm2]
	4833	6378
	Electr. Housing OD	Electr. Housing OD
	[mm]	[mm]
	144	137
	Smallest possible flow area	

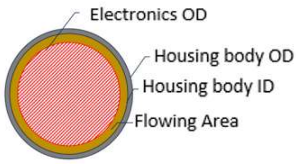
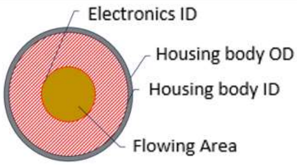
Inner Flow



	TFA	TFA
	[mm2]	[mm2]
	4778	8495
	Electr. Housing ID	Electr. Housing ID
	[mm]	[mm]
	78	104
	Smallest possible flow area	

Table 3: Maximization of Space to Host Electronics within an 8-5/8" OD Casing Body

Scenario 3
Input Data

Hole size	Housing Body ID	Continuos Max Velocity	Short-Term Max Velocity	Nominal Max Flow Rate	Short-Term Max Flow Rate
[in]	[mm]	[m/s]	[m/s]	[l/min]	[l/min]
12-1/4"	198.8	6	8	3600	4700
Results					
Annular Flow				TFA	TFA
				[mm2] 10000	[mm2] **9900**
				Electr. Housing OD	Electr. Housing OD
				[mm] 164	[mm] 164 **Smallest possible flow area**
Inner Flow				TFA	TFA
				[mm2] **10000**	[mm2] 13000
				Electr. Housing ID	Electr. Housing ID
				[mm] 113 **Smallest possible flow area**	[mm] 129

Configuration 1 and 2, as per Figure 16, exhibit no significant difference in available Total Flow Area (TFA). However, configuration 1 features an approximately 2 times larger contact area between the electronic pressure housing and mud. Therefore, configuration 1 is the preferred setup in a high temperature environment considering that contact area is a measure for heat transfer. To achieve good results, good heat conduction between the electronics, collar/housing and mud flow path sections is required.

2.12 Directional Control

Directional wells are drilled because of many different reasons of which surface space usage is an important one. Directional drilling in geothermal applications allows to drill the producer and injector wells from the same location near the power plant. Maintaining verticality also requires directional control.

In general, directional control is exercised by controlling and managing 3 contact points of the bottom part of the drilling assembly as shown in Figure 17. Initially this was done by placing stabilisers with different diameters and distances to the bit to control the forces on the bit and its tilt angle. Later, more active methods were introduced by active tilting and orienting/tilting the bit by introducing a bend e.g., mud motor or point-the-bit rotary steerable tools (RSS), or by directly applying a side-force to the bit e.g., push-the-bit rotary steerable tool.

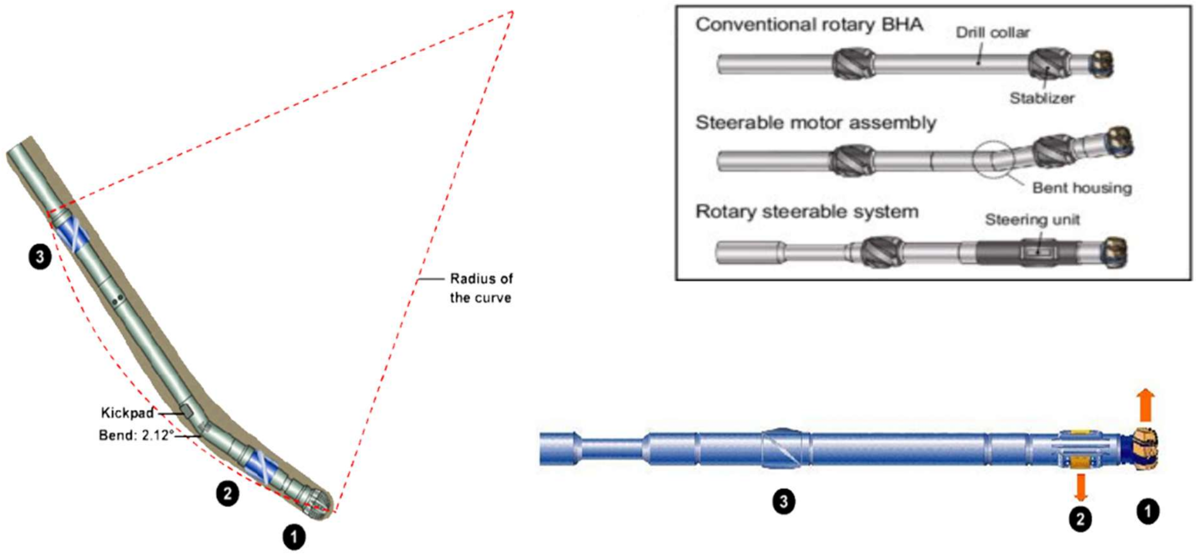


Figure 17. Basics of the directional control with on the left the visualization of the A 3 contact points defining the BHA geometry and the resulting direction. On the right top, 3 techniques to steer and on the right bottom, a push-the-bit RSS is shown.

The required deviation is obtained by utilizing a near-bit pivot point or even a bit shaft with an offset angle. Directional control is achieved by providing 3-touch points in contact with the well-bore.

Steering with a PDM with bend is done by rotating drill pipe at surface to drill without pipe rotation while aiming the bend in the desired direction, so called sliding mode, see Figure 18. This is the simplest, and therefore probably most relevant solution, for directional EPP drilling. This can also be done by using an asymmetric electrode.

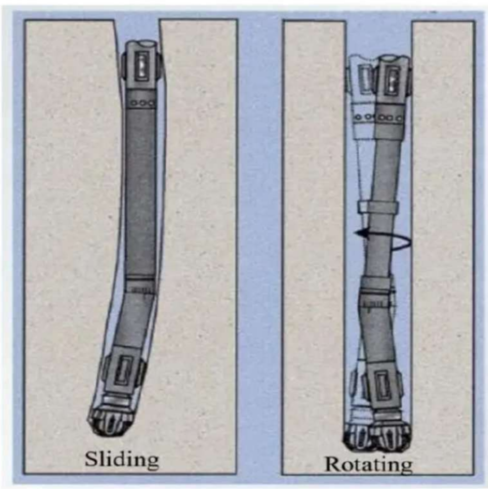


Figure 18. Sliding vs Rotating (Warren, 2006)

Stabilizers are used to transfer BHA (side-)forces caused by BHA weight and bending to the formation. Different types exist such as string stabilizers or sleeve types which are installed on a threaded housing for example on a PDM – see Figure 19.

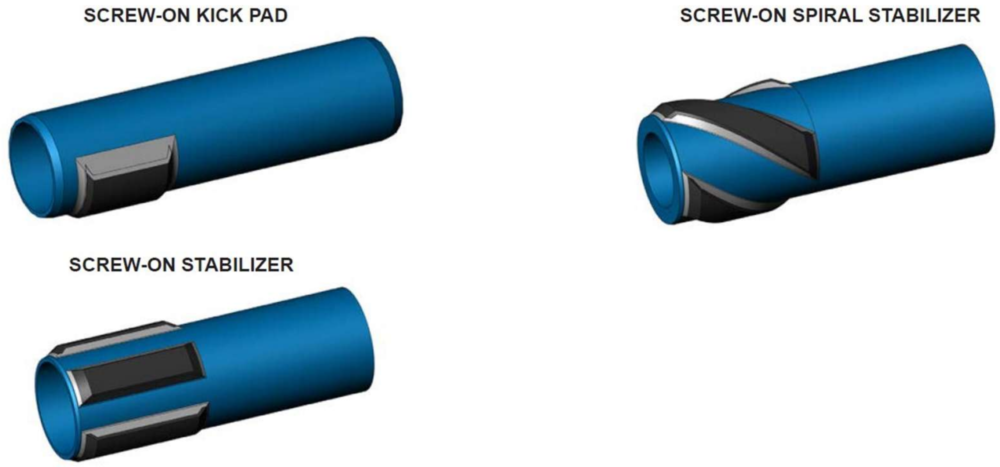


Figure 19. Different types of sleeves used to stabilise a PDM.

2.13 Weight on Bit & Rotation

Opposed to mechanical rock breaking methods, no rotation or axial load is needed to make the EPP tool to break a rock. The loads on the electrodes and electronics should be limited to prevent damage. Nevertheless, some Weight-on-Bit (WOB) is needed to ensure contact with the formation. The amount of WOB can only be as low as the driller can control. To get a more controlled weight transfer, the drill pipe needs to rotate to minimize friction. The pipe rotation is also needed to assist in the transportation of drilled cuttings to surface in wells with higher inclination. Specifically, for EPP, rotation will ensure that rock is cut evenly and not only around the electrodes. In all cases of rotation with any WOB present, torque will be generated.

