Chair of Petroleum and Geothermal Energy Recovery

Master's Thesis

Hammer Drilling Technology for Geothermal Deep Drilling within the Crystalline Basement

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Kurzfassung

Hauptziel dieser Arbeit war es, einen gut strukturierten Überblick über potenzielle Technologien und Ansätze zum Erbohren geothermischer Ressourcen innerhalb des kristallinen Grundgebirges zu erarbeiten. Im Detail beschäftigt sich die Arbeit mit dem Ansatz des Hammerbohrverfahrens und den damit einhergehenden technischen sowie ökonomischen Herausforderungen. Relevante Projektdaten von einer geplanten geothermischen Erschließung im kristallinen Grundgebirge liefern die Basis für eine technische und finanzielle Betrachtung der Hydraulik- sowie Drucklufthammertechnologie im Vergleich zum konventionellen Bohrverfahren.

Gründlich recherchierte Literatur im Bezug auf die Themen, konventionelles Bohren, Spülung und Additive, sowie Technologien im speziellen Zusammenhang mit dem Lufthammerverfahren im kristallinen Grundgebirge, bilden die Basis der Arbeit. Erkenntnisse aus der Literatur Recherche sowie Experten Interviews erlaubten grundlegendes Equipment sowie benötigte Dienstleistungen in Bezug auf ein funktionsfähiges Lufthammersystem, zu erarbeiten. Benötigtes Equipment sowie Dienstleistungen bildeten die Basis für Ausschreibungsunterlagen welche es erlaubten aussagekräftige Angebote und Preise von Servicefirmen zu erhalten. Des Weiteren wurde eine Monte Carlo Simulation für die Ermittlung einer Wahrscheinlichkeitsverteilten, der den unterschiedlichen Bohrverfahren zu Grunde liegenden Projektdauer, eingesetzt. Zeitabhängige sowie zeitunabhängige Massen in Kombination mit relevanten Industriepreisen ermöglichten es eine ökonomische Analyse zum Wirtschaftlichen Vergleich der beiden Bohransätze durchzuführen.

Unter anderem bietet die Arbeit einen Überblick über modernste Konzepte und Ansätze im Zusammenhang mit Tiefbohrungen im kristallinen Grundgebirge. Weitere Ergebnisse beinhalten die Dimensionierung des Air Packages, Berechnung geeigneter Betriebsparameter des Lufthammers, sowie die Ausarbeitung des notwendigen unter Tage und ober Tage Equipments für ein funktionsfähiges Lufthammersystem. Darüber hinaus wurde ein Workflow sowie ein Tool zur Bewertung der Wirtschaftlichkeit von Hammerbohrverfahren im Vergleich zum konventionellen Bohrverfahren entwickelt. Die Ergebnisse der Analyse basieren auf aktuellen Industriepreisen sowie ausgearbeiteter zeitabhängiger sowie zeitunabhängiger Massen.

Die Arbeit bietet einen neuartigen Ansatz, um die Wirtschaftlichkeit des Lufthammerverfahrens im Vergleich zum konventionellen Bohren abschätzen zu können.

Abstract

Main goal of this study is to give a well-structured overview of potential technologies and approaches on how to drill hard and abrasive formations typically encountered when drilling for geothermal resources within the crystalline basement. The thesis will follow the percussive hammer drilling approach more closely. It will deal with a technical and financial evaluation of the hydraulic and air hammer technology compared to conventional drilling methods based on project data from a planned geothermal development.

A thoroughly researched literature review covering the topics of conventional drilling, fluid systems and additives, and hammer drilling with a special focus on air hammer drilling, all in relation to geothermal deep drilling within the crystalline basement, is presented within the thesis. Knowledge gained throughout the literature review and expert interviews allowed to elaborate necessary equipment and basic technical requirements to perform air hammer drilling within the planned project. Obtained required equipment and necessary services form the basis of air hammer related tender documents which allowed to receive informative equipment and service prices related to air hammer drilling. Furthermore, a Monte Carlo simulation is used to produce probabilistic well construction times considering the two different drilling approaches. Received prices and elaborated air hammer drilling related quantities allowed to perform an economic analysis comparing the air hammer and conventional drilling approach.

This study provides an overview of state-of-the-art concepts and approaches related to deep drilling within crystalline rocks. Other results are dimensioning of an appropriate air package, calculation of air hammer operating parameter and elaboration of suitable subsurface as well as surface components to allow for a functional air hammer drilling system. Furthermore, this study developed a tool to assess the economic viability of the hammer drilling technology compared to conventional deep geothermal drilling within the crystalline basement. The results of the performed economic analysis are based on recent industry prices and obtained time dependent and time independent quantities elaborated throughout the thesis.

The thesis provides a novel approach allowing to estimate and compare economic viability of air hammer drilling in contrast to conventional geothermal basement drilling.

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1 Introduction

Even though most commercial geothermal projects utilize hot geothermal water originating from hydrothermal reservoirs located in sedimentary basins, the utilization of geothermal resources trapped within the crystalline basement bares a considerable potential. This is mainly linked to the recent developments in the field of engineered geothermal systems (EGS) and deep borehole heat exchanger within the mentioned geological setting. The basic concept behind EGS is the creation of a hydraulically conductive system within deep hot crystalline rocks. This is achieved, amongst others, by hydraulic stimulation of the subsurface. The artificial creation of flow paths, connecting potential injector and producer wells, allow utilization of large quantities of trapped geothermal energy. The main advantage of this technology is that someone is highly independent of the local geological setting. With the EGS technology, a large deep heat exchanger can be created at locations where energy in form of heat and electricity is needed most. Establishing these types of geothermal powerplants nearby cities or large industrial complexes decrease energy transport costs and increase the efficiency and, therefore, the economic viability of such projects. Another important factor concerning the economic feasibility of deep geothermal projects within the crystalline basement is linked to the drilling cost for establishing the geothermal wells. Low rates of penetration (ROP) when applying conventional drilling methods as well as frequent necessary bit changes are yielding in long project durations and, therefore, high project costs. The required initial investment, as well as the exploration risk, are a seemingly insuperable obstacle for potential investors, ultimately leading into leaving vast amounts of potential geothermal resources untapped. Unconventional drilling methods such as air and hydraulic hammer drilling may be a promising solution.

The hammer drilling technology, as such, is not very new, but its application is becoming more popular with the recent upturn of geothermal projects throughout Europe. However, large scale commercial operation of the hammer drilling technology within deep drilling projects requires a thorough understanding of the technology, its capabilities, and limits that are currently under investigation within the geothermal sector. Many open questions need to be answered, as well as potential problems solved to access the economic viability of the hammer drilling technology within deep geothermal drilling projects. Industry data, as well as reference projects dealing with comparable circumstances regarding well design and geology, are rarely found. This thesis is built around the problem of assessing the economic viability of the air hammer technology in comparison with conventional state of the art drilling technologies. This assessment is based on project data from a planned geothermal development, in close collaboration with industry experts.

An extensive literature study concerning the current state of the art, as well as ongoing research projects, for drilling within very hard and abrasive geological formations, was conducted. A discussion of the different approaches, as well as a market research concerning commercially available technologies, is provided.

Despite a thorough introduction of different available approaches for basement drilling is given, the focus of this thesis will lie on the implementation of the hammer drilling technology. To assess and discuss opportunities as well as technical challenges, a well-structured introduction of the planned geothermal project is given. Geological circumstances, as well as the most prominent technical challenges, are presented. The project, with all relevant data, acts as a base case for all further technical and economic assessments. Technical implementation with all relevant surface and subsurface modifications of a conventional drilling rig, as well as required equipment, will be discussed regarding the project. Due to a strong industrial partner, very fruitful sources consisting of expert interviews and industry expertise, amongst others, could be tapped to establish this thesis.

The first section covers the introduction to hard rock drilling methods currently used. It provides an introduction and discussion about rotary drilling, hydraulic hammer drilling, and air hammer drilling within the crystalline basement. Particular focus is set on drilling fluid systems and respective equipment required for percussion drilling. A brief introduction to the different systems, as well as a discussion about technical challenges and solutions, are provided.

The second section elaborates on the methodology and practical work related to the thesis. The primary source of information is numerous expert interviews ranging from service companies over drilling contractors up to specialized experts within the field of hammer drilling. It starts with introducing the relevant project, giving a detailed overview of project-related challenges and the well planning. Furthermore, the drilling method selection process, followed by the air hammer and rotary drilling setup, are thoroughly explained. Elaboration of operational parameters and minimum requirements for the air package and air hammer are detailed within the respective chapter. A list of most essential equipment, besides standard drilling equipment, for the provision of a functional air hammer system is given. In addition, lots identified to be necessary for a successful air hammer drilling operation are presented, and their respective scope of service is explained. Apart from this, the setup of the probabilistic time estimation (@Risk) comparing conventional technologies and the air hammer technology within the same lithology is discussed. Finally, the setup of a functional excel spreadsheet utilizes predefined project-specific input parameters to compare the technologies from an economic point of view and serves as a decision basis which technique to use is explained in detail. This excel spreadsheet will be used for the economic analysis, which compares estimated project cost using the conventional drilling approach vs. the air hammer drilling system (P10, P50, P70), based on offers from the industry. Additional information providing further in-depth knowledge related to topics covered was carefully selected and may be found within the appendix of this thesis.

Lastly, the results and discussion section provides an in-depth review of the conducted work and the obtained results, detailing the strengths and weaknesses of the selected methodology and the investigated technology. Recommendations for identified possible future work in the field of study may be found at the end of this thesis.

2 Fundamentals

The fundamentals section provides an overview of the wide variety of topics concerning drilling within the crystalline basement. A well-structured introduction into the different applicable rock destruction methods and drilling processes, including topics such as drill bits, rotary drilling within the crystalline basement, drilling fluid systems, and rotary percussive drilling, is given within this section. It starts with an introduction to hard rock drilling methods and will end with an introduction to down the hole button bits.

2.1 Introduction to Hard Rock Drilling Methods

This chapter gives an introduction into hard rock drilling fundamentals, starting with a characterization of various encountered rock types and an introduction to rock destruction mechanism. Furthermore, state of the art hard and abrasive rock drilling methods, including rotary and rotary percussive drilling amongst others, are discussed in detail.

2.1.1 Geological Settings

In order to reach a particular target, different types of rock must be drilled in geothermal and oil & gas drilling operations. Three basic types of rocks need to be distinguished. Sedimentary rocks play an important role in the oil & gas industry since major oil & gas fields are found in sedimentary basins. Other main groups are igneous rocks and metamorphic rocks. The term basement rock describes igneous and metamorphic rocks (crystalline rocks) usually found beneath layers of younger sedimentary rocks. (Campbell 2003)

2.1.1.1 Sedimentary Rocks

In contrast to igneous and metamorphic rocks, sedimentary rocks are formed at the earth’s surface under the influence of low temperatures and pressures. Sedimentary rocks are characterized by weathering and deposition through water, wind, or ice. The fundamental contrast in the origin of rocks leads to differences in chemical and physical characteristics of the three different rock types. The mineral and chemical composition, as well as the fossil content, distinguish sedimentary rocks from igneous and metamorphic rocks. Critical natural resources such as coal, salt, phosphorus, sulphur, iron, oil, and gas occur in sedimentary rocks. (Boggs 2010)

Sedimentary rocks can be classified into three main groups, siliciclastic sedimentary rocks, sedimentary carbonate rocks, and other chemical and biochemical sedimentary rocks. Siliciclastic sedimentary rocks include sandstones, conglomerates, mudstones, and shales. Limestones and dolomites are part of sedimentary carbonate rocks, while evaporites and cherts belong to other chemical and biochemical sedimentary rocks. (Boggs 2010)

Mechanical properties of rocks, such as the uniaxial compressive strength (UCS), hardness, and abrasion strength, indicate how hard it might be to drill a particular lithological sequence. Rocks with very high UCS and hardness values, as well as a high abrasion strength, require different drilling methods, like rocks with lower UCS and hardness values, as well as a low abrasion strength. Appendix A includes a summary of mechanical rock properties for selected types of rocks. Median values for the UCS of sandstones with various porosities lie between 50 and 100 MPa, while median values for the UCS of selected carbonate rocks lie between 40 and 120 MPa. The abrasion strength of selected sandstones lies between 9.9 and 56.4 $cm^3/50\ cm^2$. The abrasion strength of selected limestones and dolomites lies between 9.9 and 23.8 $cm^3/50\ cm^2$. A lower abrasion resistance value corresponds to a higher abrasiveness of the rock. (Siegesmund and Dürrast 2011)

2.1.1.2 Igneous Rocks

Since 90 to 95% of the upper 16 km of the earths solid crust consists of igneous or metamorphic rocks. (Prothero and Schwab 2004) These will be the encountered rock types when drilling within the crystalline basement.

Igneous or magmatic rocks form by cooling and solidification of once very hot magma (700 – 1,200°C) near the earth's surface. There are two distinct types of igneous rocks. Intrusive, or plutonic, rocks form where crystallization of magma happened below the surface, and extrusive, volcanic, rocks where cooling and subsequent crystallization occurred above the surface. Most famous plutonic igneous rocks are granitic rocks or granitoids. (Best 2006)

Appendix A includes a summary of mechanical rock properties for selected types of rocks. Median values for the UCS of plutonic rocks lie between 160 and 180 MPa. The abrasion strength of selected granites lies between 4.0 and 7.1 $cm^3/50\ cm^2$. (Siegesmund and Dürrast 2011)

2.1.1.3 Metamorphic Rocks

Sedimentary, igneous, or older metamorphic rocks that are subject to high temperatures (above 150 to 200°C) and pressures (above 1000 bar) are undergoing a process called metamorphism, causing a significant physical and or chemical change of the rock. The original rock is called protolith. One example of a metamorphic rock is gneiss. Gneiss can be found in various forms, such as para- and orthogneiss. The prefixes para- and ortho- are used to denote sedimentary and igneous protoliths. The orthogneiss, as mentioned above, is a metamorphosed granitic rock. (Best 2006) High-grade metamorphism of a sedimentary rock leads to paragneiss (metasediment). (Glass 2013)

Gneiss will be the predominant encountered rock type during drilling the geothermal well subject of this thesis, and therefore being of particular interest. Investigating the metamorphic fabric of gneiss, it turns out that foliation is very common for this type of metamorphic rock. Foliation is created by compositional layering or the orientation of mineral grains. If both kinds of foliation occur in the same rock, they are usually parallel (see Figure 1 for an illustration). (Best 2006)

Appendix A includes a summary of mechanical rock properties for selected types of rocks. Median values for the UCS of metamorphic rocks lie between 100 and 230 MPa, while the median value for the UCS of gneiss is obtained to be 175 MPa. The abrasion strength of gneiss lies between 9.3 and 11.4 $cm^3/50\ cm^2$. (Siegesmund and Dürrast 2011)

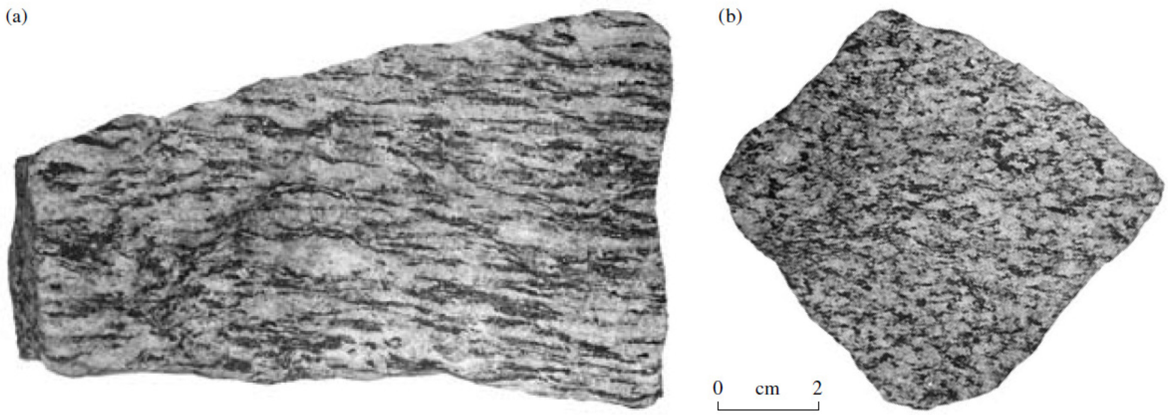

Figure 1: Parallel (a) and perpendicular (b) photos of lineated and weakly foliated gneiss[1]

2.1.2 Rock Destruction Mechanism

Three main approaches for rock drilling can be distinguished: mechanical loading (shear and impact forces), thermal (thermal spalling, melting and vaporization), and chemical techniques. (Maurer 1979) Investigations concerning a combination of the fundamental mechanism for hard rock drilling, are discussed in recent publications. A thermomechanical approach where thermal weakening of the rock happens before mechanical rock removal of the cutters is currently investigated. (Rossi et al. 2020)

2.1.2.1 Mechanical Rock Destruction

To drill a rock, forces causing stresses high enough to cause brittle failure or plastic yielding need to be applied. In rotary drilling, a mixture of crushing by using weight on bit (WOB) and shearing due to the rotational movement of the drill bit are the main rock destruction methods. Exceeding the yield stress of a rock leads, depending on the type of rock, to plastic deformation or brittle failure. While shear and tensional stresses cause failure of intergranular bonds, compressional stresses lead to crushing of grains and shear failure. The process of drilling imposes all three types of stresses (compression, tension, shearing) at different locations of the rock surrounding a drill bit. Generally the type and level of stresses imposed on a rock's surface is dependent on the type of drill bit, geometry of the borehole and the drilling mode (i.e., rotary drilling or percussion drilling) (Zacny and Bar-Cohen 2009)

Furthermore, penetration of rocks via water jets and particle streams is very effective and can be regarded as mechanical rock destruction. (Maurer 1979)

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[1] Best 2006. *Igneous and metamorphic petrology*, second. ed. Malden, Mass.: Blackwell.

2.1.2.2 Thermal Rock Destruction

Thermal spalling (400 – 600°C) and thermal melting and evaporation (1,100 – 2,200°C) are the two main thermal methods. (Zacny and Bar-Cohen 2009) The method of thermal spalling can be best described by the example of sandstone rocks within deserts. The difference in thermal expansion of the rock's constitutions, especially quartz, causes thermal-induced stresses within the rock. Cyclic loading, caused by heating during day and cooling during night, leads to micro-cracks and after enough time has passed, into breakage of the rock. This process is called onion weathering or exfoliation of the rock. The process is much faster if water is present in cracks within the rock. The effectiveness of thermal spalling in drilling depends on the rock composition (heterogeneity required) and the produced thermal gradients within the rock. (Zacny and Bar-Cohen 2009)

Melting and vaporization of rocks is another thermal rock destruction method. Literature shows that between 4,000 to 5,000 J/cm^3 are required to fuse most rocks, compared to 310 J/cm^3 for fusing ice. Very interestingly, it requires less energy to fuse through igneous rocks such as granite, than to fuse sedimentary rocks such as limestone and sandstone. This makes this method interesting for hard rock drilling. The heat required for the vaporization of a matter is much higher than the heat needed for melting the same matter. For example, more than four times more energy per gram of quartz is required for vaporization compared to melting. (Maurer 1979)

2.1.2.3 Chemical Rock Destruction

Widely used chemicals for rock destruction are fluorine or other halogens. (Maurer 1979) The method of chemically penetrating the surface of rocks can be highly effective but is not used in large scale commercial drilling operations. The violent chemical reaction required to penetrate rocks may cause fire and could be a potential threat to its users. (Zacny and Bar-Cohen 2009)

2.2 Rotary Drilling

The process of rotary drilling is based on three principles, rotation of the drill string, application of weight on bit (WOB), and circulation of a drilling fluid. For rotary drilling with drilling mud (water-based or oil-based), the hydraulic horsepower at the bit (HSI) plays an important role. Rotating of the bit under high weight causes, depending on bit type, slicing and crushing of the formation. The drilling fluid may be gaseous or fluidic and is required for adequate cutting transport to the surface, as well as cooling and lubricating the drill bit. The proper selection of bit type, drilling fluid, and operating parameter (WOB, RPM, pump rate), is a complex system depending on many parameters such as geological circumstances including, formation hardness and abrasiveness, pore and fracture pressures, formation temperature, directional drilling requirements and many more. Rotary drilling is the most used standard drilling method for oil and gas, as well as geothermal drilling projects. However, most effective for drilling within soft to medium strength sedimentary rocks, the rotary drilling process is as well applicable for drilling within hard and very hard crystalline basement formations. Proper selection of bit type, BHA configuration, operating parameter, drilling fluid, amongst others, is key to increase ROP and, therefore, the economic feasibility of rotary drilling within the crystalline basement.

2.2.1 Rotary Drill Bits

Four entirely different bit types are commercially available for rotary drilling applications (shown in Figure 2 to Figure 6).

Figure 2: Milled Tooth Bit[1]

Figure 3: Tungsten Carbide Insert Bit (TCI)[2]

Figure 4: Polycrystalline Diamond Compacts Bit (PDC)[3]

Figure 5: Natural/Impregnated Diamond Bit[4]

Figure 6: Hybrid Bit[5]

They are different in their design, primary rock destruction mechanism, and field of application. A variety of different bit designs is available from different manufacturers. Each type, with its unique characteristic, is intended to provide optimal performance in different kinds of

[1] 2020. *Milled (Steel) Tooth Bit, ECVV*, 28 April 2020, https://www.ecvv.com/product/4798367.html (accessed 28 April 2020).

[2] 2020. *TCI Tungsten Carbide Roller Cone Bit Hard Rock*, 28 April 2020, http://www.rock-drillingtools.com/sale-10759026-8-1-2-inch-iadc537-tci-roller-tricone-rock-drill-bits-tungsten-carbide-hard-rock.html (accessed 28 April 2020).

[3] 2020. *PDC Bit, SUSMAR*, 28 April 2020, https://www.susmar.fi/pdc/index.php/pdc-bits (accessed 28 April 2020).

[4] 2020. *Naturald Diamond Bit, DirectIndustry*, 28 April 2020, https://www.directindustry.com/prod/ge-compressors/product-115061-2074387.html (accessed 28 April 2020).

[5] Hsieh 2015. *Better and better, bit by bit*. *Drilling Contractor Magazine*, 9 July 2015, https://www.drillingcontractor.org/better-and-better-bit-by-bit-35780 (accessed 28 April 2020).

formations. Manufacturer consider many factors such as rock types to be drilled, expected rotary speed and WOB, hydraulics, dull conditions from abrasion and impact forces, hole depth and directional drilling requirements, drilling fluid characteristics, the operational mode of a drilling rig and many more. The main design points are the bit body, cone configurations, as well as cutter structures. (Lyons et al. 2016)

2.2.1.1 Roller Cone Bits

Roller cone bits are the most used bits within the drilling industry. Roller cone bits can be divided into two types, which are the milled tooth bit (soft to medium formations) and the insert bit (medium to very hard formations). The cutting action of roller cone bits comprises mainly of two mechanisms showed in Figure 9. The first mechanism is crushing of the formation due to applied WOB, which forces the inserts (or teeth) into the formation. The second mechanism is related to the fact that the axis of cone rotation is slightly angled to the axis of bit rotation, causing a skidding and gouging effect. (Lyons et al. 2016) Figure 7 shows the principal setup and main features of roller cone bits.

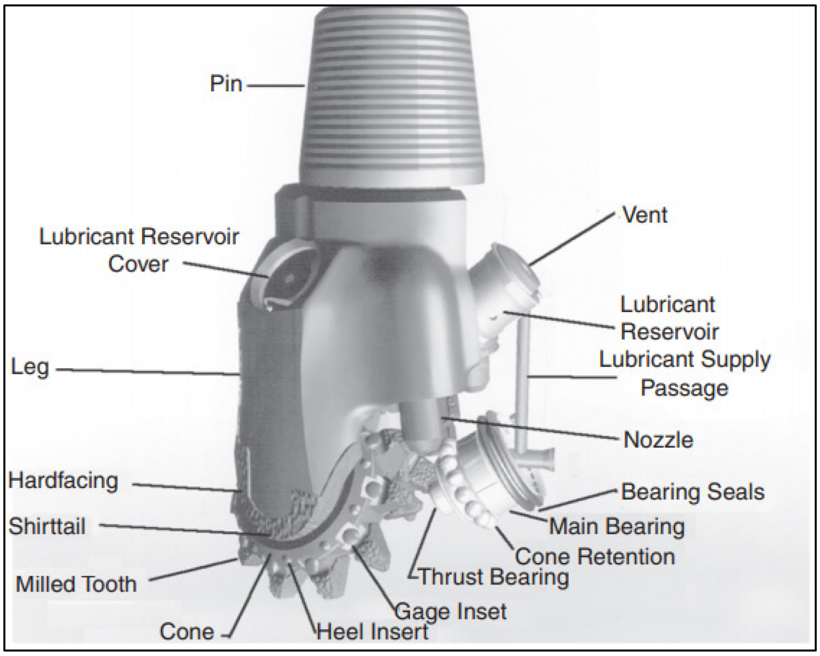

Figure 7: Main components of roller cone bits[1]

The design of a roller cone bit can be configured to make it most suitable for the application within very hard and abrasive crystalline basement rocks. Important design characteristics for hard rock roller cone bits are a large journal angle in combination with a small cone angle and small cone-diameter. Furthermore, small offsets (cone offset angle) are used in abrasive formations. Increased bearing size is used to withstand high WOB when drilling hard formations. The combination of above mentioned geometrical design points with short and

[1] Lyons et al. 2016. *Standard handbook of petroleum and natural gas engineering*, third edition. Waltham, MA: Gulf Professional Publishing.

rounded, heavy and closely spaced tungsten carbide inserts, provides the blueprint for a roller cone bit suited for hard and abrasive formations (see Figure 8). (Lyons et al. 2016)

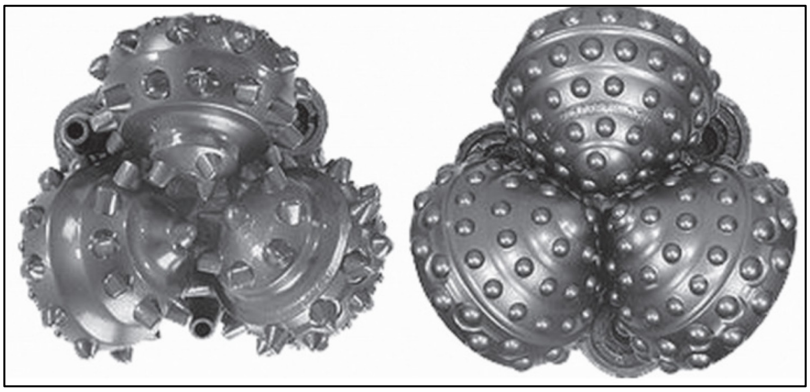

Figure 8: IADC 437X roller cone bit for softer formations (left) and IADC 837Y for harder formations (right)[1]

Table 1 gives a summarizing overview of the basic guidelines.

Table 1: Interrelationship between bit features, hydraulic requirements, and the formation[2]

Formation Characteristics	Insert/Tooth Spacing	Insert/Tooth Properties	Penetration and Cuttings Production	Cleaning/Hydraulic Flowrate Requirement
Soft	Wide	Long and sharp	High	High
Medium	Relatively wide	Shorter and stubbier	Relatively high	Relatively high
Hard	Close	Short and rounded	Relatively low	Relatively lower

Further features to increase the durability of roller cone bits within very hard and abrasive formations are: (Lyons et al. 2016)

- Shirttail hardfacing
- Heel row cutters
- Upper leg hardfacing
- Lug pads with carbide or diamond enhanced inserts
- Extended nozzles
- Flow tubes

[1] Lyons et al. 2016. *Standard handbook of petroleum and natural gas engineering*, third edition. Waltham, MA: Gulf Professional Publishing.

[2] Mitchell 2006. *Petroleum engineering handbook*. Richardson, Tex.: SPE.

- Center nozzles for bits > 16”

Journal bearings can typically sustain higher weights than roller bearings, while roller bearings can be run at higher speeds than journal bearings. (Mitchell 2006)

A detailed explanation for the IADC classification of roller cone bits can be found in Appendix B.

2.2.1.2 PDC Bits

Polycrystalline diamond compacts (PDC) bits nowadays outperform roller cone bits in soft and medium-hard formations in single run footage and single run penetration rate. (Lyons et al. 2016) The cutting action of PDC bits is mainly defined by shearing. A thrust plane for the cutter is defined by the vertical WOB and the horizontal rotational force. Cuttings are sheared off at an angle relative to the plane of thrust (see Figure 10). PDC bits require less WOB compared to roller cone bits. PDC bit bodies can either have a matrix structure or a steel structure. The matrix body is a heterogeneous material consisting of tungsten carbide grains metallurgically bonded with a soft and though metallic binder. Matrix body bits are durable in hard and erosive environments but have a low resistance to impact loading. Steel is relatively ductile and provides high resistance against impact loading. However, steel body bits would quickly fail in very hard and abrasive environments. Fortunately, steel body bits can be protected via hard facing features. PDC cutters consist of humanmade diamonds formed into shapes called diamond tables, which are the primary contact point of cutter and formation. These diamond tables have an essential feature, which distinguishes them from natural diamonds: They can be bond to tungsten carbide materials, which in turn, can be attached to the bit body. (Mitchell 2006)

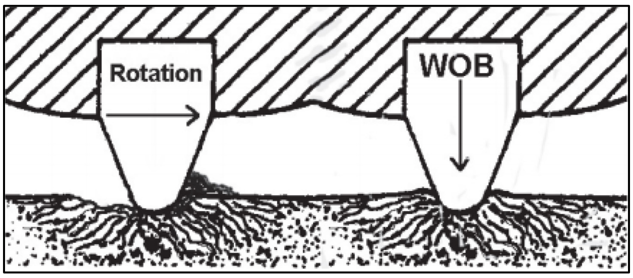

Figure 9: Cutting process typical for roller cone bits[1]

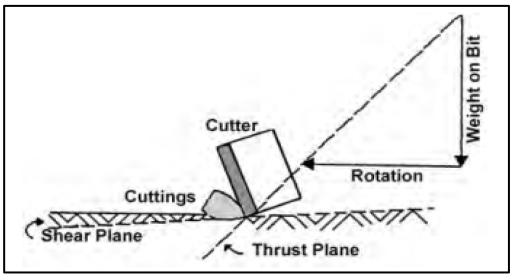

Figure 10: Cutting process typical for PDC bits[2]

Cutters should be orientated in a way that they are only loaded by compressional forces during operation. An increased cutter density yields into a reduction of cutting depth and, therefore, ROP, but bit life increases. A lower number of cutters results in an aggressive PDC bit behavior

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[1] Lyons et al. 2016. *Standard handbook of petroleum and natural gas engineering*, third edition. Waltham, MA: Gulf Professional Publishing.

[2] Mitchell 2006. *Petroleum engineering handbook*. Richardson, Tex.: SPE.

with increased ROP but decreased bit life. The back-rake angle (angle between the face of a cutter and a line perpendicular to the formation being drilled) defines the aggressiveness of the bit. An increased back-rake angle should be used for hard formations since it increases cutter and therefore bit life. PDC bit profiles exist from flat to long parabolic profiles. Flat profiles, in combination with a high cutter density, is recommended for hard formations. (Mitchell 2006)

Bit manufacturers continuously try to improve the PDC bit performance by increasing both ROP and durability within very hard and abrasive rocks. A new approach to enhance the PDC performance was attempted by the design of a new cutter element, which allowed to design a bit exhibiting shearing and crushing forces onto the formation. The focus lies on a conical shaped polycrystalline diamond element (CDE) with a thick synthetic diamond layer. (Azar et al. 2013)

Impact tests conducted on stinger cutter elements and conventional PDC cutter elements showed a higher impact resistance of the stinger elements. A further laboratory test with a rotating test bed of granite (207 MPa UCS) was conducted to measure wear resistance of the stinger element. The outcome was that the CDE cutter element showed greater cutting efficiency and wear resistance compared to a standard PDC cutter. Simulations (see Figure 11) showed that, by creating high stress concentrations at the contact point, CDE cutter elements increase rock fracture generation while requiring less applied force. (Azar et al. 2015)

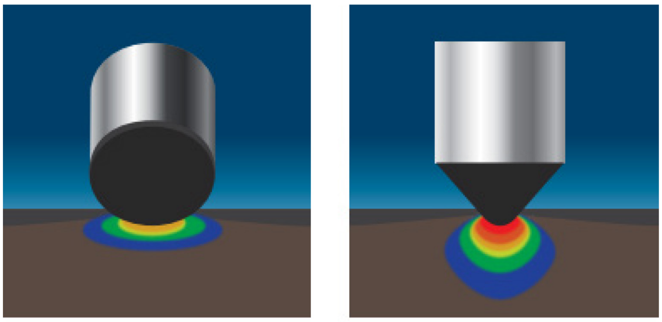

Figure 11: Finite Element (FE) modeling shows the concentrated stress a 3D conical stinger element enacts on the formation (right) in contrast to a standard PDC cutter (left)[1]

Different variations of PDC bits related to their cutter arrangement are commercially available on the market. Every bit is specially designed for a particular environment. Figure 12 shows two variations. On the right-hand side, a cutter arrangement intended for drilling hard carbonates with high concentrations of chert is shown, while the bit on the left-hand side is designed for drilling extremely hard and abrasive igneous rocks such as granite. (Azar et al. 2015)

[1] Smith Bits - A Schlumberger Company 2014. *StingBlade: Conical diamond element bit*, https://www.slb.com/-/media/files/smith/brochures/stingblade-br.ashx (accessed 3 May 2020).