For low angle sections, low top drive revolutions per minute (RPM's) can be used and a shock-sub (or bumper-sub) can be used to limit the weight-on-bit. The concept of a shock-sub is to disconnect in axial direction the part of the drilling string above and below the shock-sub and to reduce the weight transfer over the stroke of the sub.

Alternatively, to a shock sub, a thruster sub specifically designed to control WOB over the EPP electrode could absorb detrimental shocks. A thruster prevents overloads when high drags make controlling the weight and bounce effects over the EPP electrode.

High angle wells (>60° inclination) require high strings RPM (>100) for hole cleaning. To reduce the rotation of the bit some sort of slip coupling could be developed as these are currently non-existent for drilling operations.

2.14 Design & test factors

In the specifications certain design / safety factors will be used to accommodate uncertainties and to ensure that robust engineering is performed on the relevant parts. Also, sufficient margin is needed to test equipment so that it can be physically validated that equipment is fit-for-purpose.

Typically, 1.5 is used on top of the expected maximum operational value for pressure, torque or force.

To test, or qualify, equipment a value of 1.25 is suggested of the maximum expected operational value.

3 Specifications and Technical Description

This chapter describes the three sets of EPP system specifications and requirements. These specifications are derived from the 3 country cases deducted from the scenarios defined in DEEPLIGHT D1.1. These sets define 3 different tools and are aligned with standard drilling requirements, as defined in chapter 2, to facilitate future implementation beyond the reviewed cases. The described tools can therefore not only be used in the specific Turkish, Dutch or Icelandic applications but in most drilling projects in the world. The main difference is in the hole size being drilled. Therefore, a case specific set of data will be given plus an additional set of general specifications. The scenarios and the final selection can be found in appendix A. This chapter also contains Bottom Hole Assembly proposals for each application to provide insight in the EPP usage but also in additional equipment requirements which are not part of the EPP scope.

3.1.1 System 1 – 12.25" x 16" EPP-CwD

The first set of specifications is based on a great majority of wells directionally drilled in the Netherlands (see Appendix A, case 1). It is important to note that the directional drilled wellbore will pass through different sedimentary rock types, which are generally easily drilled with conventional Polycrystalline Diamond Compact (PDC) bits, while the hole cleaning and cutting handling limits the maximum ROP. In contrary, in CwD the limiting factor is not the bit but the underreamer or bit – underreamer interaction. The reason in the latter case is due to different mechanical interaction with the formations which may result in poor drilling performance, vibrations, or complicated drilling assemblies. An EPP version of a combined bit and under-reamer may unlock the casing while drilling promise.

3.1.1.1 Application and Benefits

The focus of this sub-chapter will be on an underreamer, or bi-centre bit, functionality as this is enabler for CwD operations. The CwD technology is described in more details in paragraph 2.7. A conventional underreamer or bi-centre drill bit ideally needs to handle the same (high) mechanical drilling loads than a drill bit with a significant weaker mechanical construction due to the opening/closing feature, in the case of the underreamer. Bi-centre bits may deliver under-gauge holes due to unstable cutting action under high load and torque.

There may also be benefits for EPP to use CwD:

- Improved hole cleaning what may help getting odd sized cuttings out of the hole
- Reduced mud requirements hence more freedom to adapt the drilling fluid system to specific EPP requirements.
- Stiffer string causes less shocks and vibrations what may be beneficial for high-tech electronics.
- The stiffer string and more even weight distribution also provides more accurate weight on bit control.

The EPP tool will need to drill a borehole large enough for the casing to pass. In the case of 13-3/8" casing a 16" hole is drilled with a tool body size of maximum 12-1/4". Rock removal should be done at one point only, unlike using a bit with a separate reamer. This means that the electrodes should be adjustable in diameter or foldable.

CwD systems require several modifications to rig and BHA compared to conventional drilling. Commercial casing while drilling providers exist which can provide these modifications. These commercial systems are designed for significant higher torque, axial forces and pressure requirements so alternative and more economical solutions may be already exist and available.

Casing as drill string must rotate for hole cleaning and to reduce drag, typically at 20 rpm as minimum. When the casing is rotated, it creates a plastering effect that is beneficial for the borehole strength.

3.1.1.2Bottom Hole Assembly

The following BHA setup is suggested, see Table 4. The CwD inputs are based on the Huisman ECI drilling system as identified in sub-chapter 2.7.

Table 4: EPP-CwD BHA (inner string) – The Netherlands case

Item	Description	Vendor	Stab OD	O D	I D	Conn.	Length [m]	Cumulative Length [m]	Weight [kg]	Cumm. Weight [mT]
1-a	12-1/4" x 16" EPP- expandable bit (electrode)	IHC		16"			0.5	0.5	25	0.0
						TBD				
1-b	9-5/8" PPS - collar 1 with (sleeve) stabiliser near bottom	IHC	12-1/8"	9-5/8"		TBD	9	9.5	2371	2.4
					TBD	TBD				
2	9-5/8" PSS - collar 2 with (sleeve) stabiliser	IHC	12-1/8"	9-5/8"		TBD	9	18.5	2371	4.8
					TBD	TBD				
3	9-5/8" PDM -Power section - collar 3	IHC		9-5/8"		TBD	9	27.5	2653	7.4
					NA	TBD				
4	8-1/2" Cross-over Saver-Sub	3rd party		8-1/4"		TBD	1	19.5	231	7.7
					3-3/4"	6-5/8" REG box				
5	8-1/2" Bumper/shock sub	3rd party		8-1/4"		6-5/8" REG pin	5	47.6	1157	8.8
					3-3/4"	6-5/8" REG box				
6	8-1/2" float sub	3rd party		8-1/4"		6-5/8" REG pin	1	28.5	231	9.0
					3-3/4"	6-5/8" REG box				
7	8-1/2" NMDC MWD Tool	3rd party		8-1/4"		6-5/8" REG pin	8.5	37	1585	10.6
					NA	6-5/8" REG box				
8	8-1/2" NM Pony Collar	3rd party		8-1/4"		6-5/8" REG pin	4	41	926	11.5
					3-3/4"	6-5/8" REG box				
9	8-1/2" NM String stabilizer	3rd party	12-1/8"	8-1/4"		6-5/8" REG pin	1.6	42.6	370	11.9
					3-3/4"	6-5/8" REG box				
10	13-3/8" Lock Down Device	3rd party	12-1/8"	12-1/4"		6-5/8" REG pin	9.1	56.7	1820	13.7
					3-3/4"	fishing neck				

Notes:

- In case of discrepancy metric values are valid.
- All dimensions are estimates.
- EPP bit (electrodes) are considered integral part of collar #1.

3.1.2 System 2 – 8-1/2" EPP

The second set of specifications is based on scenario 2 (See Appendix A, Turkey). The (static) temperature of the reservoir at a depth of 3000 meters TVD is over 230°C. Significant losses are to be expected while drilling the reservoir section.

3.1.2.1Application and Benefits

The reservoir section in the Kizildere field is typically cased with a 7" liner instead of a casing hence CwD is no option. The 8-1/2" hole is drilled using a drill string BHA with EPP tool. Benefits:

- Longer bit runs or 'shoe-to-shoe' runs so improved durability and reliability
- Higher ROP

3.1.2.2 Bottom Hole Assembly

The following BHA setup in Table 5 comprises the essential components that will be supplemented with the selected steer unit and downhole tools, such as drill jars, accelerators, and potentially a leaking sub during a later stage of this project.

Table 5: EPP BHA – Turkey case

Current BHA sheet											
Item	**Description**	**Vendor**	**Serial Number**	**Fishing Neck**	**Stab O D**	**O D I D**	**Conn.**	**Length [m]**	**Cumulative Length [m]**	**Weight [kg]**	**Cumm. Weight [mT]**
1-a	8-1/2" EPP- bit (electrode, non-expandable)	IHC				8-1/2" 	 TBD	0.3	**0.3**	**20**	**0.0**
1-b	7" PPS - collar 1 with (sleeve) stabiliser near bottom	IHC			8.375"	7" TBD	TBD TBD	9	**9.3**	**1130**	**1.1**
2	7" PSS - collar 2 with (sleeve) stabiliser	IHC			8-1/4"	7" TBD	TBD TBD	9	**18.3**	**1130**	**2.3**
3	6-3/4" PDM -Power section - collar 3	IHC				6-3/4" NA	TBD TBD	9	**27.3**	**1022**	**3.3**
4	6-3/4" Cross-over Saver-Sub	3rd party				6-3/4" 3-3/4"	TBD 5/8" REG b	1	**19.3**	**125**	**3.4**
5	6-3/4" Bumper/shock sub	3rd party				6-3/4" 3-3/4"	5/8" REG p 5/8" REG b	5	**47.4**	**627**	**4.1**
6	6-3/4" float sub	3rd party				6-3/4" 3-3/4"	5/8" REG p 5/8" REG b	1	**28.3**	**125**	**4.2**
7	6-3/4" NMDC MWD Tool	3rd party				6-3/4" NA	5/8" REG p 5/8" REG b	8.5	**36.8**	**1067**	**5.2**
8	6-3/4" NM Pony Collar	3rd party				6-3/4" 3-3/4"	5/8" REG p 5/8" REG b	4	**40.8**	**501**	**5.7**
9	6-3/4" NM String stabilizer	3rd party			8-1/4"	6-3/4" 3-3/4"	5/8" REG p 5/8" REG b	1.6	**42.4**	**154**	**5.9**

3.1.3 System 3 – 12-1/4" EPP

Like the second tool description, the third system, based on scenario 3, aims to reach high-temperature reservoirs with typical well total depth range of 2000-2500 m MD (up to 3000 m MD).

3.1.3.1 Application and Benefits

The EPP with CwD is not an option in the reservoir section due to the perforated liner or barefoot completion hence no casing is installed. Therefore, an EPP based BHA to directional drill a 12-1/4" hole designed to withstand high temperatures is proposed to drill this reservoir section. Shallower (and cooler) 13-3/8" casing sections may be good opportunities, and these specifications will be in line with the case 1 specs. The ROP is restricted to 10 m/hr and multiple bit runs are needed due to short BHA life. Therefore, the EPP technology needs to drill with at least 10 m/hr but can create value if the bit runs will be prolonged: high reliability/durability is needed.

To enhance the capabilities and flexibility of use of future EPPs, it is highly desirable to have the ability to adjust hole sizes by simply swapping electrode heads, enabling the drilling of various hole sizes.

It is crucial to maintain continuous circulation for well control and to prevent overheating of the electronic components in the EPP BHA. The wells are relatively shallow compared to case 2, so fast turn-around is needed for failed components.

3.1.3.2 Bottom Hole Assembly

The following BHA setup comprises the essential components that will be supplemented with the selected steer unit and downhole tools, such as drill jars, accelerators, and potentially a leaking sub during a later stage of this project.

Table 6: Example of EPP based drilling assembly – Iceland case

Current BHA sheet									
Item	**Description**	**Vendor**	**Stab OD**	**OD / ID**	**Conn.**	**Length [m]**	**Cumulative Length [m]**	**Weight [kg]**	**Cumm. Weight [mT]**
1-a	12-1/4" EPP- bit (electrode, non-expandable)	IHC		12-1/4"		0.3	**0.3**	**20**	**0.0**
					TBD				
1-b	8-5/8" PPS - collar 1 with (sleeve) stabiliser near bottom	IHC	12-1/8"	8-5/8"	TBD	9	**9.3**	**1615**	**1.6**
				TBD	TBD				
2	8-5/8" PSS - collar 2 with (sleeve) stabiliser	IHC	12-1/8"	8-5/8"	TBD	9	**18.3**	**1615**	**3.3**
				TBD	TBD				
3	6-3/4" PDM -Power section - collar 3	IHC		8"	TBD	9	**27.3**	**1615**	**4.9**
				NA	TBD				
4	6-3/4" Cross-over Saver-Sub	3rd party		8"	TBD	1	**19.3**	**179**	**5.0**
				3-3/4"	6-5/8" REG box				
5	6-3/4" Bumper/shock sub	3rd party		8"	6-5/8" REG pin	5	**47.4**	**897**	**5.9**
				3-3/4"	6-5/8" REG box				
6	6-3/4" float sub	3rd party		8"	6-5/8" REG pin	1	**28.3**	**179**	**6.1**
				3-3/4"	6-5/8" REG box				
7	6-3/4" NMDC MWD Tool	3rd party		8"	6-5/8" REG pin	8.5	**36.8**	**1525**	**7.6**
				NA	6-5/8" REG box				
8	6-3/4" NM Pony Collar	3rd party		8"	6-5/8" REG pin	4	**40.8**	**718**	**8.4**
				3-3/4"	6-5/8" REG box				
9	6-3/4" NM String stabilizer	3rd party	12-1/8"	8"	6-5/8" REG pin	1.6	**42.4**	**287**	**8.7**
				3-3/4"	6-5/8" REG box				

3.1.4 Specifications

The specifications Table 7 are based on the cases described above and show the required geometric and operational limits required to operate the 3 different systems. More details including the justification of some of the chosen values can be found in Appendix E.

Table 7. Specifications for the 3 drilling tools.

		12-1/4" x 16"		**8-1/2"**		**12-1/4"**		
#	*Item*	*min.*	*max.*	*min.*	*max.*	*min.*	*max.*	*[unit]*
1	Length (per EPP item)	-	12	-	12	-	12	[m]
2	EPP collar OD (housing)	-	244.5	-	177.8	-	219.1	[mm]
3	EPP collar ID (annular-internal diff pressure housing)	-	226.6	-	164.0	-	198.8	[mm]
4	EPP collar Nominal Wall Thickness (Housing)	8.94	-	6.91	-	10.16	-	[mm]
5	EPP collar colaps pressure (Housing)	-	139.3	-	156.6	-	237.9	[bar]
6	EPP collar ID - Electronics OD (annular flow tbd)	198.5	-	198.5	-	198.5	-	[mm]
7	Electronics ID (inner flow tbd)	-	110	-	110	-	110	[mm]
8	EPP (electrode) OD	-	311.15	-	215.9	-	311.15	[mm]
9	EPP (electrode) expanded OD	406	444.5	N/A	N/A	N/A	N/A	[mm]
10	Downhole temp (Geothermal Gradient)	47.2	-	257	-	344	-	[°C]
11	Maximum required operational temperature	-	85	-	135	100	-	[°C]
12	Flow-line Temperature (returning drillig mud)	34	-	80	-	-	60	[°C]
13	Hydrostatic press (@ Drillling mud density)	211.9	-	494.4	-	309.0	-	[bar]
14	Differential pressure	60	-	60	-	60.0	-	[bar]
15	Weight On bit	-	13	-	6	-	9	[mT]
16	Revolutions per minute	20	60	20	60	20	60	[RPM}
17	Survival Torque on EPP (electrode)	-	9.5	-	3	-	9.8	[kNm]
18	Drilling mud flow rate (Nominal)	3400	-	1700	-	3600	-	[l/min]
19	Drilling mud flow rate (Short term maximum)	-	4500	-	3024	-	4725	[l/min]
20	Nominal flow velocity	6	-	6	-	6	-	[m/s]
21	Maximum short-term flow velocity	-	8	-	8	-	8	[m/s]
22	Drilling mud flow area (annular flow - Optional)	-	9400	-	4830	-	9900	[mm2]
23	Drilling mud flow area (inner flow - Optional)	9500	-	4780	-	10000	-	[mm2]
24	Target steerrate (Dogleg)	3	-	3	-	2.5	-	[deg/30m]
25	Achievable steerrate	5	-	5	-	4.5	-	[deg/30m]
26	Survival Dogleg (while rotating)	7	-	7	-	6	-	[deg/30m]
27	Inclination	60	-	22	-	30	-	[°]
28	Collar Material strength	55000	-	55000	-	55000	-	[psi]

3.2 Drilling Fluid

The drilling fluids are continuously in direct contact with the tool and electrodes. This paragraph discusses the drilling fluids as used in the 3 scenarios for the 3 different tools. All the used drilling fluids are water or water based. The exact mud details and properties are project and supplier specific.

In many countries, topholes are only allowed to be drilled with water-based fluids but may contain hydrocarbons. Most of the topholes consists of a sequence of soft clays and loose sands (see D1.1), and brackish / salty formation water, therefore an inhibitive mud system and sufficient weight to stabilize the clays is used to ensure that the borehole is in a good enough condition to install the casing. CwD reduces the open-hole time and therefore the wellbore stability requirements can be reduced i.e. the mud weight and inhibition can be reduced what leads to lower mud costs but also to lower mud & cutting disposal costs. The salinity could also be reduced to lower the mud conductivity and to improve the EPP drilling mechanism.

The Turkish and Icelandic cases are deeper and due to the high losses a (low-cost) WBM or just water is used to drill the (reservoir) section. OBM is too expensive to lose. Lost Circulation Material (LCM) such as mica flakes, may be used but (fresh) water will be used when total loses occur.