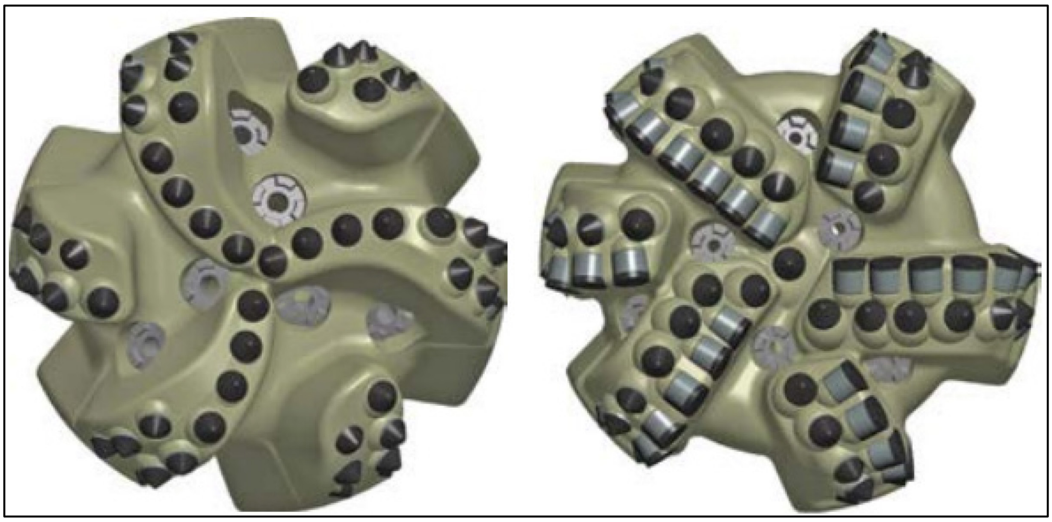

Figure 12: Full stinger (left) and sting blade (right) PDC bits[1]

2.2.1.3 Hybrid Bits

Hybrid bits try to combine the best of two worlds (roller cone and PDC bits). The combination of the roller cone crushing action with the PDC shearing action (see Figure 13) results in higher ROP compared to TCI bits while still maintaining good steerability. The Kymera™ hybrid bit showed excellent performance when run in basalt within the Theistareykir geothermal field in 2011. A 17.1/2" Kymera™ bit drilled 173 m at an average ROP three times faster than conventional roller cone bits run in offset wells. Directional requirements, at an average ROP of approximately 5 m/h faster than the best TCI in the field, were met with a 12.1/4" Kymera™ bit. (Rickard et al. 2014)

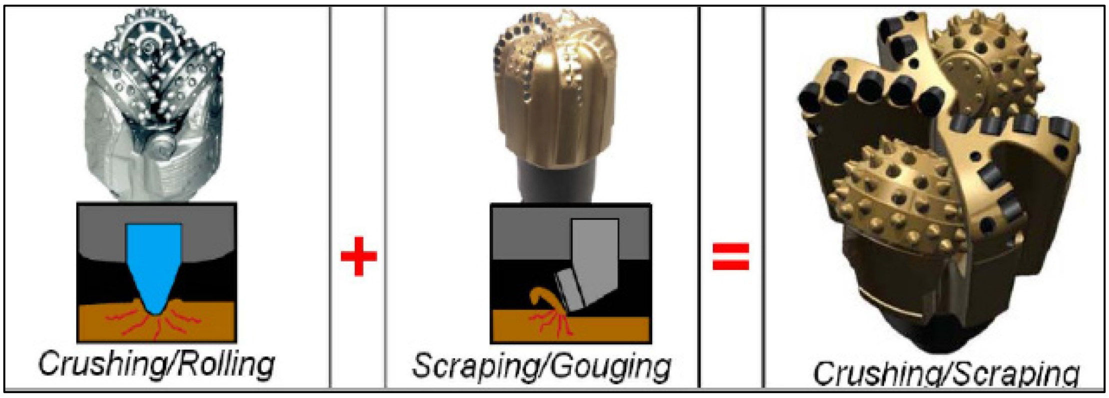

Figure 13: Cutting action of a hybrid bit[2]

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[1] Azar et al. 2015. *A New Approach to Fixed Cutter Bits*. Houston, Texas, https://www.slb.com/-/media/files/oilfield-review/03-cutterbit.ashx?la=en&hash=30D491A0FF5F821C0489BDE0C95121C3 (accessed 3 May 2020).

[2] Blakney et al. 2019. *Combining State-of-the-Art Hybrid Bit and Positive Displacement Motors Saves 863,670 CAD Over 20 Wells in Northern Alberta, Canada*. https://doi.org/10.2118/195237-MS.

2.2.1.4 Impregnated Bits

Impregnated Bits are a type of PDC bit in which diamond cutting elements are fully embedded in the bit body matrix. The bit body material of impregnated bits is comparable to matrix material used in PDC cutters. Natural diamonds, synthetic diamonds, PDC, and thermally stable PDC (TSP) are used in combination with impregnated bits. By being embedded in the bit body, natural as well as synthetic diamonds are less susceptible to breakage. Enforced by a relatively small cut depth, ROP must be achieved by high rotational speeds (500 to 1,500 RPM), which can be achieved by use of high-speed positive displacement motors (PDM) and turbodrills. (Mitchell 2006)

Drill bits form a vital component of the BHA and should be carefully selected to get the best performance possible. BHA selection in general is an important task which should be undertaken considering all relevant boundary conditions upfront the start of the basement drilling project. This thesis summarizes most important BHA components with respective features making them suitable for hard rock drilling application. The summary may be found in Appendix C.

2.3 Drilling Fluid Systems for Drilling within the Crystalline Basement

Drilling fluid systems play an essential role in drilling a well safely and economically. A drilling fluid cleans, lubricates, and cools the drill bit, carries away cuttings, and therefore cleans the borehole. Furthermore, balancing of formation fluids and stabilizing the borehole are amongst other tasks performed by drilling fluids. Hydraulic fluid-rock interaction (e.g., hydraulic horsepower per square inch (HSI), Bit jet velocity) allows improving drilling performance within hard rocks. This chapter will give an introducing overview of different fluid systems with a special focus on underbalanced drilling.

Drilling fluids can be classified by their basic composition into the groups shown in Figure 14. Water-based mud systems (WBM) like water bentonite, potassium carbonate, or water polymer mud systems are frequently used in geothermal deep drilling operations. Oil-based mud systems (OBM) and synthetic-based mud systems (SBM) are less commonly used in geothermal drilling operations due to strict environmental regulations. Gas-liquid systems (aerated liquid) and all gas systems are frequently used for underbalanced drilling.

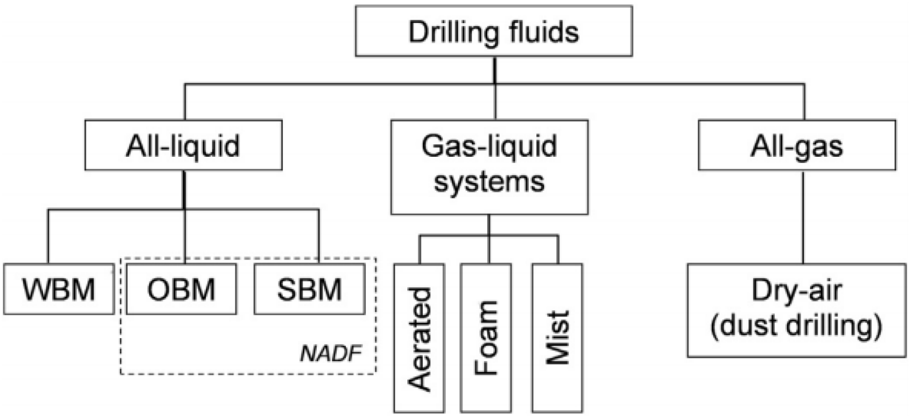

Figure 14: Drilling fluid classification (NADF are non-aqueous drilling fluids)[1]

2.3.1 Underbalanced Drilling

Drilling operations where a drilling fluid, providing a bottom hole pressure lower than the formation pressure, is used, are known as underbalanced drilling (UBD). Underbalanced drilling is usually performed by utilizing light drilling fluids such as air, gas, foam, and aerated mud. However, if the formation pressure is high underbalanced drilling can be performed with water and oil-based mud systems. (Guo and Ghalambor 2005) Out of interest for this thesis, air and foam drilling systems will be discussed in detail.

Underbalanced drilling is becoming increasingly popular for drilling within hard and abrasive formations. This is linked to various advantages found with underbalanced drilling (Guo and Ghalambor 2005; Rehm 2012):

- Increase in ROP
- Limiting reservoir damage
- Avoiding lost circulation issues
- Minimized differential sticking
- Prolonged bit life
- Improved formation evaluation

Disadvantages are limitations to wellbore stability and an uncontrolled influx of formation fluids. (Rehm 2012)

Increase of ROP, prolonged bit life, and avoidance of lost circulation issues are of particular interest when drilling within fractured crystalline basement. The drilling rate of bits (especially insert bits) is highly responsive to the differential pressure between the wellbore and the formation. A lower wellbore pressure reduces the “chip hold down” effect and causes the rock to behave more brittle under the bit cutter. (Guo and Ghalambor 2005)

[1] Lavrov 2016. *Lost circulation: Mechanisms and solutions*. Amsterdam: Gulf Professional Publishing is an imprint of Elsevier, http://www.sciencedirect.com/science/book/9780128039168.

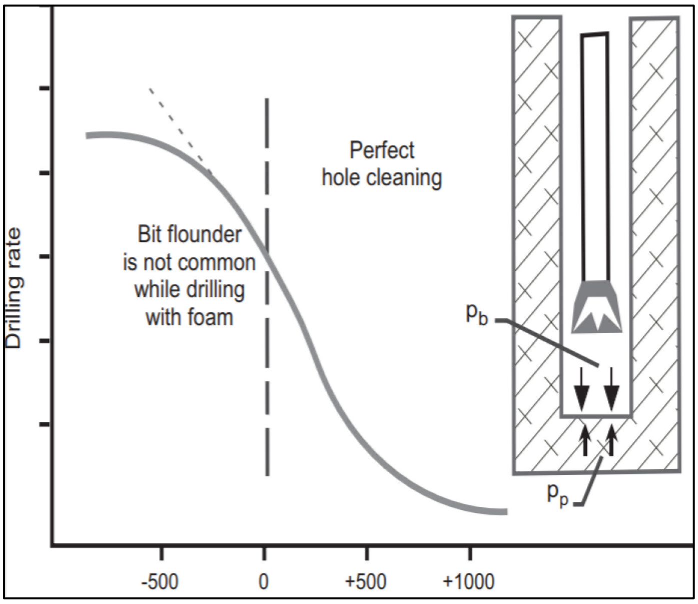

Figure 15: Schematic illustration coupling differential pressure (dimensionless) and drilling rate (dimensionless)[1]

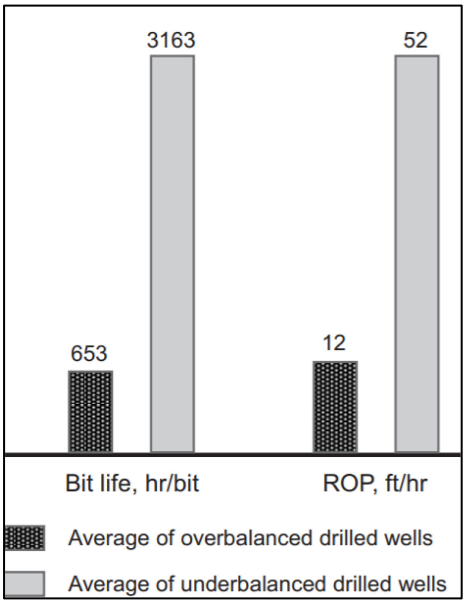

Figure 16: Data from Saudi Aramco´s UBD campaign[2]

Main operational systems used for underbalanced drilling are aerated mud drilling, foam drilling, and air or gas drilling. The following Figure 17 to Figure 20 provide a guideline for the selection of a proper underbalanced fluid system depending on type of formation and expected drilling challenges. In general, the statement, the lighter the drilling fluid, the higher the potential to drill hard rocks, can be confirmed. (Guo and Ghalambor 2005)

Table 2 provides an overview of specific gravities of selected drilling fluid systems.

Table 2: Specific gravities of various drilling fluid systems[2]

Drilling Fluid	Specific Gravity
Water-based bentonite mud	1.1
Water	1.0
Oil-based muds	0.82
Aerated bentonite mud	0.4 - 1.1
Aerated water	0.3 - 1.0
Mist	0.05 – 0.4
Foam	0.05 – 0.25
Air	0.03 – 0.05

[1,2] Guo and Ghalambor 2005. *Gas volume requirements for underbalanced drilling: Deviated holes*. Norwood Mass.

[2] Hagen 2006. *AERATED FLUIDS FOR DRILLING OF GEOTHERMAL WELLS*, 2006.

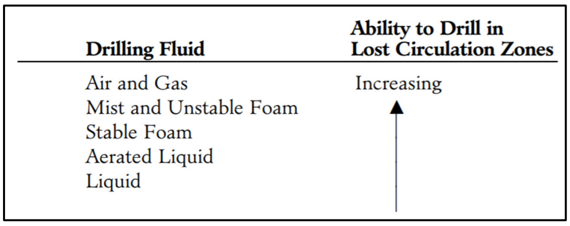

Figure 17: Fluid systems and lost circulation[1]

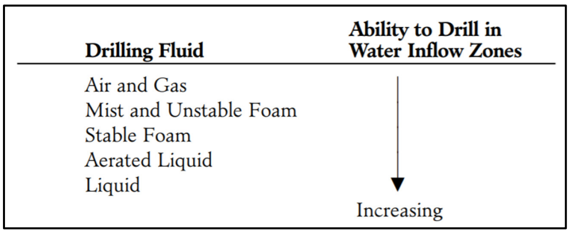

Figure 18: Fluid systems and water inflow[2]

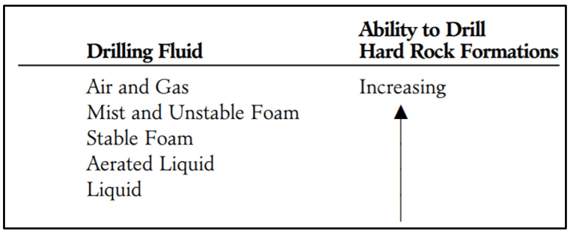

Figure 19: Fluid systems and hard rock drilling[3]

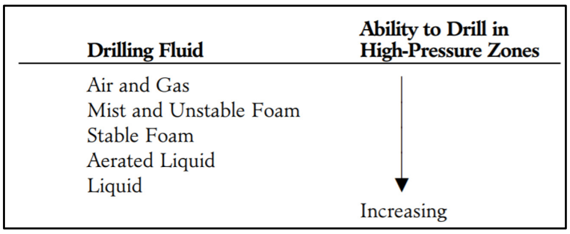

Figure 20: Fluid systems and high-pressure zones[4]

2.3.1.1 Aerated Drilling

Aerated drilling is achieved by the addition of compressed air or other gases to the drilling fluid circulating system. This reduces the hydrostatic weight of the fluid column within the well and allows to utilize the advantages outlined in section 2.3.1. (Hagen 2006) Most used gas injection methods are drill string injection, parasite string injection, parasite casing injection, and through completion injection. All, except for the drill string injection, are annulus injection methods. The drill string injection method (gas and liquid are injected to the standpipe) is very common due to its simplicity and low cost. Borehole washouts may occur within the open hole section due to high velocities of the aerated drilling fluid around drill collars. Side-jet subs can be used to divert some of the airflow towards the annulus within the cased hole section. Figure 21 shows the basic principle of parasite string injection. (Guo and Liu 2011)

[1,2,3,4] Guo and Ghalambor 2005. *Gas volume requirements for underbalanced drilling: Deviated holes*. Norwood Mass.