Table 8: General drilling fluid properties of the 3 cases

	Netherlands	**Turkey**	**Iceland**	
Name / type	KCl Glydrill (polyglycol)	Su-Polimer / Hot Drill	water	
Formation	Northsea group (sands&clays)		Crystalline basalt - Hyaloclastite	
Plastic Viscosity	ALAP	14-16		[cp]
Yield Point	15 - 25	20		[lbs/100 ft^2]
Funnel Viscosity			42-45	[sec/l]
pH	8.5 - 9.5	9.5	7-8	
Mud Weight	1.15 - 1.25	1.12-1.15	1.0 - 1.05	[SG]
6 RPM	15 [DR]	8 [lbs/100 ft2]		
K+	95000 - 135000	40-48		[mg/l]
Methylene Blue test (MBT)	<60	11.25-12.5		[kg/m^3]
API Fluid Loss	<400 [mg/l]	6.8 - 9.8 [cc/30min]	550 [cc/30min]	
Glydrill MC	2-4			[% v/v]
Chlorides	92000 - 140000	2400 - 2500		[mg/l]
NaCl	0.05 - 1.84	0.05 - 1.84		[%vol/kg/m^3]
Solids	10-15		0 - 0.5	[%vol]
Sand	<2			[%vol]

3.3 Reliability

Reliability, and durability, will depend on tool design parameters (dimensions, materials, etc.) and environmental parameters and usage (temperature, shocks, bending, etc.). However, due to the absence of detailed EPP drilling data, an initial worst-case estimate is used based on activity requirements. Case 2 (Turkey) is the most demanding in terms of run duration and is therefore used to derive a reliability target. The case requires >360 hours of drilling if the same ROP is achieved so for an 50% ROP improvement i.e., from 2.7 m/hr to 4.1 m/hr, this will be ~240 hours.

Statistics including '*bath tube*' theories on product reliability can be used but a simple approach is to take a multiple of the required run length to determine mean time between failures (MTBF). The MTBF is calculated by dividing the total operating time by the total number of failures.

The numbers above show the importance of increasing ROP; the required MTBF will decrease accordingly.

For now, MTBF target is set 10x 240hr = 2400 hrs with a maximum run length of 260 hours. This number is proposed for all tool sizes.

Reliability is only relevant if the equipment is used as per intended use and within its operating limits. Although the direct relevant parameters are listed above, it is common to list also parameters that are considered out-of-specifications. These out-of-specifications are typically part of the commercial agreement with the clients and should also be respected in field trials. A generic list can be found in Appendix C.

3.4 Techno-economic benefits

An assessment of the financial benefits has been made for the cases described in Appendix A. The results can be used to identify where the system generates the most value and guide the commercial and technical focus. More work will be needed if accurate cost benefits are required. The techno-economic assessment can be found in Appendix B.

In short the outcome for the 3 scenarios:

1. The analysis for case 1 demonstrates the benefits of Casing while Drilling in tophole sections of which EPP technology can be an enabler. The estimated time savings on the installation of a tophole casing is 28% for the used case what translates to an estimated cost saving of about € 226k (or 17% of the time-based costs).
2. The case 2 analysis investigated the relevance of drilling rate increase versus reliability improvement. The conclusion is that an ROP increment is more beneficial than a reliability improvement hence the development and commercial focus should be on materializing high ROP's. Obviously without a major reliability drop.
3. The case 3 analysis is constrained in terms of ROP. So, any benefit needs to come from longer runs hence improved reliability. A 1.5-day time savings is expected by saving on bit trips.

To conclude, reliability needs to be reasonable in the envisioned high temperature environments but drilling performance will be the differentiator with conventional technology. The drilling performance can be further leveraged with added CwD functionality.

4 Conclusion

Electro Pulsed Power (EPP) is a promising technology to boost (geothermal) drilling in many different applications around the world. Introducing novel drilling technology is always a challenge due to the extreme operational environment and this document bridges the gap between real-life drilling and the EPP tool developers by providing not only specifications but also additional design considerations and explanations.

Three different sets of tool specifications and requirements for directional EPP tools have been delivered based on three real applications in the Netherlands, Turkey, and Iceland. The 3 sets cover the globally most used hole sizes namely, 8-1/2" and 12-1/4" hole setups. Additionally, a 13-3/8" Casing while Drilling (CwD) system has been specified using a 12-1/4" x 16" expandable or bi-center EPP electrode configuration aka 12-1/4" x 16" EPP bit. EPP and CwD technology may be synergistic: EPP can enable the CwD promise and its specific benefits while CwD may also provide some benefits to EPP. Various additional design considerations have been included briefly to bridge the gap between the Research & Development environment and operations on drilling rigs.

An economical comparison between the current scenarios is made to further guide and prioritize the development direction. From this benchmark study the Turkish 8-1/2" application seems the most interesting providing the expected drilling rate improvement materializes and reliability or durability reaches commercial levels.

5 References

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Appendix A. Scenario selection

Deeplight deliverable D1.1 listed a series of potential EPP applications gathered by the consortium partners. Although all scenarios may be applicable and realistic at a given time, some criteria are applied to ensure that the most beneficial cases are used:

- Well sections using (primarily) liners will not be considered for casing while drilling applications because this requires more advanced liner hanger systems.
- Soft formations where hole cleaning is the limit of the achievable drilling rate are taken out as initial opportunities because the limiting factor is not bit related. However, directional top-hole sections drilled using casing while drilling (CwD) is considered because the cutting method, e.g. underreamer, is often the limiting factor in drilling performance and/or reliability.
- Deep applications in hard formations are preferred over shallow.

The list with collected scenarios and the final selection as per above stated criteria can be found Table 9. Only the remaining 3 scenarios have been used to build the tool specifications.

Table 9. Collected scenarios as per DEEPLIGHT D1.1

#	Country	Scenarios	Bit size (in)	Comment	Case #
~~1~~	~~NL~~	~~Standard geothermal well (from conductor to TD)~~	~~16 \ 12.25 \ 8.5~~	~~PDC is performing very well here so no direct competitive advantage.~~	
~~2~~	~~NL~~	~~CwD to drill deep hole section (Kolenkalk Gr.)~~	~~8.5 x 6~~	~~Adapted size to correct dimensions. Same case as above but combined with casing drilling to overcome installation problems.~~	
~~3~~	~~NL~~	~~Very (Ultra) deep wells (deep into the (Kolenkalk Gr.)~~	~~12.25 \ 8.5~~	~~Feasibility of Dutch UDG wells are still under investigation. Good opportunity but timing unclear.~~	
4	NL	CwD to drill top hole section (North Sea Gr.)	12.25 x 16	Soft and diverse formations, thus difficult to improve performance. CwD may make a difference by reducing risk.	1
5	Tk	Fm. Menderes (complex of metamorphic rocks)	8.5	Long and deep sections in varies hard (fractured) formations drilled with low ROP. EPP is a good opportunity to save time due to higher ROP and less bit trips. Liner required so CwD not an option, just EPP.	2
6	Is	Crystalline basalt\Hyaloclastite (volcanic Island complexes)	12.25	Very hard, hot, and fractured reservoir. Slotted liner, so just EPP. *Higher casing section may be an EPP-CWD option i.e. similar to case 1.*	3
~~7~~	~~Is~~	~~Crystalline basalt\Hyaloclastite (volcanic Island complexes)~~	~~12.25~~	~~Variation on scenario 6~~	

Selected Case Scenarios overview

From above, three cases are used as inputs to define EPP(-CwD) functional requirements and specifications.

Table 10. Collected case as per DEEPLIGHT D1.1 and used as input for tool specifications.

Country	Scenarios	Bit size (in)	Comment	Case #
Netherlands	CwD to drill top hole section (North Sea Gr.)	12.25 x 16	Soft and diverse formations, thus difficult to improve performance. CwD may make a difference by reducing risk.	1
Turkey	Fm. Menderes (complex of metamorphic rocks)	8.5	Long and deep sections in varies hard (fractured) formations drilled with low ROP. EPP is a good opportunity to save time due to higher ROP and less bit trips. Liner required so CwD not an option, just EPP.	2
Iceland	Crystalline basalt\Hyaloclastite (volcanic Island complexes)	12.25	Very hard, hot, and fractured reservoir. Slotted liner, so just EPP. *Higher casing section may be an EPP-CWD option i.e. similar to case 1.*	3

Case 1 – Top Hole CwD - Netherlands

The first scenario is based on a great majority of wells directionally drilled in the Netherlands to secure the wells' top-hole section of typically 1000 m to 1200 m deep. It is important to note that the directional drilled wellbore will pass through different sedimentary rock types, which are generally easily drilled with conventional Polycrystalline Diamond Compact (PDC) bits, while the hole cleaning and cutting handling limits the maximum ROP. In contrary, in CwD the limiting factor is not the bit but the underreamer or bit – underreamer interaction. The reason in the latter case is due to different mechanical interaction with the formations which may result in poor drilling performance, vibrations, or complicated drilling assemblies. An EPP version of a combined bit and under-reamer may unlock casing while drilling promises.

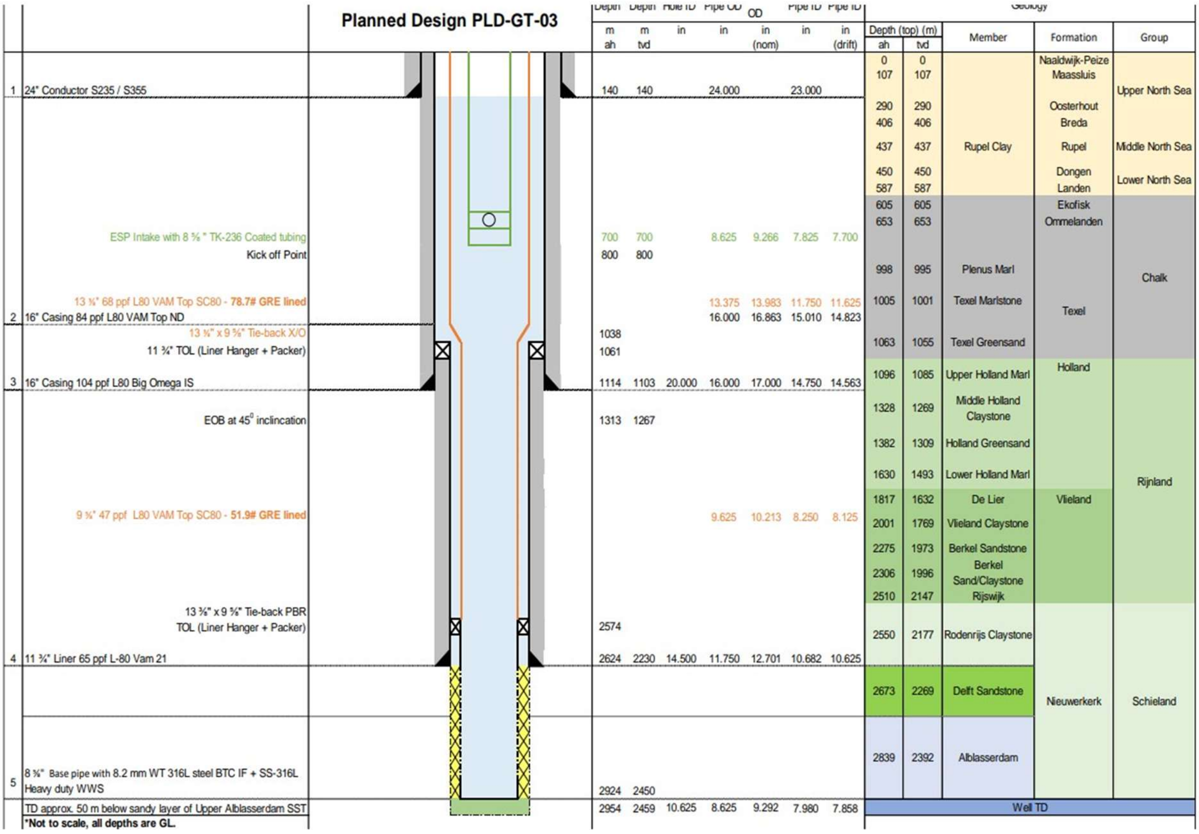

Figure 20. Typical example of Dutch geothermal producer well with the 1st casing (16in in this case) set around 1100 m deep.

As visible in Figure 20, liners are used for the deeper sections to create space for the ESP and tie-back that requires a monitorable annulus. Liners are currently not considered as option for CwD, hence only applies for the top hole.

Case 2 – Drilling of Menderes Formation - Turkey

The second scenario is based on the geological setting and drilling complexities found in the Fm. Menderes (complex of metamorphic rocks) of the Kizildere field in Turkey. Drilling through hard and fractured volcanic formations is required to access the geothermal reservoir. The reservoir thickness is about 1000 m MD with a wellbore inclination not exceeding 25°. This section is usually drilled with an 8-½" PDC bit and cased with a 7" liner. These drilling operations typically involve drilling through hard and fractured volcanic formations required to access the geothermal reservoir. Several round trips in the last two wellbore sections (8-1/2 & 12-1/4") are needed, to change drill bits and bottom hole electronics affected by high vibrations during drilling. In this case, only 8-1/2" is considered. The (static) temperature of the reservoir at a depth of 3000 meters TVD is over 230°C. Significant losses are to be expected while drilling the reservoir section.

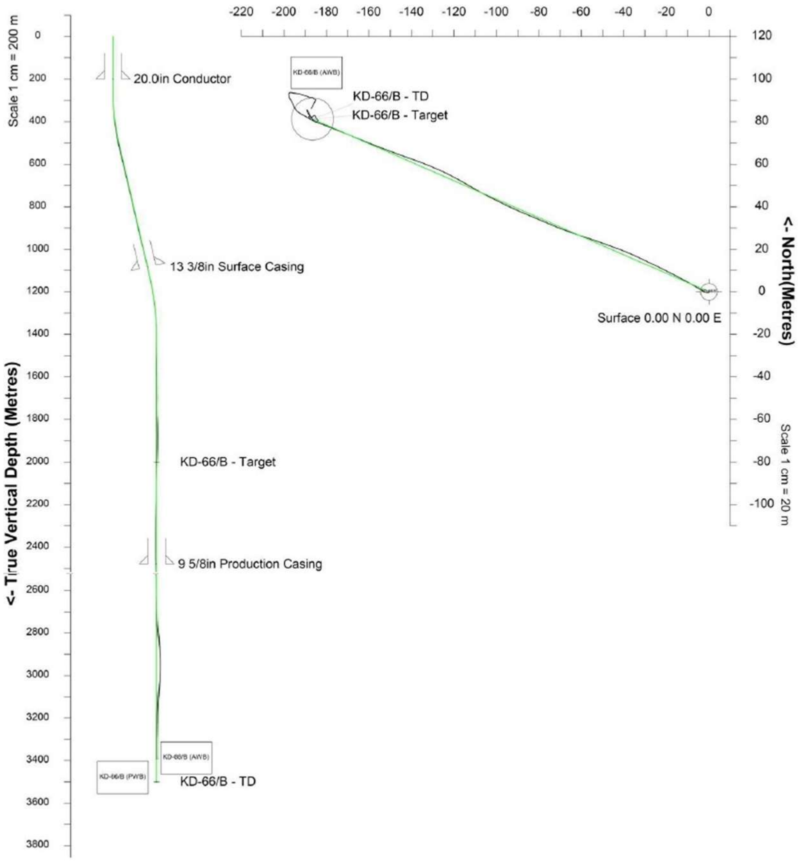

Figure 21. Example of Turkish geothermal well.

Case 3 – High temperature wells Iceland

Like the second scenario, the third scenario aims to reach high-temperature reservoirs with typical well total depth range of 2000-2500 m MD (up to 3000 m MD). The reservoir sections are fracture dominated and are mainly constituted by altered basalts of the Crystalline basalts and Hyaloclastite members. The experience indicates that during drilling operations near stuck pipes incidents and afterwards, during trips out of the hole, loss of circulation events occurs. The J-type wellbore geometry is widely employed, i.e. a vertical section, a build section, and a tangent section. Reservoir sections up to 1000 m MD in lengths are to be drilled. Casing programs are normally of two sizes, i.e. "regular" with 9 5/8" production casing and 8½" hole for the production section or "wide/large" with 13 3/8" production casing and 12¼" hole. In turn, a 7" or 9-5/8" perforated liner is used in the production section for support and to prevent hole collapse, but in rare cases where suitable the section is left barefoot without a liner. In case of total losses within the reservoir section, drilling operations continue replacing drilling fluid from water-based mud with water; part of the cuttings are forced into geological faults or fractured formations. Various ROP values have been reported. However, 10 m/hr is required by regulatory authorities in Iceland to avoid hole-cleaning issues [4].