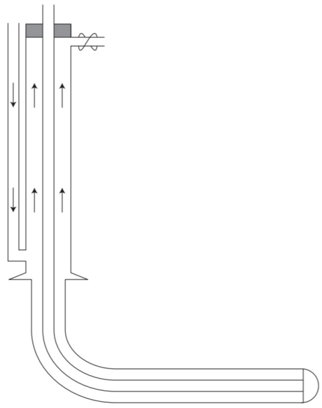

Figure 21: Schematic representation of parasite string injection[1]

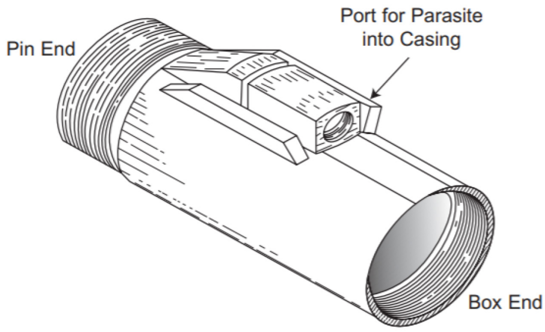

Figure 22: Gas injection sub[2]

Figure 23 shows the schematic for an aerated drilling setup, detailing necessary equipment and connections. The configuration was used for drilling a geothermal well with a Drillmec HH-300 drilling rig in the Hellisheidi geothermal field in Iceland. The difference in required surface equipment for air or mist drilling and aerated fluid drilling is found when comparing Figure 24 to Figure 23. The shown equipment will be explained in detail within section 2.3.1.2.

[1,2] Guo and Liu 2011. *Applied drilling circulation systems: Hydraulics, calculations, and models*. Amsterdam, Boston, Burlington, Mass.: Elsevier; Gulf Professional Pub.

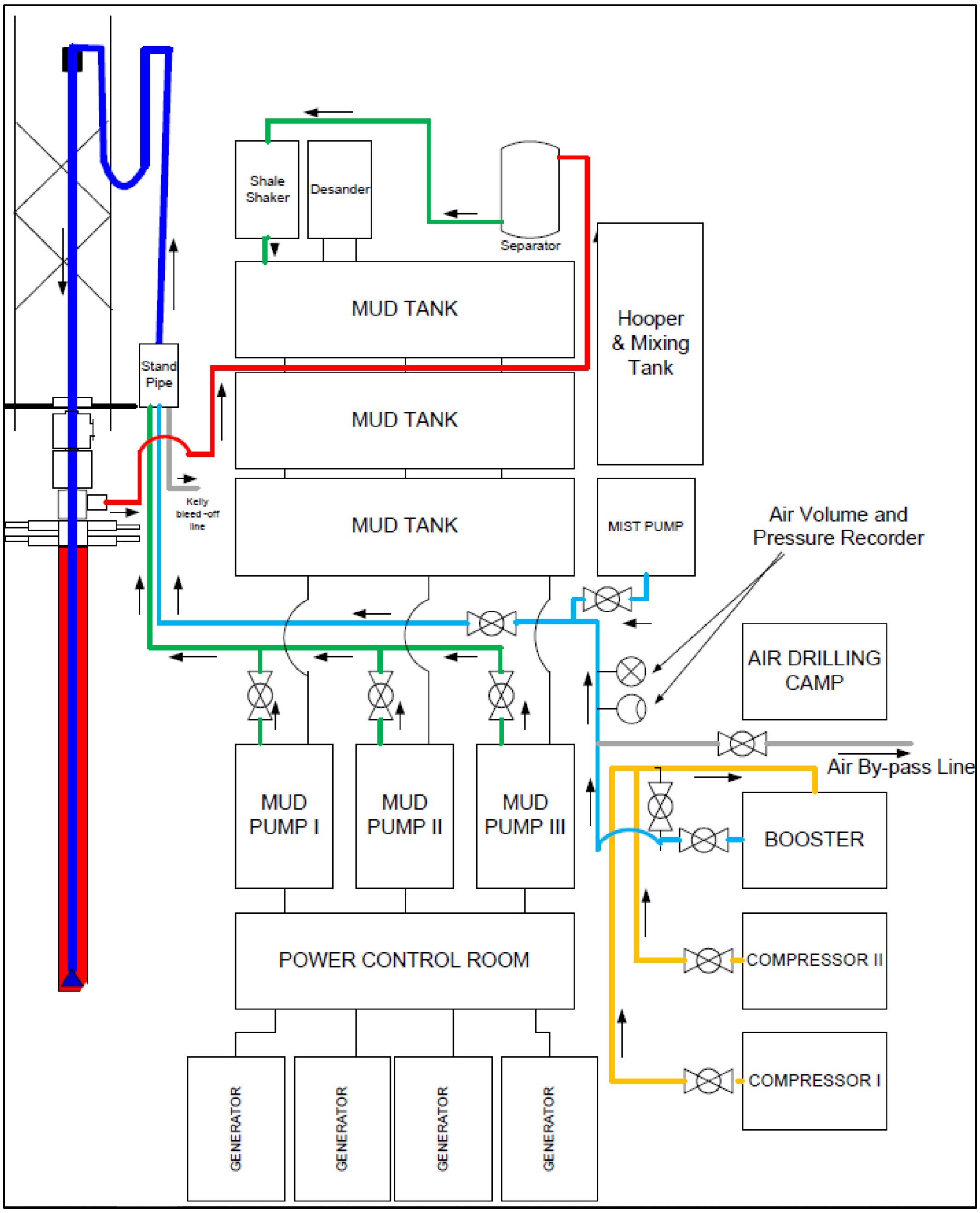

Figure 23: Schematic setup for an aerated drilling operation[1]

2.3.1.2 Air or Gas Drilling

Air or gas (natural gas, nitrogen) drilling operations are the ultimate underbalanced drilling operation. Still, they do not belong to managed pressure drilling (MPD) since the wellbore pressure management is not a practical part of air drilling. The main goal is to achieve minimum bottom hole pressure, and therefore maximum drilling rate. (Rehm 2012) Air drilling is utilized when working with down the hole pneumatic hammer systems. Thus, the operational setup

[1] Kesuma and Putra 2008. *DRILLING PRACTICE WITH AERATED DRILLING FLUID: INDONESIAN AND ICELANDIC GEOTHERMAL FIELDS*. Orkustofnun, Reykjavik, 2008.

(equipment, operational parameter, operating procedures) of air drilling is of special focus for this thesis.

Figure 24 shows the schematic setup for an air drilling operation. Most important surface equipment components are the air package (compressor and booster), air volume and pressure recorder, air manifold, rotating head (RCD), blooie line and the piping system connecting all relevant parts (pressure lines, valves, gauges, connections, etc.)

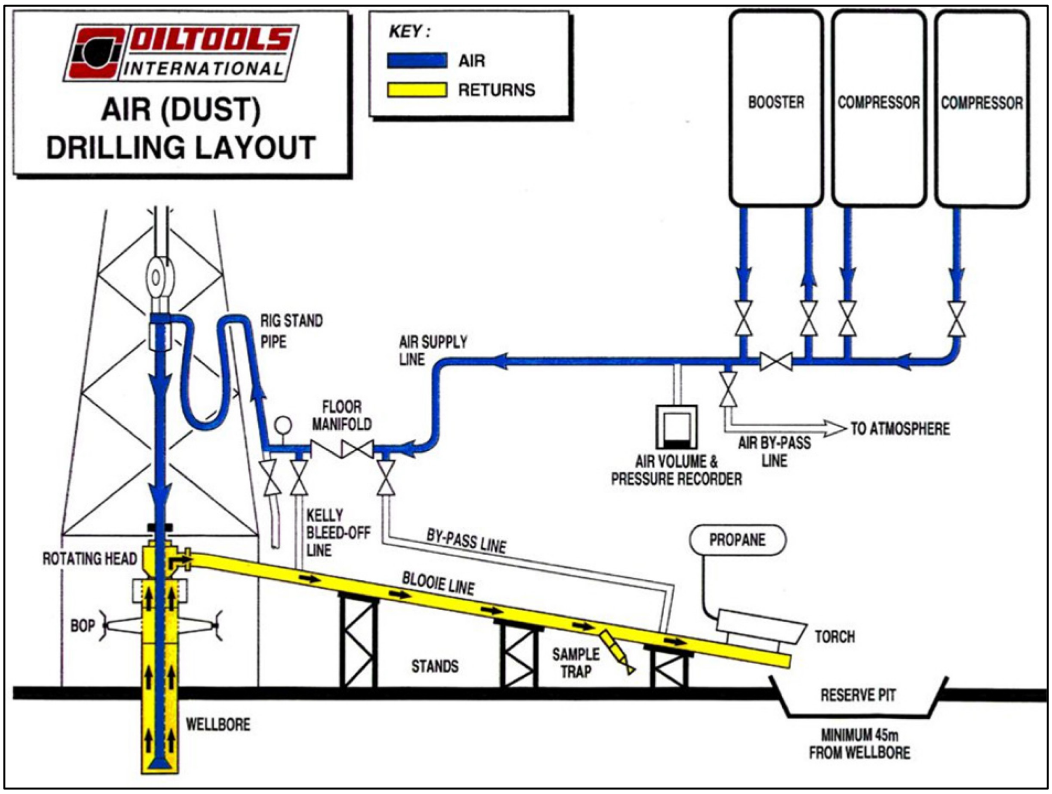

Figure 24: Schematic setup for an air drilling operation[1]

Direct and Reverse Circulation Systems

Two basic circulating systems need to be distinguished. The more common direct circulation where the drilling fluid travels from the pumps to the inside of the drill string and through the bit to the annulus of the well and further via the annulus to the solid control system on the surface. The reverse circulation system can be useful for drilling large diameter shallow holes. The drilling fluid travels from the pumps to the annulus between the borehole wall and drill pipe and onwards to the bottom of the hole were cuttings are carried away through a large opening within the drill bit through the inside of the drill string to the surface. Closed reverse circulation systems can be achieved by utilizing dual wall drill pipes and special drill bits. (LYONS 2009)

[1] Oiltools International. *Air (Dust) Drilling Layout*, https://slideplayer.com/slide/5747410/19/images/39/Air%2FDust+Drilling+Layout.jpg (accessed 23 May 2020).

Surface and Downhole Equipment

The following pages deal with surface equipment necessary to establish a functional air drilling system. The equipment is listed and explained following the path of air along with a typical air drilling setup.

Air Package

The air package consists of one or more compressors and one or more booster. A primary compressor intakes air from the atmosphere and mechanically compresses the air in several stages (e.g., Atlas Copco Drill air Y35 Stage IV diesel driven compressor which can deliver 39.8 m^3/min at 25 bar or 35.4 m^3/min at 35 bar (Atlas Copco 2020b)). Boosters are used to increase further the pressure of air expelled from the primary compressor (e.g., Atlas Copco Containerized Air Booster B18TT-62-3000 diesel-driven, which can handle 127 m^3/min at 34 bar of intake air and elevate the pressure to 100 bar when operated as single stage (Atlas Copco 2020a)). This is especially needed when operating special downhole equipment such as down the hole hammer, or for very deep wells, or wells with significant water inflow. It is crucial to derate the performance of compressors and boosters if they are operated above sea level elevation. The fuel consumption of compressors and booster needs to be closely monitored since it contributes heavily to the per meter drilling cost. (Lyons et al. 2009)

Valves, Gauges, and Air Volume and Pressure Recorder

Further down the flowline from the air package to the rig standpipe, an assembly of ball or gate valves (manually and remotely operated), check valves, pressure, and temperature gauges, and an air volume (orifice plate or turbine flowmeter) and pressure recorder is installed. This equipment is an integral part of an air drilling surface setup and allows to control the air drilling operations. Safety valves with bypass lines allow to either vent air to the atmosphere or into the blooie line for the event operating pressure limits are exceeded. The flow lines are very often API 2.7/8" or 3" high-pressure steel lines (Chiksan lines). Mud pressure gauges at the rig floor must be changed to gas gauges having the appropriate pressure rating. (Lyons et al. 2009)

Scrubber

A scrubbing unit removes excess water from the airflow right after the compressor and can be used in case only dry air is required. (Lyons et al. 2009)

Air Manifold

The air manifold directs the pressurized air within the flowline coming from the air package towards the rig standpipe, or away to the blooie line. Usually, the air manifold is located on the drill floor to allow the rig personnel to divert the airflow and blowdown pressure to enable connections to be made during the drilling operation. (Lyons et al. 2009)

Float Valves

Float valves (dart type or flapper type) are installed within the drill string to prevent backflow of formation fluids or pressurized air through the drill string to the surface. Float valves may be inserted to the drill string every 300 m to decrease pressure fluctuations during connections and maintain a lower bottom hole pressure. (Kesuma and Putra 2008)

When used within very hard formations, the air may pass on its way through the drill string to the bottom of the well, a down the hole hammer with a button bit or a TCI bit. The former and the latter are discussed in separate chapters.

BOP Equipment and Rotating Head

Figure 25 shows a possible BOP assembly for air drilling. However, more recent BOP configurations are of ram, spool, double ram, annular preventer (RSR_DA) type. An essential tool is a rotating head or a comparable flow diverter (see Figure 26) at the top of the annular preventer. The rotating head consists of a packing element that rotates with the drill string and provides a pressure-tight seal across the annulus. The returning fluid (air, liquid, cuttings) from the well is diverted by the seal to the blooie line. Depending on the design of the rotating head, it may be possible to inject cooling water to prolong the life of the packing element and the bearings.

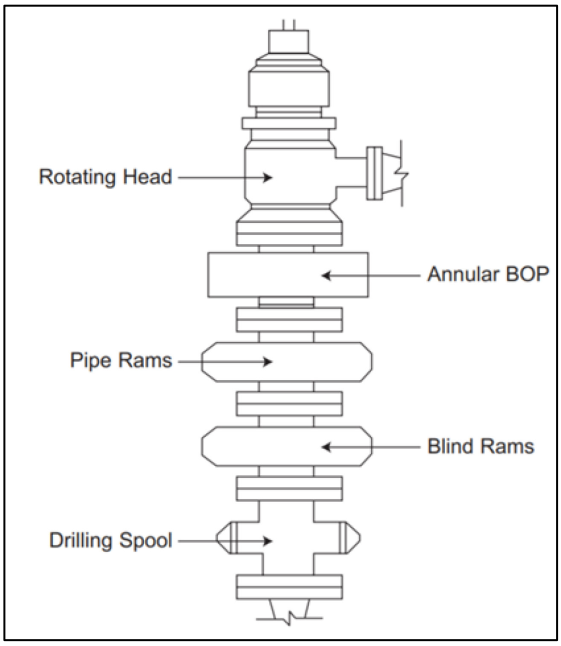

Figure 25: Typical air drilling BOP stack with a rotating head[1]

[1] Guo and Liu 2011. *Applied drilling circulation systems: Hydraulics, calculations, and models*. Amsterdam, Boston, Burlington, Mass.: Elsevier; Gulf Professional Pub.

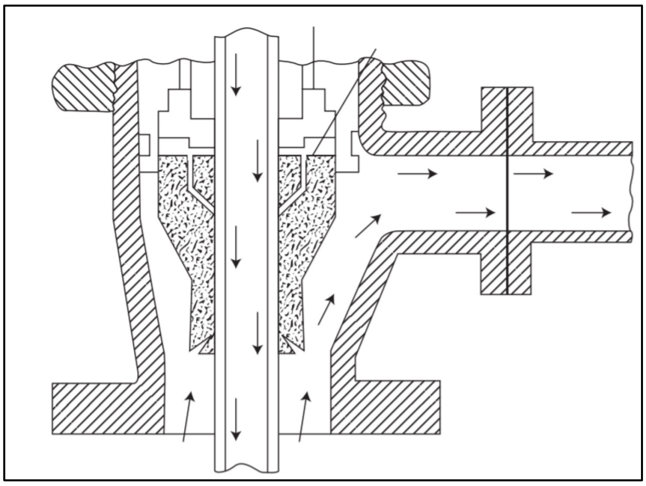

Figure 27: Cross-sectional view of an RCD[2]

Figure 26: Rotating control device (RCD)[1]

Blooie Line

The flowline which diverts the fluid from the rotating head towards the separator, solid control equipment, or directly towards a blow pit, is called blooie line. The blooie line should have a diameter large enough (approx. 1.1 times the cross-sectional area of the annulus of the top-hole section) to allow unrestricted flow of drilling fluid and cuttings away from the rotating head. The typical blooie line length is anything between 30 to 90 m, depending on the available space at the rig site. Every blooie line is equipped with two high-pressure gate valves located directly at the beginning of the line just after the rotating head. Furthermore, the blooie line is equipped with a sample catcher setup for mudlogging purposes (see Figure 29). (Lyons et al. 2009) Figure 28 shows the blow pit with a constructed berm to catch the high-velocity mixture of air, liquid, and solid particles exiting the blooie line. The blow pit is sloping slowly but steadily towards a reserve pit. The blow and reserve bit should be designed and constructed large enough to catch and collect the fluid at the surface. (Lyons et al. 2016)

[1] Weatherford 2020. *Rotating Control Devices: Creating a pressure-tight barrier against drilling hazards*, 2020, https://www.weatherford.com/en/products-and-services/drilling/managed-pressure-drilling/rotating-control-devices/ (accessed 23 May 2020).