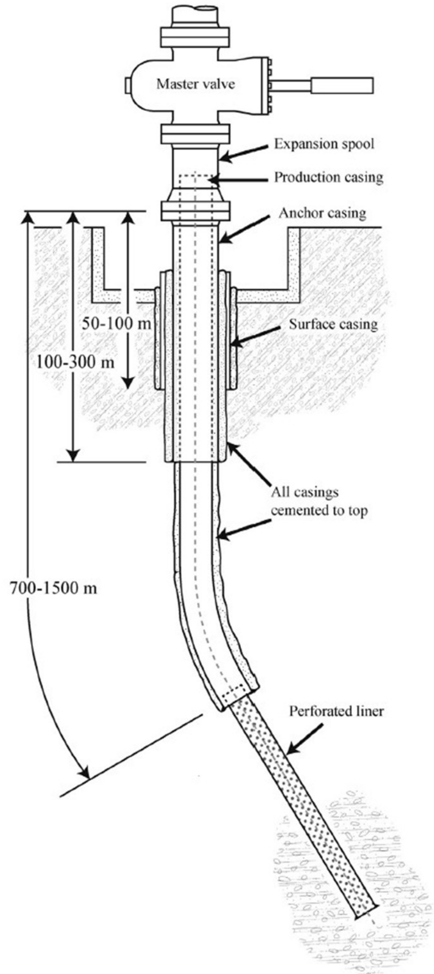

Figure 22. Sketch of a typical geothermal well in Iceland. EPP is considered for the deepest well section. Although, the shallower section is an option for EPP-CwD application.

Appendix B. Techno-Economical assessment

This Appendix will evaluate the economic benefits of the in Appendix A described and defined cases. The system for each case is compared with a conventional drilling system in that application. Time savings are eminent and the most important time aspects are the reduction of tripping casing & drill pipe and increasing the ROP. Relevant data is available but still several assumptions had to be made. The most determining are tripping times, the following numbers are used:

- Cased hole tripping with Drill Pipe 300 m/hr
- Open hole tripping with Drill Pipe 200 m/hr
- Casing Running 75 m/hr

Case 1

In the first scenario, the assumed case is the application of EPP technology along with Casing while Drilling (CwD) Level 3 (steering available). This setup has several benefits that have been investigated in the cost benefit estimate:

- Energy saving due to lower pump power for hole cleaning
- Casing is already in place, no time spent on pipe run – just a cased hole run to retrieve BHA.
- Less time to be spent on check trips, hole conditioning, hole cleaning at connection etc.
- In general, less NPT because of reduced formation dependency; 15% -> 5% used for contingency.
- Simpler mud system with less chlorine/salt which is cheaper and cheaper to dispose off.

The maximum ROP is limited by hole cleaning (cutting handling), so an EPP benefit related to an increased (on-bottom) ROP is not possible. Also, more costs are expected on tubular running services as the casing handling will take longer and more cost on cutting handling/processing due to the lower spec mud system.

The detailed cost estimate of a recently drilled well (MDM-GT-10) has been used to finalise this case study.

Table 11: Cost items assumptions

Description	**motivation**	
Rig + energy	1500	euro/day saving on energy
Directional Drilling - EPP +MWD		considered the same per day
Cutting & Fluids disposal (low chlorine)	20%	saving due to low Chlorine
Drilling Fluids (reduced additives for fluid loss, inhibition (KCl))	20%	saving on additives
Mudlogging		lower due to less days
Tubular Running Services		more needed during drilling days
Solid control - Shaker & screens inspections	20%	increase
Onsite Security		lower due to less days

Time steps and estimations

Table 12: Time steps for conventional drilled top-hole

Original plan for Top hole section						
	Depth (m MD)	Section length (m)	Duration (hrs)	Duration (days)	Cumm. (days)	including 15% NPT
Clean out conductor to 120 m and POOH	120	20	15.0	0.6	1	0.7
M/U BHA#2 and Drill to 1317 m	1317	1197	152.6	6.4	7	8.0
Circulate hole clean & POOH, L/D BHA	1317		24.0	1.0	8	9.2
Run and cement casing	1317		60.0	2.5	10	**12.1**

Table 13: Time steps for EPP-CwD drilled top-hole.

Plan for Top hole section with EPP						
	Depth (m MD)	Section length (m)	Duration (hrs)	Duration (days)	Cumm. (days)	including 5% NPT
M/U BHA#1;	120	20	0.0	0.0	0	0.0
Drill conductor 16" hole to 1317 m	1317	1317	167.6	7.0	7	7.3
Retrieve, POOH, L/D BHA	1317		10.8	0.4	7	7.8
Cement casing	1317		20.0	0.8	8	**8.7**

1. It is stated above, that no on-bottom ROP increase is expected since the limiting factor is not the bit, but the cutting handling at the rig.
2. Time consuming steps have been improved: Casing running is limited by ROP and BHA retrievable only done inside casing.
3. A significant time reduction, however, is expected when POOH of the drilling assembly where no open hole operations are needed. However, further improvement can be done by retrieving the relative light BHA by wireline and/or pressure.
4. The short BHA is also used to drill out conductor to save 1 trip.
5. In general, 5% NPT is used instead of 15% due to the reduced formation dependency and less steps in general.

Added/saved cost

Table 14: Cost estimate for the conventional drilling system

Cost elements - conventional drilling			
Description	**Unit**	**Unit(s) estimated**	**Total cost**
Rig + energy	days	12	€ 556,740
Directional Drilling - PDM+MWD	days	12	€ 293,897
Cutting & Fluids disposal (high chlorine)	MT	2000	€ 300,000
Drilling Fluids	Job	1	€ 100,000
Mudlogging	day	12	€ 25,912
Tubular Running Services	day	8	€ 67,600
Solid control - Shaker & screens inspections	well	10	€ 754
Onsite Security	day	12	€ 12,070
			€ 1,356,972

Table 15: Cost estimate for EPP-CwD drilling system.

Cost elements - EPP-CwD drilling			
Description	**Unit**	**Unit(s) estimated**	**Total cost**
Rig + energy	days	9	€ 452,546
Directional Drilling - EPP +MWD	days	9	€ 276,337
Cutting & Fluids disposal (low chlorine)	MT	2000	€ 240,000
Drilling Fluids (reduced additives for fluid loss, inhibition (KCl))	Job	1	€ 80,000
Mudlogging	day	9	€ 20,475
Tubular Running Services	day	7	€ 59,653
Solid control - Shaker & screens inspections	well	13	€ 1,170
Onsite Security	day	9	€ 8,689
			€ 1,138,870

Final savings:

- Cost saving € 226,102
- Cost saving 17%
- Time saving [days] 3.4 days
- Time saving 28%

Case 2

In this scenario, the main problem is the hardness of the rock and the downhole temperature. These two factors lead to several runs to replace the bit and/or electric components in the BHA.

The data used to calculate these cost savings has been provided by Zorlu Enerji, and displayed in USD instead of EUR.

Assumptions

- Rig Spread rate 22700 $/day
- Tripping speed Open Hole 200 m/hr
- Tripping speed Cased Hole 300 m/hr
- Time to change a bit 2 hr
- 12 1/4" casing setting depth 2464 m
- 8 1/2" casing setting depth 3447 m
- Current ROP 2.7 m/hr
- Current # bit runs 5
- No further cost compared to conventional drilling assemblies.
- Same energy usage per day

These following scenarios have been investigated:

- A more reliable EPP system that can drill longer intervals than the conventional/benchmark BHA. As there is minimal mechanical interaction, temperature is expected to be a major negative impact on the reliability of the system. Mud circulation is required for cooling hence less tripping will also result in less time that for the BHA spent in an uncooled hot environment.
- Higher ROP's because the EPP works against the tensile strength of the rock, while conventional rotary drilling does the same against the compressive strength of the rock. The tensile strength of rocks is usually very small and is of the order of 0.1 times the compressive strength. This presumably results in a significant increase in ROP, especially in the case of hard rocks.

Table 16: Investigated scenarios.

	Benchmark / Current	High Reliability / Same ROP	High Reliability / Lower ROP	High Reliability / High ROP	Same Reliability / Very High ROP	Same Reliability / High ROP
ROP	2.7	2.7	2.2 (-20%)	4.1 (+50%)	5.4 (+100%)	4.1 (+50%)
# bit runs	5	1	1	1	5	5
Time saved [hr]	0	93.4	2.4	214.7	182.1	121.4
Money saved	$ -	$ 88,309	$ 2,221	$ 203,094	$ 172,177	$ 114,784

The results show that especially an ROP increment will give favourable results.

Case 3

The primary benefit of EPP in this (Iceland) scenario is, the lack of wear and the resulting BHA trips. During drilling a 1422 m long section, the crew had made a trip to replace the bit. This operation took them 36 hours. The expected cost saving is coming from reduced rig time, and savings on motor rentals, bits and logistics. In this case, the maximum ROP was limited to 10 m/hr by the client, so the benefit from increased available ROP does not play a role.

Assumptions

- The entire section can be drilled with one EPP head.
- No need for bit trip(s)

Time steps and estimations

Based on the data received from Iceland Drilling, it can be assumed that 36 hours could be saved in this scenario by using EPP.

Saved cost

Time-dependent saved costs:

- Rig daily cost
- Energy cost
- Directional Driller daily cost
- Mud logger daily cost
- Fluids Engineer daily cost
- Drilling Supervisor daily cost
- Other rig-related daily costs

One-time saved costs:

- Additional bit rental
- Additional motor rental

Comparison

Since there is no up-to-date data on the above-mentioned costs, it cannot be accurately stated how much the use of EPP technology would save in this scenario. However, to quantify the assumed savings, the same data set will be used as in Scenario 1.

Table 17: Cost savings calculation

Description	Daily rate (€/day)	Multiplier (days saved)	Cost saved (€)
Rig cost	23.440	1.5	35.160
Directional Driller	5200		7800
Mudlogging	1610		2415
Tubular running service	7825		11.737
Onsite Security	1001		1501
Total			58.613

In case the EPP could save 1.5 operational days by saving the bit trip discussed above, **58.613 €** saving is expected.

Appendix C. Generic 'out-of-specifications'

To limit the use, or define abuse, of drilling tools several 'out-of-specifications' conditions are listed in this Appendix. The used values are in line with current drilling tools and may require adapting to EPP capabilities.

Drilling Fluid

OBM will likely require modifications to any elastomer elements in the system such as seals or power section stator. Therefore, and because all cases are using Water Based Muds (WBM), due to high losses experienced or shallow formations drilled, Oil Based Muds (OBM) can be considered out of specification. The same applies to Sodium Silicate and Lamium drilling fluids.

Table 18: Chloride Content

Chloride Content	
< 20.000 mg/liter	Minimal effect on the tools
20.000 – 56.000 mg/liter	Extra care must be taken when pulling out of the hole
>56.000 mg/liter	When the chloride levels exceed 56,000 mg/liter, corrosion of common equipment material can be severe, even in the downhole environment. It is therefore advised to use corrosion inhibitors and put special attention to the pH-control of the drilling fluid to maintain the pH between 10 and 12 when chloride levels are expected to exceed 56,000 mg/liter.

Table 19: Gas in Mud

Gas in mud	
Hydrogen sulfide (H_2S)	Out of specification
Nitrogen (N_2)	Out of specification
Carbon dioxide (CO_2)	Out of specification

Table 20: pH limits per Mud Type

Mud type	
Water based muds	9.0 – 12.5
Freshwater mud system	8.0 – 9.0

** The operation of tools in water base mud below pH 9.0 or above pH 12.5 is considered out of specification.*
***oil-based mud is considered out of specification.*

Table 21: Allowable sand content limits

Sand Content	
>1 %	Out of specifications
0.5 – 1 %	Solids should be controlled
<0.5 %	Recommended

The maximum concentration Lost Circulation Material (LCM) will need to be tested. Typical maximum value is 114 kg/m3 (40 lb/bbl). Operating equipment under the presence of debris / foreign objects in the mud system is considered Out of Specifications operation. A few examples are cloth, broken bolts, rust from old pipes and hand tools.

It is to follow established industry practices and provide adequate solids control equipment and treatments to control the concentration of Low Gravity Solids. The presence of abnormal levels of abrasive materials is evidence of being out of specification. When more than normal erosion is noted after stripping down in the local workshop, an out-of-specification claim will be submitted.

Shocks & Vibration limits

Shock and vibrations limits are always part of equipment specifications of tools that contain electronics. Often stick-slip values, basically the variation on pipe rotation, are included because they are often the source of vibrations. MWD tools often provide this data in real time so that drilling parameters can be adjusted. Other tools measure and log the data themselves for later analysis and/or pass the data in real time to surface by communicating via the MWD tool. The EPP tool should at least be able to record and register such data. All shock, vibration and stick-slip data as shown in the two tables in this paragraph are tool (and size) specific hence (destructive) testing may be required to determine the right levels for EPP equipment.

Table 22: Example of Stick-Slip Level definitions

Severity Level	0	1	2	3
R1; R2 Time Limit	0.0 ≤ R1 < 0.2	0.2 ≤ R1 < 0.4	1.2 ≤ R1 5 hrs	R2 > 0.1 1 hr

*R1 = (max rpm - min rpm) / (2 * average rpm)*

R2 = a measure of negative rpm time in percent (1,0 meaning 100%)

Table 23: Shock Risk

Shock Risk	Risk Level	Shocks per minute
0	No Risk	< 30 (<0,5 counts per second or cps)
1	Low Risk	30 to 300 (0,5 to 5 cps)
2	Medium Risk	300 to 3000 (5 to 50 cps)
3	High Risk	> 3000 (50+ cps)

Appendix D. Rig Site & Floor Handling

Assembly, Testing, and Transportation of EPP Tool

- Done in controlled workshop by trained technicians using proper equipment.
- Before being transported to the rig site, the EPP tool electronics must undergo an outgoing system test to ensure proper functioning. Inspections of collars and mechanical assemblies need to be done.
- While transporting the modules to the rig site's tool racks, placing and keeping pin and box thread protectors on them is necessary. These protectors must remain accessible for inspection to check for possible damage. Lift subs could be installed instead of protectors.
- Equipment with odd dimensions e.g., EPP electrodes, will require specialized packaging.
- Flatback trucks are generally used for transportation of collars/tools, auxiliary equipment, storage containers etc. to the rig site.

Figure 23. Example of drilling equipment transport.

Prior drilling on site

After receiving and offloading the EPP components, it will be stored on site until needed. Simple checks to the tool are possible.

Making Up BHA

- Tool will be transported around the rig using a crane or forklift so thread/connection protection on both sides of the collars including electrodes need to be installed.
- When the collars are positioned on the catwalk and ready to be lifted through the V-door by crane, attach a lifting sub to enable connection to the drilling rig's hoisting system. Ensure the lifting sub fits correctly and is clean.
- Before making up one collar into another, apply the appropriate dope (copper or zinc-based) to the thread and shoulders. Don't damage the thread or shoulder while stabbing the pin into the box.

- The tool will be lowered through the rig floor into the slips.
- A safety clamp (dog collar) is used in the event of a slip failure.
- Once the crew completes a connection, they can lower the collar into the hole and attach another one.
- A Shallow Hole Test is often executed to test equipment due to safety reasons that should not be done with the EPP tool above a certain depth – if advisable at all.

Note: the pictures and described steps are based on threaded connections. A straight stab connection may be required to enable proper (internal) electrical or mechanical connections between the EPP modules.

Figure 24. Drill collar in rotary table slips with safety collar on top.

Figure 25. Two Drill Collars made up. Note that alignment is difficult, and the environment is not dry/clean [5].

Appendix E. Specifications

Table 24: Specifications for system 1.

Casing while drilling + EPP
Top Hole in The Netherlands - 12-1/4" EPP + Expanded OD (13-3/8" casing)

EPP Specifications

#	Summary	min.	max.	[unit]	comment/justification
1	Length (per EPP item)	-	12	[m]	Max length that can be transported by truck and handled by most rigs
2	EPP collar OD (housing)	-	244.5	[mm]	Largest 'Standard' OD (9.5") in line with rig handling equipment
3	EPP collar ID (annular-internal diff pressure housing onl	-	226.6	[mm]	Depends on diff. Pressure, OD and material strength (see VAM TOP data sheet API 5CT)
4	EPP collar Nominal Wall Thickness (Housing)	8.94	-	[mm]	See VAM TOP data sheet API 5CT
5	EPP collar colaps pressure (Housing)	-	139.3	[bar]	See VAM TOP data sheet API 5CT
6	EPP collar ID - Electronics OD (annular flow tbd)	198.5	-	[mm]	Electronics OD depends on configuration and flow area - tbd
7	Electronics ID (inner flow tbd)	-	110	[mm]	Electronics ID depends on configuration and flow area - tbd
8	EPP (electrode) OD	-	311.15	[mm]	Un-expanded, tool-pass-through size (12.25") or casing ID
9	EPP (electrode) expanded OD	406	444.5	[mm]	Required hole size for casing to pass through
10	Downhole temp (Geothermal Gradient)	47.2	-	[°C]	@ 1200 m TVD x 3.1°C/100m + 10°C
11	Maximum required operational temperature	-	85	[°C]	Based on real-time MWD data (~1.7 times the measured temperature of the bottom hole section)
12	Flow-line Temperature (returning drillig mud temperatur	34	-	[°C]	@ 1200 m TVD
13	Hydrostatic press (@ Drillling mud density)	211.9	-	[bar]	@ 1200 m TVD (1.2 S.G) x 1.5SF
14	Differential pressure	60	-	[bar]	(bit pressure drop - assumed 40bar in case of balling/plugging) x 1.5
15	Weight On bit	-	13	[mT]	Weight below bumper sub 8.8mT x 1.5 SF
16	Revolutions per minute	20	60	[RPM}	Minimum due to continous rotation; max for hole cleaning in inclined hole; will depend on WP4
17	Survival Torque on EPP (electrode)	-	9.5	[kNm]	Assumed 6.5 k Nm as measurable by driller x 1.5SF (see Appendix B)
18	Drilling mud flow rate (Nominal)	3400	-	[l/min]	In line with mud rising annular velocity opposite drill pipes (VA) and Nominal ECI specs for 13-3/8" casing
19	Drilling mud flow rate (Short term maximum)	-	4500	[l/min]	Max in line with SLB MWD Technologies
20	Nominal flow velocity	6	-	[m/s]	6 m/s (API 14E).
21	Maximum short-term flow velocity	-	8	[m/s]	8 m/s for short term rates (SLB MWD Technologies)
22	Drilling mud flow area (annular flow - Optional)	-	9400	[mm2]	See TFA calculation
23	Drilling mud flow area (inner flow - Optional)	9500	-	[mm2]	See TFA calculation
24	Target steerrate (Dogleg)	3	-	[deg/30m]	Planned/nominal buildrate
25	Achievable steerrate	5	-	[deg/30m]	Achievable steerrate to be able to correct
26	Survival Dogleg (while rotating)	7	-	[deg/30m]	Dogleg that can be reamed back through
27	Inclination	60	-	[°]	As per scenario requirement
28	Collar Material strength	55000	-	[psi]	Used for wallthickness determination out of pressure differential (Grade: J55)