[2] Guo and Liu 2011. *Applied drilling circulation systems: Hydraulics, calculations, and models*. Amsterdam, Boston, Burlington, Mass.: Elsevier; Gulf Professional Pub.

Air Drilling Separator (Cyclone)

The air drilling separator which is used to separate air, water and cuttings follows the basic operating principle of a hydrocyclone. (2000) The separator is an integral part of the solid control system in air drilling operations, especially at small drilling sites where the use of blow pits is not possible, and mounted into the system following the blooie line (see Figure 23). The tangential entry cyclone is preferably mounted on an elevated framework to provide the possibility for cutting tanks to be placed underneath to allow collecting cuttings and water within the underflow, or an follow up cutting treatment with the rigs conventional solid control system (e.g. shaker, desander, desilter, flocculation unit, centrifuge). (Hagen 2006)

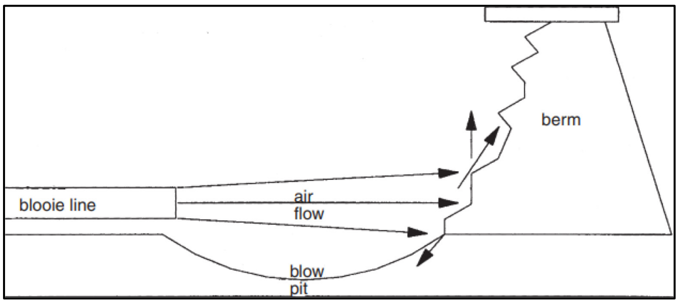

Figure 28: Blooie line exiting into a blow pit[1]

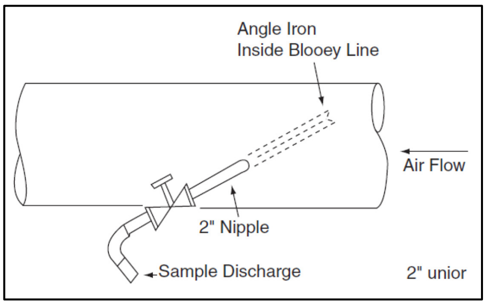

Figure 29: Sample catcher design[2]

2.3.1.3 Unstable Foam or Mist Drilling

If air as drilling fluid is not able to provide sufficient hole cleaning, which may be the case in large diameter surface sections, or wells with high water influx (liquid loading), drilling foam is used in order to guarantee sufficient cutting transport and unloading of the well.

Mist or unstable foam drilling is used to increase the ability to lift formation water out of the hole. In case only dry air is used, part of the formation water would be absorbed as water vapor by the hot air when leaving the bit nozzles. However, this saturation process would lead to a decrease in internal energy and, therefore, a dramatic reduction of kinetic energy (reduction in velocity), leading to reduced borehole cleaning abilities. By injecting water (mist pump), a saturated gas with excellent cutting carrying ability is created. Unstable foam drilling is used in case misted air does not provide the required cutting carrying abilities anymore. Foaming agents are added to the fluid injected with the mist pump to obtain drilling foam. Table 4 shows a typical formulation for unstable foam drilling (actual product volumes may vary). (Lyons et al. 2009)

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[1] Lyons et al. 2016. *Standard handbook of petroleum and natural gas engineering*, third edition. Waltham, MA: Gulf Professional Publishing.

[2] Lyons et al. 2009. *Air and Gas Drilling Field Guide: Applications for Oil and Gas Application for Oil and Gas Recovery Wells and Geothermal Fluids Recovery Wells*, Third Edition. Elsevier.

Water injection rates depend on air pressure and application boundary conditions. Table 3 gives an overview of recommended injection rates depending on air hammer size. (Halco Rock Tools Limited)

Table 3: Recommended water injection rate for mist/foam drilling (modified after (Halco Rock Tools Limited))

Nominal Hammer Size [in]	Recommended Injection Rate [l/min]
5	5 - 8
6	7 - 10
8	8 - 15
12	12 - 24

Polymers like PAC L, PAC R, or Xanthan are used as foam extender or stiffener. (Litke 2019) Foam is relatively temperature-sensitive and starts to degrade with bottom hole temperatures above 100°. (Rehm 2012) However, biodegradable foaming agents rated for bottom hole temperatures up to 200°C are available. (Todd 2019)

Table 4: Approximate quantity of additives for unstable foam drilling (modified after (Lyons et al. 2009))

Additives	Volume per m^3 of freshwater
Foaming agent	5 to 10 l
Polymer	0.3 to 0.6 l
Corrosion inhibitor	0.6 l

Another source states an recommended polymer (Xanthan) dosage of 1.4 kg per m^3 of freshwater. (Air Drilling Associates Pte Ltd. 2020)

It is important to not mistake unstable foam drilling with stable foam drilling (creation of a stiff and continuous foam phase), which is not within the scope of this thesis.

Figure 30 shows the schematic layout for a mist or foam drilling operation.

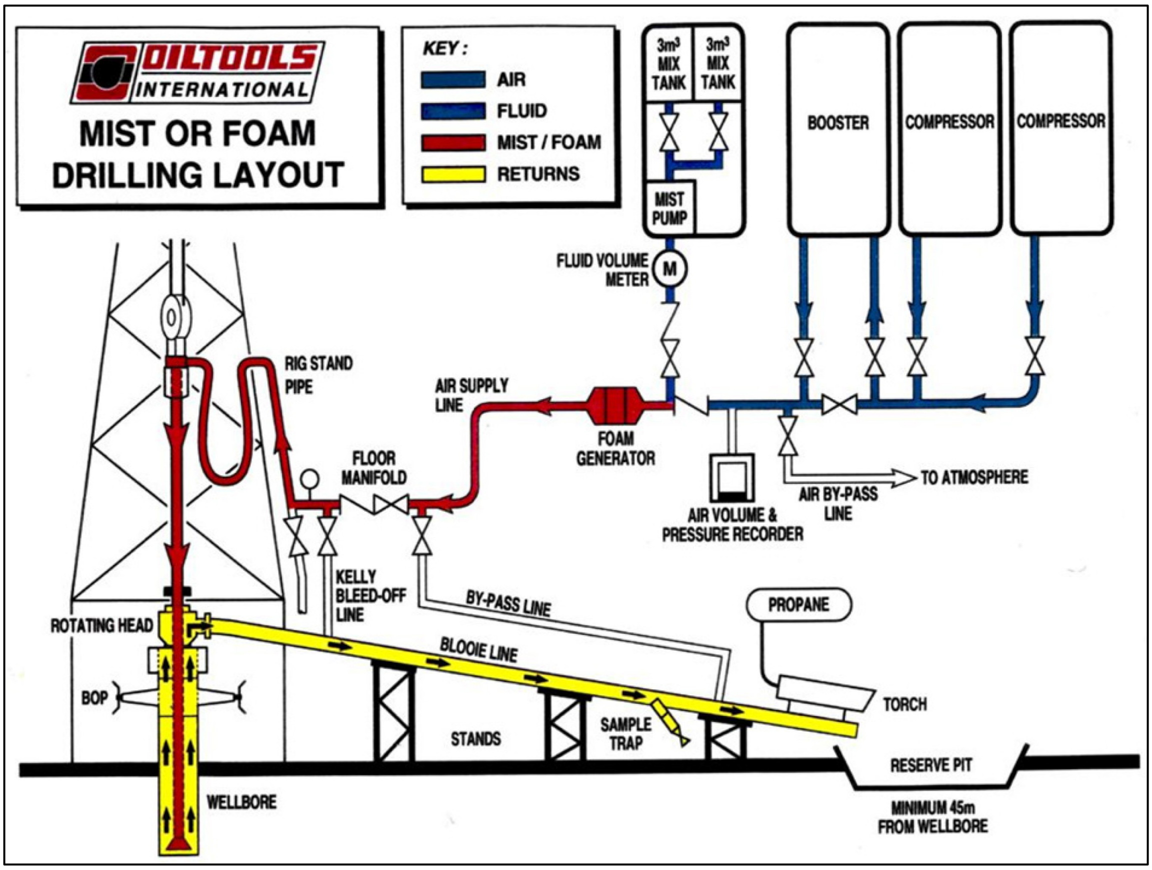

Figure 30: Schematic setup for a mist or foam drilling operation[1]

Mist Pump and Foam Generator

To inject water enriched with foaming agents into the air stream coming from the air package, a small triplex pump with coupled metering pumps for injecting foaming agents, is used. These pumps have capacities of pumping up to 300 l/min. (Hagen 2006) The pump needs to have a high-pressure rating since the water and foam additives will be injected directly into the airflow at potentially boosted pressures. (Beare 2019) In the case of unstable foam drilling part of the foaming happens prior reaching the drill bit, while bulk of the foaming happens through shearing the misted air mixture enriched with foaming additives through the nozzles at the drill bit. (Lyons et al. 2009)

The foam generator can be considered as optional equipment since it is required for conducting stable foam drilling, which is not within the scope of this thesis. (Guo and Ghalambor 2005)

[1] Oiltools International. *Mist of Foam Drilling Layout*, https://slideplayer.com/slide/5747410/19/images/47/Mist+or+Foam+Drilling+Layout.jpg (accessed 23 May 2020).

Returned Foam Handling

Proper handling of returned foam is an essential topic in terms of surface storage area and therefore cost. Most systems are one-pass systems meaning that the foam will be utilized once and then discarded to blow or storage pits via the blooie line. It is intended to give the foam time for degradation and recycle or clean and dispose of the remaining water, chemicals, and cuttings. Most foaming agents and additives are biodegradable and only present in small quantities. However, depending on the stiffness of the foam, it may take up to a few days for the foam to decompose naturally. Therefore, the returned foam is broken down using defoamer (acids, alcohols) or separators (cyclone). The use of defoamer results in a volume reduction of up to 95% within seconds (half-life from six minutes to less than 15 seconds). Depending on the intended disposal and solid control actions, the defoamed fluid can go to the shale shakers and further on through the solid control system or may be disposed in open surface pits where the cuttings are allowed to settle. (Guo and Liu 2011, 2011)

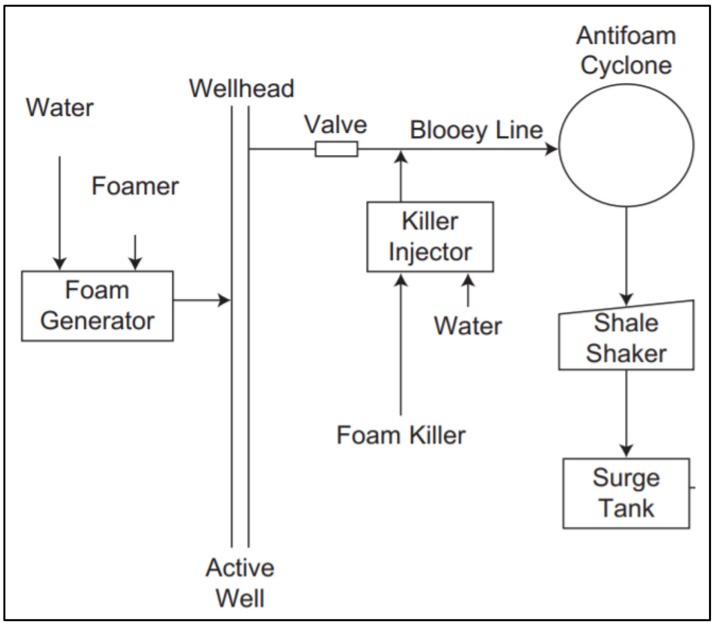

Figure 31: Schematic for a returned foam treatment setup[1]

Experiments conducted with a silicone and mineral oil free defoamer based on rape seed oil showed promising results when used at a concentration of 2% (2 liter of defoamer on 1 m³ of foamed water). (Air Drilling Associates Pte Ltd. 2020)

[1] Guo and Liu 2011. *Applied drilling circulation systems: Hydraulics, calculations, and models*. Amsterdam, Boston, Burlington, Mass.: Elsevier; Gulf Professional Pub.

2.3.1.4 Operational Procedures and Operating Parameter

This chapter will introduce operational parameters (volume, pressure) of the air package, and operational procedures (making connections, trips, unloading a hole full of water, etc.) when conducting air or unstable foam drilling.

Air Injection Rate and Pressure

The air injection rate and pressure requirements should be carefully calculated to select an adequate air package fulfilling the requirements.

Different models and approaches for a detailed calculation of the required air injection rate and pressure exist within the literature. However, the exact implementation of the models and equations into a numerical solver or spreadsheet lies not within the scope of this thesis and could be part of future work. For the time being, it is convenient to use correlations and provided engineering charts (see Appendix D) to get a feeling for the required airflow rates, and therefore air package dimensions under different boundary conditions. Air hammer manufacturers are also providing respective engineering charts (see Appendix E).

Eq. 1[1] provides a correlation for gas volume requirements to ensure sufficient hole cleaning within vertical sections:

$$Q_{go} = 16.36\left({D_h}^2 - {D_p}^2\right) + 10^y - 100 \qquad \text{(Eq. 1)}$$

where

$$y = a_1 \log[\log(H + 10)] + a_2 R_p + a_3 \log\left({D_h}^2 - {D_p}^2\right) + a_4 \qquad \text{(Eq. 2)}$$

Q_{go} is the volumetric flowrate of gas at standard conditions [scf/min], D_h is the hole diameter [in], D_p is the drill pipe diameter [in], H is the vertical length [ft], R_p is the ROP [ft/h].

The values for the respective correlation coefficients can be found in Figure 32

Air injection pressure is dependent on air hammer requirements (manufacturer recommendations) plus the subsequent need to overcome a certain hydrostatic backpressure in case formation water influx is expected. (Halco Rock Tools Limited)

[1,2] Guo and Ghalambor 2005. *Gas volume requirements for underbalanced drilling: Deviated holes*. Norwood Mass.

Hole Size	a_1	a_2	a_3	a_4
Gas specific gravity 1.0:				
17 1/2"–15"	7.25460750	0.00252683	0.27678264	-1.76512350
12 1/4"–11"	6.66017330	0.00209705	0.19744638	-1.23402000
11"–9"	6.40820720	0.00192274	0.31610525	-1.32142100
9"–8 3/4"	6.27980630	0.00182764	-0.47922218	0.15480131
8 3/4"–7 3/8"	6.04554250	0.00168948	0.35335623	-1.18214840
7 3/8"–6 1/4"	5.67999600	0.00147466	0.29013093	-0.87638225
4 3/4"	4.95059100	0.00112253	-0.33060468	0.28730231
Gas specific gravity 0.8:				
17 1/2"–11"	6.78717390	0.00252877	0.21319786	-1.29000670
9 7/8"–7 7/8"	5.92049690	0.00188266	0.44937033	-1.21009550
7 3/8"–6 1/4"	5.50908860	0.00157407	0.23107964	-0.65470860
4 1/2"	4.69916450	0.00117097	-27.29631800	31.61369000
Gas specific gravity 0.6:				
17 1/2"–11"	6.58812640	0.00272353	0.18417591	-1.08519520
9 7/8"–7 7/8"	5.71924490	0.00201416	0.44615880	-1.05026580
7 3/8"–6 1/4"	5.33631670	0.00169377	0.22519935	-0.50772560
4 1/2"	4.55547190	0.00126530	-8.85095290	10.42734200

Figure 32: Correlation coefficients[2]

A very convenient and simple approach for a fist air volume estimation is to assume 900 to 1800 m/min uplift velocity as optimal for cuttings transport. The required air volume can be calculated by a very simple volumetric approach which is given by Eq. 3[1]. (Halco Rock Tools Limited)

$$x = \frac{v * (D^2 - d^2)}{1{,}305{,}096} \left[\frac{m^3}{min}\right] \qquad \text{(Eq. 3)}$$

Where x is the required air volume [m^3/min], D is the borehole diameter [mm], and d is the drill pipe diameter [mm].

<u>Connections and Trips</u>

During a connection, the underbalanced drilling system may become balanced since annular pressure may rise due to influx of formation fluids. This pressure increase stabilizes the system and pushes fluids back into the formation. To avoid swabbing effects, the compressors should be kept on until the drill pipe is within the slips. The best method to shut the pumps on or off is to do it stepwise to maintain the desired wellbore pressure. Pump rate and choke opening at the choke manifold are carefully adjusted to get the well to the desired pressure state. Trips into or out of the hole should follow proper connection procedures. Depending on downhole conditions, the wellbore can be left open or shut in against the RCD. Tripping speed should be reduced to not damage the sealing elements of the RCD. Generally, a fill-up of the borehole

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[1] Halco Rock Tools Limited. *A-Z of Drilling*, http://www.bospi.ch/download/HalcoAZofDrilling.pdf (accessed 27 June 2020).

with drilling mud is not necessary since the well pressure will be self-balanced. Careful surface pressure monitoring is needed in case formation gas is expected, and the installation of a downhole casing valve should be envisaged. For tripping back into the borehole, the choke at the choke manifold should be adjusted carefully to release excessive pressure and keep the borehole balanced. (Rehm 2012)

In case of pure air or mist drilling operations, it is important to circulate the hole clean before turning off the airflow to prevent cuttings pack off during connections. Pick up the drill string from the bottom and rotate it with the air package turned on, to clean the borehole. A constant circulating sub can be used to decrease connection times with air drilling. This sub allows for constant circulation during connections and therefore reduces downhole pressure fluctuations. (Rehm 2012)

Unloading of a Borehole

Unloading of a borehole full of water is necessary before the start of most gas drilling operations. Unloading is usually done with the drill string at the casing shoe. The compressor and booster of the air package should be turned on until booster pressure reaches near maximum. Start to pump water (mist or rig pump) until the pressure decreases and then stop the water pumping until booster pressure reaches near maximum again. Repeat this cycle until the compressor and booster pressure start to drop significantly, and the borehole is unloaded. Pumping of water into the drill string increases the density of fluid within the drill string and decreases the required booster pressure to unload the borehole. Following the unloading at the casing shoe the drill string is tripped further into the borehole and the unloading cycle repeats. This is done until the borehole is fully empty and the air drilling operation can continue. (Rehm 2012)

2.4 Percussion Drilling Systems

The following chapter deals with pneumatic (air hammer), hydraulic (water hammer), and hydraulic mechanical (axially oscillating downhole motor) percussion down the hole (DTH) drilling systems. A short introduction to the working principle of the different tools will be given where available operating parameters as well as advantages and disadvantages of the various technologies, will be discussed. Furthermore, an introduction to down the hole button bits will be given.

Percussion drilling systems for use in deep geothermal wells are so-called rotary percussion drilling systems, which is a hybrid form of pure percussion drilling and rotary drilling. Additional to the axially acting percussive hammering action, a rotation of the drill bit is enforced. Figure 33 shows the principle of the rotary percussive rock fragmentation process associated with combined percussion and rotary actions. The drill bit is forced into the rock by percussive action, while some shearing is introduced due to the rotation of the bit. A growing network of cracks is introduced to the rock by the hammering and shearing action. The bit rotates between every hammering cycle to impact fresh rock mass with the inserts and evenly crush the rock's surface. Depending on the hammering system, the produced rock powder and cuttings will be transported by the drilling medium (e.g., air, water, drilling mud) to the surface. (Song et al. 2018)

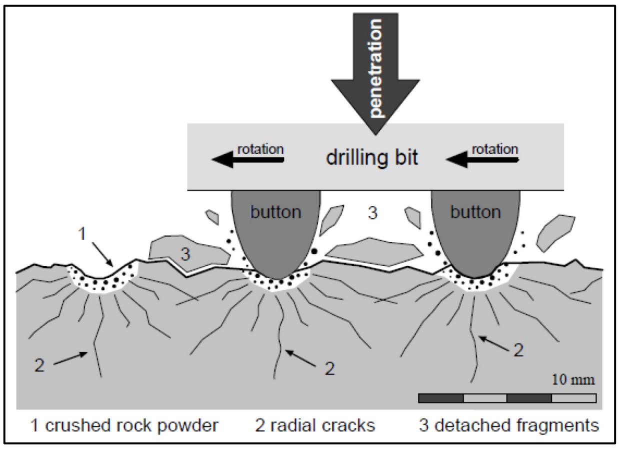

Figure 33: Cutting process typical for button bits used in rotary percussive drilling[1]

The main benefit of utilizing down the hole hammer systems is their relatively high ROP within hard and abrasive rocks while requiring low WOB and RPM compared to conventional rotary drilling using TCI bits. The reduced WOB and RPM can increase the life of drill string components due to less fatigue and reduced abrasive wear. Lower WOB reduces bending of the drill string and allows with the right BHA configuration (pendulum assembly) to reduce doglegs and drill vertical boreholes. Significant drawbacks are frequent mechanical failure of the hammer system, high gauge wear on button bits, difficulties in hole cleaning when using air only, no active directional control with most systems, no possibility to take surveys while drilling, poor drilling performance in soft rocks. (Melamed et al. 2000; Zacny and Bar-Cohen 2009; Vieira et al. 2011)

Rotary percussion drilling systems are of particular interest within crystalline basement drilling operations due to their high potential in significantly increasing ROP and run-length when compared to conventional hard rock rotary drilling. Different field studies and paper, some are referenced within Table 5, reported adequate achievements in the utilization of rotary percussion drilling systems.

[1] K. Thuro and G. Spaun 1996. *Drillability in hard rock drill and blast tunnelling*, https://www.researchgate.net/publication/293385972_Drillability_in_hard_rock_drill_and_blast_tunnelling.

Table 5: Percussion hammer performance overview

Geology/formation	Used system	Performance	Source
Medium-hard rock (limestone, sandstone with siliceous interlayers)	Reverse action-type hydraulic hammer (6.5/8” hole size)	Two to three times ROP increase compared to rotary drilling within comparable conditions (seven times faster when tested for same WOB and RPM).	(Melamed et al. 2000)
Igneous rocks (tuff, andesite, basalt, volcanic breccia)	Pneumatic hammer (17.1/2” to 8.1/2” hole size)	2.45 times increase in ROP and 6.42 times increase in run length compared to roller cone air drilling. The deviation was always kept below 2°.	(Zhao et al. 2018)
Conglomerate section (Oman)	Pneumatic hammer (8.3/8” hole size)	Section drilling time was reduced from approx. 29 to 5 days.	(Vieira et al. 2011)
Limestone, claystone, siltstone (Yemen)	Pneumatic hammer (26” to 12.1/4” hole size)	The average ROP increased from 9.25 m/h to 31.5 m/h when using air hammer instead of conventional drilling.	(Vieira et al. 2011)

2.5 Pneumatic Hammer (Air Hammer)

This chapter is going to deal with the basic design and operating principles of pneumatic hammer systems. Furthermore, operating parameters and best practices are discussed.

Two different air hammer designs are available. One design utilizes an annulus passage around the piston within the housing. Air flows through the annulus passage to the bit. The other design uses a control rod (feed tube) within the hammer center as a pathway for the compressed air through the hammer to the bit. The piston provides the hammering action which can reach, depending on the air volume and pressure, as well as air hammer architecture and subsurface boundary conditions, between 100 to 1,700 strikes per minute. Figure 34 shows the schematic of a control rod design. Within this schematic, the button bit shoulder does not touch the drive sub, which means the hammer is lifted off the bottom. In this mode, the compressed air can flow through the hammer without actuating the piston action. This mode is used for different operations, such as cleaning and unloading off the borehole.

To drill with an air hammer, weigh on bit needs to be applied. The applied weight forces the bit shank up inside the hammer housing until bit shoulder and drive sub are in contact. One of the piston ports is now aligned with one of the control rod windows. The compressed air now has a pathway to fill the space beneath the piston and cause an upward movement of the piston within the hammer housing. At the top of the pistons stroke, another piston port is aligned with a window within the control rod, now filling the space above the piston. This action causes the piston to move down again until it impacts the bit shank. During the upward stroke, no air exits the bit (approx. 0.050 seconds per cycle) while during the downward stroke, compressed air flows through the control rod towards the bit shank and the bit nozzles to the wellbore. (Lyons et al. 2016) The backpressure valve prevents flow of formation water through the hammer in case the air package is turned off. (Epiroc Drilling Tools AB 2018)

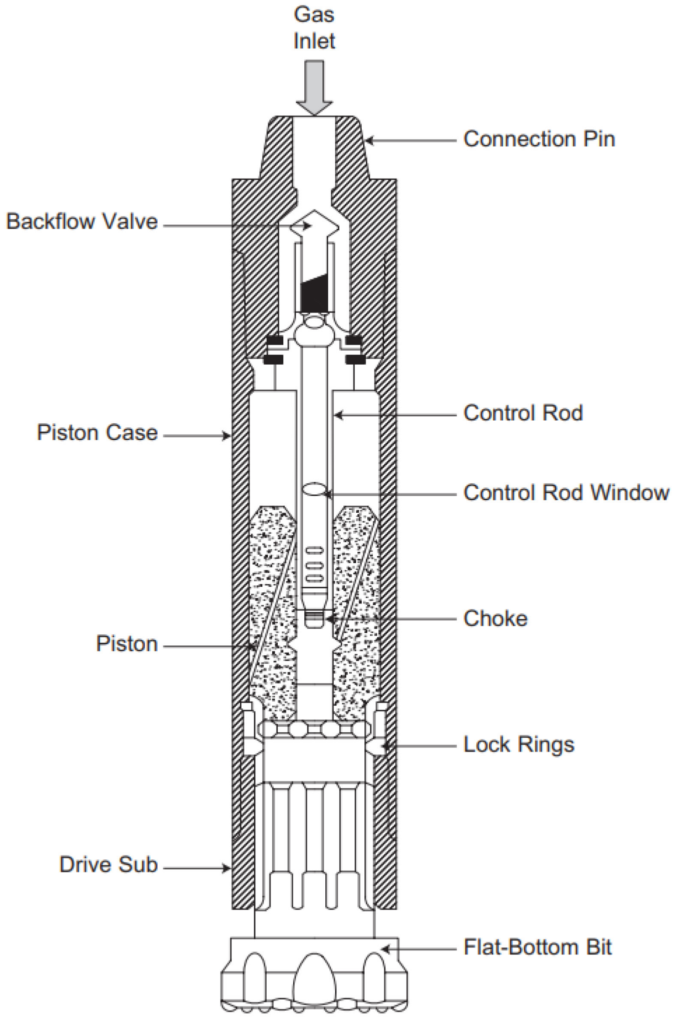

Figure 34: Air hammer schematic (control rod design)[1]

[1] Guo and Liu 2011. *Applied drilling circulation systems: Hydraulics, calculations, and models*. Amsterdam, Boston, Burlington, Mass.: Elsevier; Gulf Professional Pub.

A few basic rules should be followed to select the right air hammer for the intended drilling operation. The air hammer size should be close to the borehole size since the usage of an oversize bit with a small hammer will cause a significant performance drop. Furthermore, it should be envisaged to select the hammer, which is nearest to the maximum operating conditions of the chosen air package. A high hammer operating pressure brings excellent performance. (Lyons et al. 2016) Another important aspect is the selection of a suitable bit design, which is discussed in chapter 2.8.

Pneumatic hammers are prevalent for drilling vertical large diameter surface sections with little or no formation water influx. In such environments, the performance of a pneumatic hammer outdoes the performance of hydraulic hammer systems. However, pneumatic hammers are incredibly sensitive to backpressure (formation water influx) and show a higher diesel consumption per meter drilled when compared to a water hammer system for the same borehole size within the same formation. (Wittig et al. 2015) To ensure sufficient hole cleaning and support unloading of the well in case of formation water influx, unstable foam, or mist drilling in combination with an air booster should be used together with the pneumatic hammer. Active directional control is not possible with this system, which makes it only suitable for vertical well sections. Verticality of the borehole can be achieved by proper stabilizer placement (pendulum assembly) in combination with the low required WOB. (Beare 2019) Pneumatic hammer service life ranges between 3,000 to 5,000 m within very hard and abrasive formations such as granite. The hammer service life in abrasive formations is determined by wear on external components. (Halco Rock Tools Limited)

2.5.1 Pneumatic Hammer Operating Parameter and Best Practices

This chapter will give an introductory overview of recommended operating parameters (e.g., WOB, RPM, etc.) and best practices when drilling with a pneumatic hammer.

<u>Weight on Bit (WOB)</u>

The required WOB to reach optimal ROP with an air hammer depends on many factors and should be an onsite trial and error procedure. However, air hammer manufacturers deliver guidelines to select the right WOB for their systems. These methods can be used to get a first assumption on the required WOB, which aids within the detailed planning process.

For operating pressures below 17.2 bar, the bit diameter in millimeter should be multiplied with a factor of nine to get the WOB in kilograms. (Mincon Group Plc. 2014; Numa 2018)

For example:

Bit diameter = 16” (406.4 mm)

$$WOB = 406.4 * 9 = 3{,}657.6\ [kg] \sim 3.6\ [t] \qquad \text{(Eq. 4)}$$

For operating pressures above 17.2 bar, the bit diameter in millimeter should be multiplied with a factor of 14 to get the WOB in kilograms. (Mincon Group Plc. 2014)

Table 6 shows the recommended WOB for an air hammer with a 6.1/2” button bit from another manufacturer.

Table 6: Recommended WOB for a 6.1/2” bit diameter (Epiroc Drilling Tools AB 2018)

Air pressure (bar)	Feed force (kN)	Feed force (lbs)
10	7	1570
15	10	2250
20	14	3150
25	17	3820
30	20	4500

Proper WOB selection is important during air hammer drilling, since too low WOB may result in bit bouncing, button pop out and bit shank failure. Too high WOB may cause hole deviation and uneven or stopped bit rotation. (Mincon Group Plc. 2014; Epiroc Drilling Tools AB 2018; Numa 2018)

<u>Rotating Speed (RPM)</u>

The selection of a proper rotational speed (RPM) depends on many factors, such as the bit and bit button type, formation characteristics, and air hammer type. Selected RPM influences the bit wear and hammer performance. Again, manufacturers give recommendations for optimum RPM selection.

Eq. 5[1] gives a mathematical formula depending on the strokes per minute, button, and bit diameter to select proper RPM. The manufacturer states that this method usually overestimates the RPM. (Epiroc Drilling Tools AB 2018)

$$RPM = \frac{SPM * Button\ diameter}{Bit\ diameter * \pi}\ (\pm 15\%\ depending\ on\ formation\ and\ bit\ type) \qquad \text{(Eq. 5)}$$

Where SPM are the strokes per minute, $Button\ and\ Bit\ diameter$ are in millimeter.

A very rough estimation of RPM can be obtained by dividing 300 by the bit diameter in inches. (Epiroc Drilling Tools AB 2018)

For example:

Bit diameter= 16”

$$RPM = \frac{300}{16} = 18.75\ [\frac{rev}{min}] \qquad \text{(Eq. 6)}$$

[1] Epiroc Drilling Tools AB 2018. *Secoroc COP M6 down-the-hole hammer: Operator’s instructions, Spare parts lists*, 2018.

Figure 35 shows another method to select proper RPM. Uneven wear as visible within the specified illustration indicates that RPM was selected too high. (Epiroc Drilling Tools AB 2018)

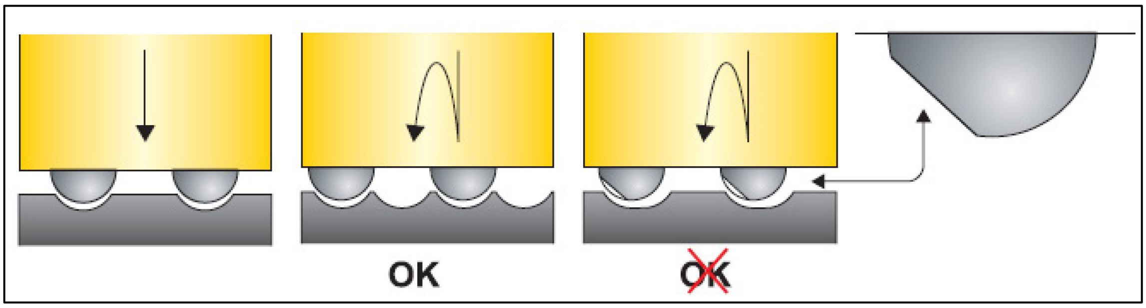

Figure 35: Method to determine adequate RPM (uneven wear at the bit buttons)[1]

Another manufacturer suggests using Eq. 7[2] to select RPM accordingly.

$$RPM = 1.6 * ROP \qquad \text{(Eq. 7)}$$

Where ROP is the rate of penetration in meter per hour.