Table 25: Specifications for system 2

Conventional drilling string + EPP
Reservoir section in Turkey_8-1/2" EPP-Electrode (9-5/8" casing)

EPP Specifications

#	Summary	min.	max.	[unit]	comment/justification
1	Length (per EPP item)	-	12	[m]	Max length that can be transported by truck and handled by most rigs
2	EPP collar OD (housing)	-	177.8	[mm]	In line with rig handling equipment
3	EPP collar ID (annular-internal diff pressure housing only)	-	164.0	[mm]	Depends on diff. Pressure, OD and material strength (see DINO VAM data sheet API 5CT)
4	EPP collar Nominal Wall Thickness (Housing)	6.91	-	[mm]	see VAM TOP data sheet API 5CT
5	EPP collar colaps pressure (Housing)	-	156.6	[bar]	see VAM TOP data sheet API 5CT
6	EPP collar ID - Electronics OD (annular flow tbd)	198.5	-	[mm]	Electronics OD depends on configuration and flow area - tbd
7	Electronics ID (inner flow tbd)	-	110	[mm]	Electronics ID depends on configuration and flow area - tbd
8	EPP (electrode) OD	-	215.9	[mm]	
9	EPP (electrode) expanded OD	N/A	N/A	[mm]	
10	Downhole temp (Geothermal Gradient)	257	-	[°C]	@ 3000 m TVD x 7.9°C/100m + 20°C
11	Maximum required operational temperature	-	135	[°C]	Based on real-time MWD data (~1.7 times the measured temperature of the bottom hole section)
12	Flow-line Temperature (returning drillig mud temperature)	80	-	[°C]	@ 3000 m TVD
13	Hydrostatic press (@ Drillling mud density)	494.4	-	[bar]	@ 3000 m TVD (1.12 S.G) x 1.5SF
14	Differential pressure	60	-	[bar]	(bit pressure drop - assumed 40bar in case of balling/plugging) x 1.5
15	Weight On bit	-	6	[mT]	Weight below bumper sub 4.1mT x 1.5 SF (see BHA)
16	Upward/Downward Jarring	-	NA	[kN]	Jarring may not lead to junk in hole. EPP must withstand high load and impact needed during the freeing operation
17	Absolute Overpull	-	NA	[kN]	Overpull may not lead to junk in hole
18	Revolutions per minute	20	60	[RPM}	minimum due to continous rotation; max for hole cleaning in inclined hole
19	Survival Torque on EPP (electrode)	-	3	[kNm]	Assumed 2 k Nm as measurable by driller x 1.5SF (see Appendix B)
20	Drilling mud flow rate (Nominal)	1700	-	[l/min]	In line with mud rising annular velocity opposite drill pipes (VA)
21	Drilling mud flow rate (Short term maximum)	-	3024	[l/min]	Max in line with SLB MWD Technologies
22	Nominal flow velocity	6	-	[m/s]	6 m/s (API 14E).
23	Maximum short-term flow velocity	-	8	[m/s]	8 m/s for short term rates (SLB MWD Technologies)
24	Drilling mud flow area (annular flow - Optional)	-	4830	[mm2]	See TFA calculation
25	Drilling mud flow area (inner flow - Optional)	4780	-	[mm2]	See TFA calculation
26	Target steerrate (Dogleg)	3	-	[deg/30m]	Planned/nominal buildrate
27	Achievable steerrate	5	-	[deg/30m]	Achievable steerrate to be able to correct
28	Survival Dogleg (while rotating)	7	-	[deg/30m]	Dogleg that can be reamed back through
29	Inclination	22	-	[°]	S-shaped wells
30	Collar Material strength	55000	-	[psi]	Used for wallthickness determination out of pressure differential (Grade: J55)

Table 26. Specifications for system 3

Scenario 3
Conventional drilling string + EPP
Reservoir section in Iceland_12-1/4" EPP-Electrode (9-5/8" casing)

EPP Specifications

#	Summary	min.	max.	[unit]	comment/justification
1	Length (per EPP item)	-	12	[m]	Max length that can be transported by truck and handled by most rigs
2	EPP collar OD (housing)	-	219.1	[mm]	Largest 'Standard' OD (9.5") hence in line with rig handling equipment
3	EPP collar ID (annular-internal diff pressure housing only)	-	198.8	[mm]	Depends on diff. Pressure, OD and material strength (see VAM TOP data sheet API 5CT)
4	EPP collar Nominal Wall Thickness (Housing)	10.16	-	[mm]	See VAM TOP data sheet API 5CT
5	EPP collar colaps pressure (Housing)	-	237.9	[bar]	See VAM TOP data sheet API 5CT
6	EPP collar ID - Electronics OD (annular flow tbd)	198.5	-	[mm]	Electronics OD depends on configuration and flow area - tbd
7	Electronics ID (inner flow tbd)	-	110	[mm]	Electronics ID depends on configuration and flow area - tbd
8	EPP (electrode) OD	-	311.15	[mm]	
9	EPP (electrode) expanded OD	N/A	N/A	[mm]	
10	Downhole temp (Geothermal Gradient)	344	-	[°C]	@ 2000 m TVD x 17°C/100m + 4°C
11	Maximum required operational temperature	100	-	[°C]	Based on real-time MWD data (~1.7 times the measured temperature of the bottom hole section)
12	Flow-line Temperature (returning drillig mud temperature	-	60	[°C]	Partial to total losses are expected
13	Hydrostatic press (@ Drillling mud density)	309.0	-	[bar]	@ 2000 m TVD (1.05 S.G) x 1.5SF
14	Differential pressure	60.0	-	[bar]	(bit pressure drop - assumed 40bar in case of balling/plugging) x 1.5 _ Note: depth of total losses must be consider
15	Weight On bit	-	9	[mT]	Weight below bumper sub 5.9mT x 1.5 SF
16	Revolutions per minute	20	60	[RPM}	Minimum due to continous rotation; max for hole cleaning in inclined hole
17	Survival Torque on EPP (electrode)	-	9.8	[kNm]	Assumed 6.5 k Nm as measurable by driller x 1.5SF (see Appendix B)
18	Drilling mud flow rate (Nominal)	3600	-	[l/min]	In line with mud rising annular velocity opposite drill pipes (VA)
19	Drilling mud flow rate (Short term maximum)	-	4725	[l/min]	Max in line with SLB MWD Technologies
20	Nominal flow velocity	6	-	[m/s]	6 m/s (API 14E).
21	Maximum short-term flow velocity	-	8	[m/s]	8 m/s for short term rates (SLB MWD Technologies)
22	Drilling mud flow area (annular flow - Optional)	-	9900	[mm2]	See TFA calculation
23	Drilling mud flow area (inner flow - Optional)	10000	-	[mm2]	See TFA calculation
24	Target steerrate (Dogleg)	2.5	-	[deg/30m]	Planned/nominal buildrate
25	Achievable steerrate	4.5	-	[deg/30m]	Achievable steerrate to be able to correct
26	Survival Dogleg (while rotating)	6	-	[deg/30m]	Dogleg that can be reamed back through
27	Inclination	30	-	[°]	J-Shaped wells
28	Collar Material strength	55000	-	[psi]	Used for wallthickness determination out of pressure differential (Grade: J55)