The most accurate way to select the RPM accordingly to the selected WOB is to allow 12 to 16 mm of penetration per revolution. This can be measured with a piece of chalk during the drilling operation. However, generally, RPM lies between 25 to 35 RPM for most operations. It is known that the harder the formation and the larger the drill bit, the slower the RPM. (Mincon Group Plc. 2014)

Over rotation can have a significant effect on bit wear, especially in very hard and abrasive formations. Excessive wear of the outer carbide inserts (gauge loss) is a common phenomenon. (Mincon Group Plc. 2014) Too slow rotation causes a recrushing of rock mass (regrinding), leading to rapid button wear. (Numa 2018)

Lubricating Oil Consumption

The importance of adequate air hammer lubrication cannot be overemphasized. Inadequate lubrication will lead to rapid wear of internal parts and subsequent failure of the air hammer. The right lubricating agent needs to be chosen depending on manufacturer statements and boundary conditions. Environmentally friendly edible oils (e.g., vegetable oils) may also be used. As a rule of thumb, around 1 ml of rock drilling oil per m^3 of consumed air should be the minimum dosage. Higher dosages are needed when foam or mist drilling is performed. For an

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[1] Epiroc Drilling Tools AB 2018. *Secoroc COP M6 down-the-hole hammer: Operator's instructions, Spare parts lists*, 2018.

[2] Numa 2018. *Technical Manual*, 2018, https://www.numahammers.com/wp-content/uploads/2016/05/Tech_Manual.pdf.

adequate supply of oil to the air stream, two systems are mainly used. Plunger pumps and venturi (nozzle type) lubricators. (Epiroc Drilling Tools AB 2018)

Figure 36 and Figure 37 show the oil consumption individual air hammer manufacturer recommend for their products. For mist drilling, the oil dosage should be increased by 50% when adding 3.8 liters per minute of water to the air stream and by 100% when adding 7.6 liters per minute of water. (Mincon Group Plc. 2014)

Hammer	Rock Drill Oil Volume Required	Hammer	Rock Drill Oil Volume Required
3” - 4”	1 qt/hr (1 L/hr)	12”	5 qts/hr (5 L/hr)
5” - 6”	2 qts/hr (2 L/hr)	18”	10 qts/hr (10 L/hr)
8”	3 qts/hr (3 L/hr)	24”	16 qts/hr (15 L/hr)
10”	4 qts/hr (4 L/hr)	33”	20 qts/hr (19 L/hr)

Figure 36: Recommended oil dosage for Numa pneumatic hammer[1]

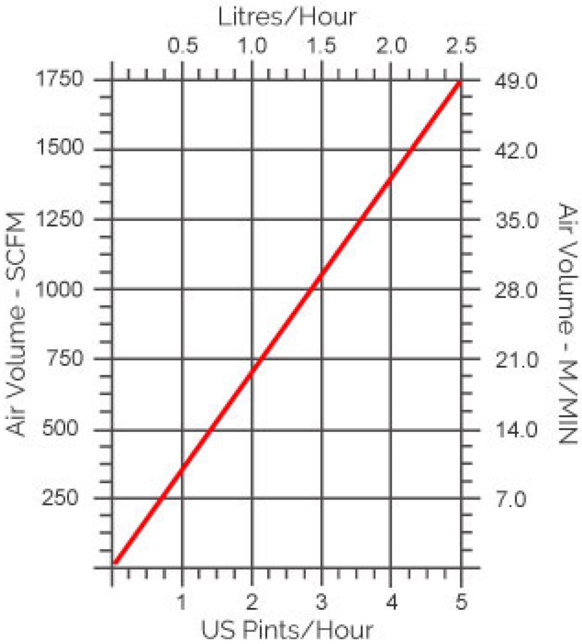

Figure 37: Oil consumption of Mincon pneumatic hammer[2]

Mist and Foam

Foam and polymers can be used with a pneumatic hammer to improve hole cleaning and unloading of the well in case of formation water influx. Furthermore, foam polymer mixtures may form a sort of filter cake on the borehole wall to stabilize the formation and inhibit clay swelling. (Numa 2018)

A blend of 0.5 to 2% of a foaming agent within water is advised. The water injection pump (mist pump) needs to have a high-pressure rating since the foam will be directly injected into the high-pressure air stream. (Epiroc Drilling Tools AB 2018) It is advised to add a temperature

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[1] Numa 2018. *Technical Manual*, 2018, https://www.numahammers.com/wp-content/uploads/2016/05/Tech_Manual.pdf.

[2] Mincon Group Plc. 2014. *Operation & Service Manual: Mincon MP240 DTH Hammer*, 2014.

tolerant viscosifier like PAC R or Xanthan, together with a foaming agent, to the freshwater before foaming. (Litke 2019)

2.6 Hydraulic Hammer (Water Hammer)

The main advantages of hydraulic hammer compared to pneumatic hammers are the lower energy consumption per meter drilled (related to energy losses within air compressors), the negligible effect of formation water influx and backpressure on hammer performance and therefore no theoretical depth limitation, oil-free application, and reduced drill pipe and borehole erosion due to reduced circulation velocities. Drawbacks are their sensitivity to solids within the drilling fluid (extremely pure water at high quantities required) and their restricted availability for large borehole sizes (> 12.1/4” nominal borehole size). (Wittig et al. 2015; Homuth et al. 2016) Table 7 shows a selection of commercially available water hammers.

Table 7:Selection of commercially available water hammer systems

DTH Water Hammer (Market overview with focus on the European market)		
Company	**Country**	**Hole size**
Drillstar Industries SAS	France	6” – 8.1/2”
Wassara	Sweden	2.3/8” – 10”
DrillKing International L.P	USA	Not specified
Chang Shin	South Korea	3.3/4” – 10”
Hanjin D&B	South Korea	up to 12.1/4”
Epiroc	International	up to 12.1/4”

Hydraulic hammer can be classified according to their mechanic operating principle. Three main groups, namely direct-acting, indirect-acting, and dual-acting hydraulic hammers, will be discussed in more detail. (Wittig et al. 2015)

The direct-acting hydraulic hammer (Figure 38, left side) has the most straightforward operating architecture. When the striking piston moves towards the anvil to create the hammering action at the bit, hydraulic fluid can flow through the piston and anvil to the bit. Following the strike, the piston is pushed upwards against the valve, closing the fluid flow path. This builds up hydraulic pressure and causes to repeat the cycle. (Hartrusion 2020) The most significant drawback is the limited spring lifetime. (Wittig et al. 2015)

The reverse acting hydraulic hammer (Figure 38 middle) utilizes a valve within the anvil. Hydraulic fluid can flow to the bit during the downstroke action of the hammer. The striking piston pushes the valve towards the anvil, which closes the valve. The hydraulic pressure keeps the valve closed and pushes the striking piston upwards until the valve gets opened by the upward movement of the striking piston. The stored spring energy will now force the piston downwards again. (Hartrusion 2020)

The dual-acting hydraulic hammer (Figure 38 right side) works without the utilization of any springs. This makes this architecture the most durable and only commercial available hammer. (Wittig et al. 2015) A small orifice within the anvil combined with a large piston front creates a pressure differential, which will move the striking piston upwards towards the valve. This can only be achieved because the backside of the piston is connected to the well annulus. High differential pressures and lower flow rates are required for operation since the piston needs to push the hydraulic fluid through a small nozzle within the anvil during the downstroke. (Hartrusion 2020)

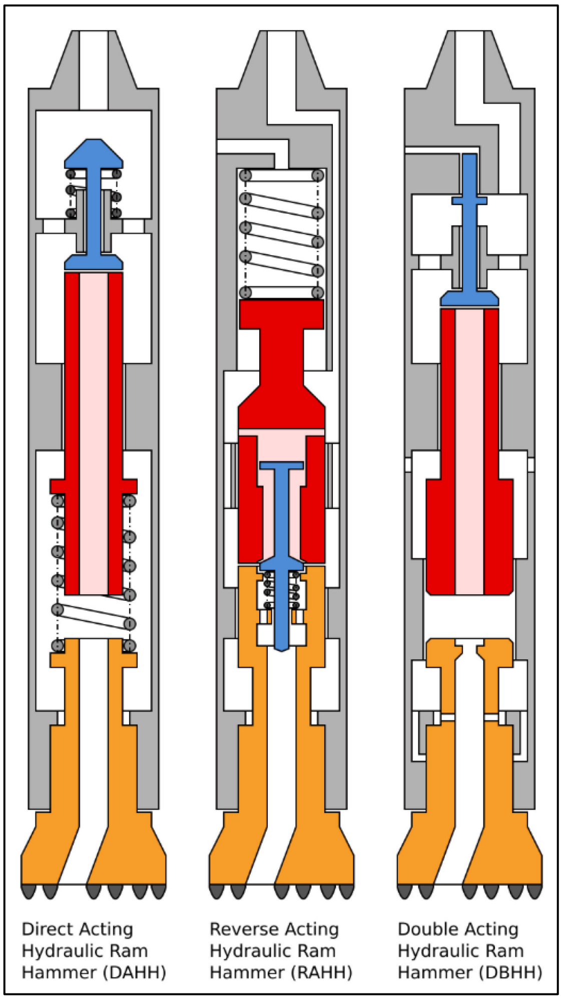

Figure 38: Hydraulic hammer mechanism and designs (blue: valve, red: piston, orange: anvil and bit)[1]

2.6.1 Water Hammer Operating Principles

The operational surface system and equipment for water drilling and conventional rotary drilling utilizing mud as a drilling fluid are comparable, which is why this is not within the scope of this

[1] 2020. *Hydraulic Percussion Hammer Drive Mechanisms | Hartrusion*, 28 May 2020, https://hartrusion.com/en/hydrdthhammer/drivemechanisms/ (accessed 28 May 2020).

thesis. This chapter will discuss special requirements that come along with hydraulic hammer drilling. Solid control is a very delicate thematic and will, therefore, be discussed in more detail.

Water Consumption and Hole Cleaning

Water consumption of a water hammer is dependent on the type of hammer and is available for every hammer over the manufacturer. Figure 39 shows the water consumption and pressure required to operate an 8" water hammer able to drill 8.1/2" to 10" boreholes. Higher flow rates and pressures are necessary for harder and more competent rocks.

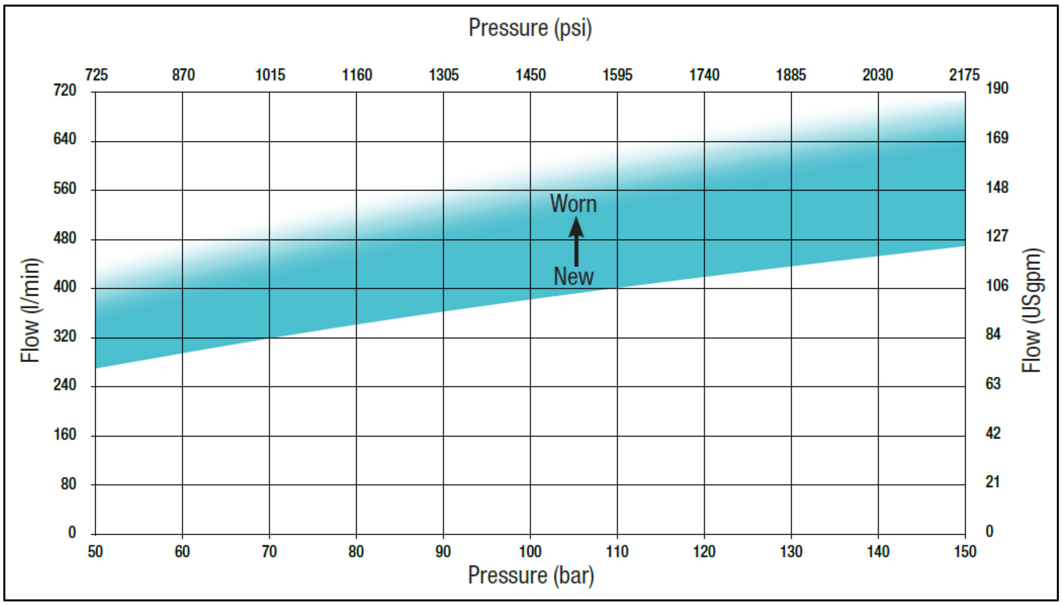

Figure 39: Water and pressure consumption of an 8" water hammer (boreholes from 8.1/2" to 10")[1]

Depending on the borehole size and hammer type, water flow through the hammer and the bit may not be sufficient for adequate hole cleaning. Therefore ROP needs to be controlled, or the actual drilling needs to be stopped from time to time to flush the hole clean. (Wittig et al. 2015) Additional bypass valves may be used to direct some of the drilling water directly to the annulus to get a higher annular cutting transport velocity and allow for sufficient hole cleaning.

Pulsation Dampener

Caused by the discontinuous working principle of the water hammer, significant pressure variations within the feed water arise. These pressure variations have the potential to damage mechanical components and the water pumps. The solution for these pressure variations is the installation of a pulsation dampener (flexible element) installed to the feedwater line. This pulsation dampener should decrease positive and negative pressure peaks and allow for smooth operations. (Göran 2004)

[1] Wassara 2020. *W200 Hammer*, 11 June 2020, https://www.wassara.com/products/hammer/W200/ (accessed 11 June 2020).

2.6.1.1 Solid Control System

The major disadvantage of hydraulic hammers is theis high requirements on the purity of water. This makes water treatment allowing recirculation of used water a vital topic. Depending on the used system and manufacturer specifications, the number of dissolved solids should be as low as possible. One source reports approximately 0.015 % with a desirable maximum grain size of 20 microns. (Wittig et al. 2015) Other sources report a maximum allowable solid content of 50 mg/l with grain sizes not exceeding 50 microns. No more than 0.1% of weight share is acceptable for an abrasiveness of the particles comparable to gneiss. Up to 220 mg/l are acceptable for other water hammer systems. (Nordell et al. 1998; Göran 2001; Wittig et al. 2015) Literature clearly shows that there are different requirements, depending on many parameters. However, generally, manufacturer recommendations should be followed, and the amount of solids and particle grain size should be kept as low as technically possible within the water hammer feed water.

Depending on the extent of the drilling operation (depth and borehole size), freshwater supply capabilities at the site, water hammer requirements, and disposal requirements, different water cleaning systems can be used.

One setup for drilling with a 6” water hammer with a flowrate of 36 m^3/h (600 l/min) consisted of a first stage gravity cleaning container with a sedimentation container and filter system to remove coarse cuttings. A second stage lamella cleaning container, in combination with a flocculation unit, was added to the first stage. A very fine 5-micron filter run at the very end left a rather clean liquid ready to be reused within the water hammer. To allow sufficient feed of the 6” water hammer operated under full flow, the lamella sedimentation cleaner needed a size of approximately 60 m^3. Running a complete solid control system including shale shaker, desander, desilter and centrifuges would be possible but is very expensive. (Wittig et al. 2015)

A very cost-effective and functional system for a water cleaning system is illustrated in Figure 40. The system is based on gravity sedimentation (lamella cleaner) for the primary cleaning process. This is supported using a flocculent (e.g., polyacrylamide) to cause clumping of very fine particles, which then are separated from the clean water within the lamella cleaner. The system is assisted by hydro cyclones to provide further fluid cleaning if necessary. A safety filter with a filter size of 10 microns is recommended before the high-pressure fluid pump to avoid damaging the pump or the water hammer. (Göran 2001) It is important to monitor and evaluate possible feedthrough (l/min) and the accompanying pressure drop for designing filter sections.

Another way for effective feed water filtration would be the implementation of cartridge filter systems, as for example dual pod filters. Various systems with different filter cartridges, able to filter particles as small as 0.5 micron from a feedwater stream, are available on the market. It is recommended to prefilter the water using hydro cyclones or comparable, before leading the water stream through the filter system to avoid premature clog up of the filter cartridges. The filter system can be implemented in series or parallel, depending on the onsite needs. The water stream can be diverted towards standby filter pods in case filter cartridges need to be changed. This allows smooth operations without service interruptions. (Pro-T 2020; Slomp 2020) The dual pod combi filter unit “TDW 610-50/40-4B” supplied by Baker, is able to use filter cartridges with a micron rating of 0.5 to 50 while handling a flowrate of 2383 l/min. (Bakker Oildfield Supply Coevorden B.V 2020)

The incorporation of desander and desilter systems, as well as centrifuges into the water cleaning system proposed within Figure 40, needs to be investigated in more detail. It is not within the scope of this thesis.

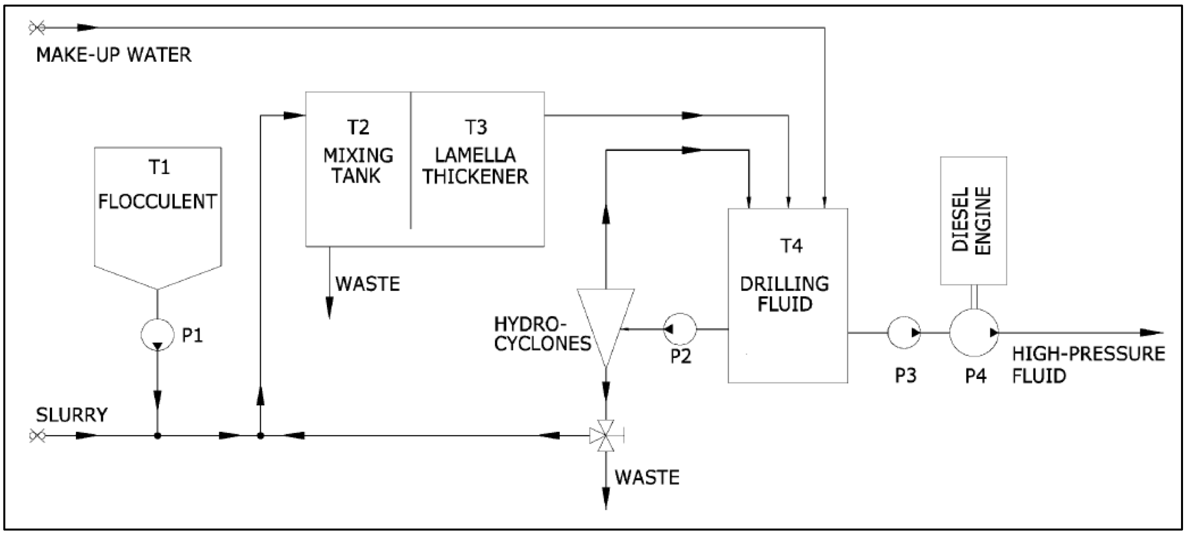

Figure 40: Schematic setup of a proposed water cleaning system for water hammer fluid recycling[1]

Figure 41 shows the schematic of a lamella clarifier. These lamella clarifiers exist in different sizes and architectures. Figure 42 shows part of the water purifying system (sedimentation and lamella cleaner) utilized by Hanjin during drilling a 5,000 m deep borehole with an 8” water hammer in crystalline basement rock (granite). (Wittig et al. 2015)

[1] Tuomas 2004. *Effective use of water in a system for water driven hammer drilling*. *Tunnelling and Underground Space Technology:* 69–78. https://doi.org/10.1016/j.tust.2003.08.0011.

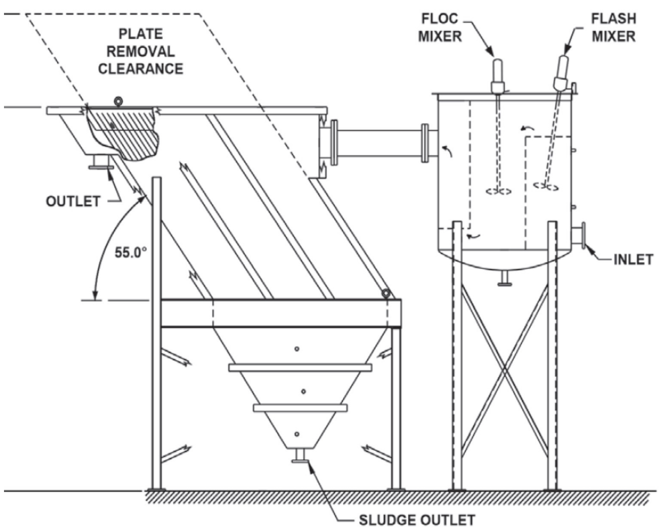

Figure 41: Schematic of a lamella cleaner with preceding floc mixer[1]

Figure 42: Cutout of the sedimentation and lamella cleaning system used by Hanjin[2]

2.7 Hydraulic Mechanical Hammer

Another option for rotary percussive basement drilling would be the utilization of a hydraulic mechanical hammer system or comparable, which allows for higher ROP´s within very hard formations such as granite and provides directional control abilities. The fluid hammer, such as the one supplied by NOV available for hole sizes from 6” up to 26” (NOV 2020), will be implemented into a conventional BHA with a power section (downhole motor) to drive the hammer. It is essential to differentiate this type of hammers from down the hole pneumatic or hydraulic hammer. The fluid hammer provided by NOV utilizes the torque supplied by the downhole motor to create axial hammer forces. It may be implemented with both, roller cone as well as fixed cutter bits. No special restrictions on mud type exist. It I recommended to keep the abrasiveness of the drilling fluid low, as recommended for every motor. (Erdwerk GmbH 2020g)

2.8 Down the Hole Button Bits

Conventional roller cone or PDC drill bits are not suitable for percussive drilling. Therefore, special down the hole button bits are used with air or water hammer systems. Figure 43 shows main components of a downhole button bit.

[1] Graver Water Systems. *Lamella Clarifier: Datasheet*, https://graver.com/pretreatment/lamella/ (accessed 11 June 2020).

[2] Wittig et al. 2015. *Hydraulic DTH Fluid / Mud Hammers with Recirculation Capabilities to Improve ROP and Hole Cleaning For Deep, Hard Rock Geothermal Drilling*.

The top of a button bit is called the anvil. This is the part that is struck by the hammer piston to create the hammering action. The bit chuck needs to be compatible with the selected air or water hammer system. The bit face may be concave, convex, or flat, depending on the formation to be drilled. Gas grooves are manufactured into the bit face to allow the drilling fluid to move to the annulus and transport cuttings to the surface. Rounded tungsten carbide inserts are found at the bit face. (Rehm 2012)

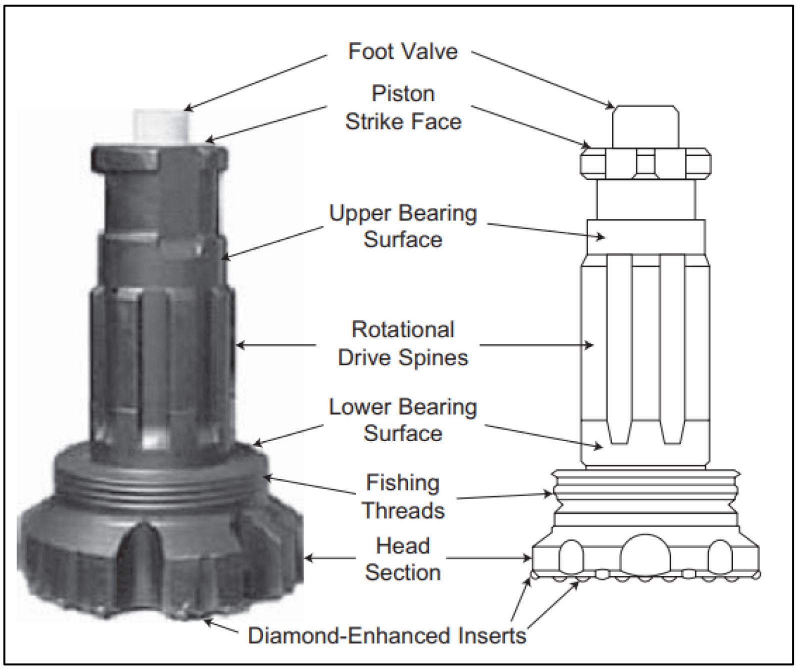

Figure 43: Schematic of a flat bottom button bit[1]

Proper bit selection can increase ROP and bit service life. The bit design should be suitable for the drilled formation. Figure 44 gives an overview of bit face designs and their suitability for certain rock abrasiveness and hardness. Step gauge, as well as double gauge and flat face bits, are best suited for drilling in very hard and abrasive crystalline basement. (Lyons et al. 2009)

[1] Guo and Liu 2011. *Applied drilling circulation systems: Hydraulics, calculations, and models*. Amsterdam, Boston, Burlington, Mass.: Elsevier; Gulf Professional Pub.

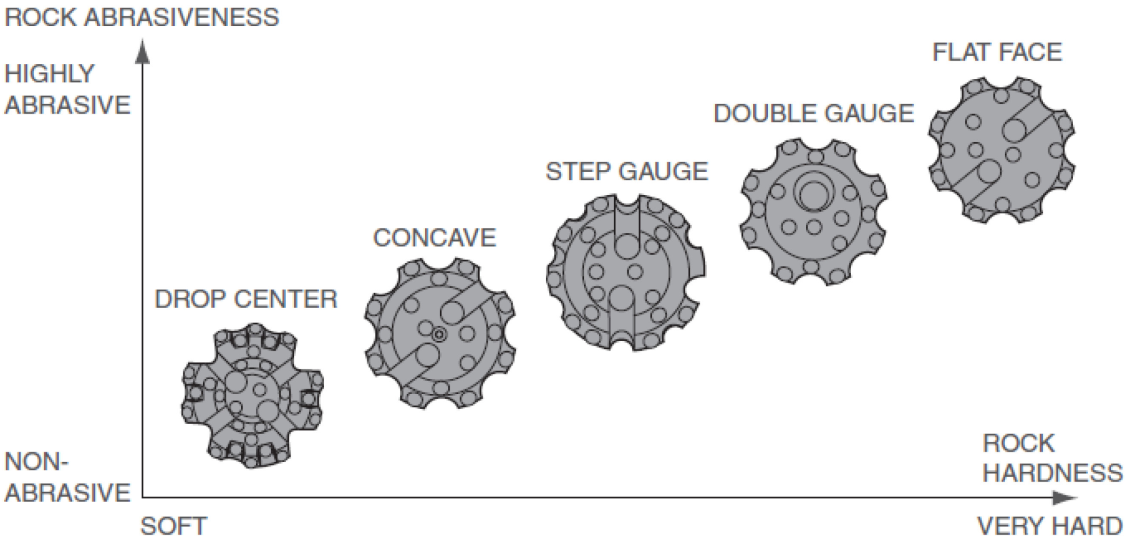

Figure 44: Downhole button bit face design for rock abrasiveness and hardness[1]

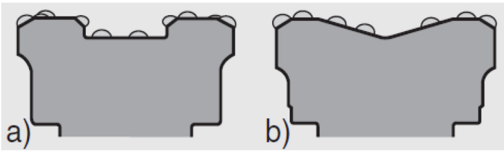

Figure 45: Bit face profiles: a) drop center bit and b) concave bit[2]

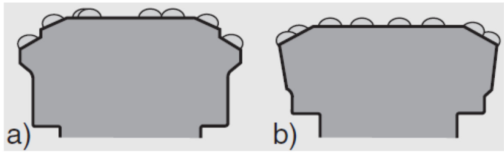

Figure 46: Bit face profiles: a) step gauge bit and b) double gauge bit[3]

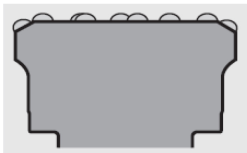

Figure 47: Bit face profiles: flat face bit[4]

A common problem of downhole button bits is their strong tendency for gauge loss. It is common to step down a borehole. This means that a section will be started with a specific button bit size, and the next run bit will have a reduced diameter by usually 1/8" (approx. 3 mm). This allows to avoid time-consuming reaming jobs. (Rehm 2012) It is important to keep this in mind when planning a well since the borehole diameter at the end should be suitable to run the indented casing string and allow for a successful cementing operation. Gauge protection features as discussed for roller cone bits within chapter 2.2.1.1 are applicable for downhole button bits as well.

[1,2,3,4] Lyons et al. 2009. *Air and Gas Drilling Field Guide: Applications for Oil and Gas Application for Oil and Gas Recovery Wells and Geothermal Fluids Recovery Wells*, Third Edition. Elsevier.

The buttons at the hammer drill bit should be re-grinded when ROP starts to decrease or when any of the carbide buttons are damaged. This can be done utilizing special machines on site. (Epiroc Drilling Tools AB 2018)

3 Practical Work and Methodology

The following chapters guide through the decision process concerning which technology to utilize within the planned project. Furthermore, the proposed surface and subsurface air hammer setup will be detailed to act as a basis for tender documents as specified within the scope of this thesis. Detailed technical knowledge and expertise were mainly gained during expert interviews with specialized companies and experts within the field of down the hole hammer drilling. Lastly, the model setup for the probabilistic time estimation, as well as the setup of the economic analysis comparing the air hammer and rotary drilling approach, are discussed. Main topics include:

- Project overview
- Drilling method selection process
- Evaluation of critical technical components and interfaces for the functional integration of an air hammer system in combination with a conventional drilling rig
- Introduction of the probabilistic time estimation model to compare air hammer and conventional drilling for the same project
- Economic analysis based on the time estimation

3.1 Project Details

Relevant project details, essential for the comprehensibility of the thesis, can be found in the following sections. The basement geology, as well as the planned well design, including trajectory and borehole size, have an impact on the selected drilling method. Therefore, a thorough overview of the geological setting, as well as the planned well design, is given. To guarantee data protection and the integrity of the ongoing project, the thesis is referencing a fictive project based on actual project data.

3.1.1 Introduction

The investigated project aims to exploit a hydrothermal reservoir located in fissured crystalline rocks (gneiss) by a single producer well. The objective is to pump thermal water from the highly fractured aquifer (high secondary permeability due to fractures) to produce electricity with an Organic Rankine Cycle (ORC).

3.1.2 Site Geology

The geothermal resource targeted by the project consists of deep-water flows that occur in the frontal part of a crystalline massif. This massif is made up of gneiss, migmatites, granites, and amphibolites of Proterozoic to Palaeozoic age. The foliation of the gneisses is generally strongly inclined, but also intensely folded. A graben with Carboniferous and Permian clastic filling, all forming an "anti-Triassic base" are incorporated into the regional geology. A reduced sedimentary cover of Triassic to Tertiary age covers this complex. (Erdwerk GmbH 2019b)

Table 8: Lithological sequence along the well path[1]

0 - ~5 m MD	Artificial storage: Sandy-silt fill with blocks up to 50 cm in size (tunnel excavation materials)
5 - 50 m MD	Quaternary: Sandy-silty gravel with large blocks incorporated as well as alluvial and fluvial deposits.
50 – 3,300 m MD	Outer massif: Crystalline basement containing alternating fissured granitic gneiss, rich in quartz and darker magmatic gneiss with biotite and chlorite. Amphibolite lenses are possible. Data is available up to a depth of about 600 m (offset well). Below, an extrapolation based on the outcrops in the region was carried out.

3.1.2.1 Expected Temperatures

From the surface to 300 m TVD, mixing with cold water of the nearby river groundwater and the slope of the valley causes rapid cooling of the rising geothermal water. Between 300 and 2,300 m TVD, the temperature of the geothermal water in the permeable fractures is expected to rise from 70°C up to a maximum of 125°C. Locally the temperature of the water can vary depending on the distance to an open and conductive fracture system. Within the fractured reservoir from 2,300 m up to 3,000 m TVD, geothermal fluids are expected to rise rapidly, allowing for a homogeneous reservoir temperature with a maximum of 125°C. Figure 48 illustrates the external temperature profile used for calculations regarding the well design. (Erdwerk GmbH 2019a)

[1] Erdwerk GmbH 2019b. *Geological Details for the Technical Planning: Unpublished Document*. Munich, 2019.

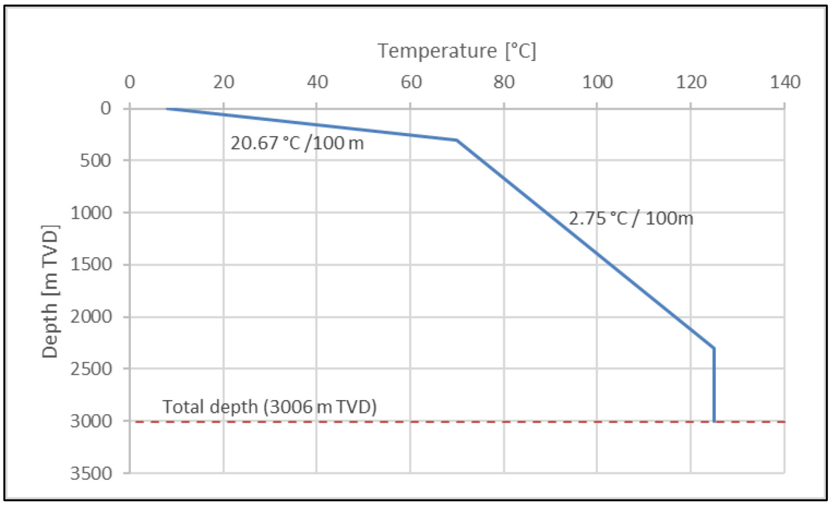

Figure 48: Expected temperature profile used for calculations regarding the well design[1]

3.1.2.2 Geological Challenges

The geological boundary conditions at the project location are extraordinary and bare risks and challenges that were accounted for within the well design. A combination of potential loss of circulation zones with the scenario of a gas bearing sedimentary layer proved to be a challenge to find a suitable well design for the exploratory geothermal well.

Table 9 shows a summary of the most prominent identified challenges and risks which were considered for the well design and the detailed drilling program.

Table 9: Overview of selected identified risks [2]

Depth [m TVD]	**Stratigraphy**	**Geological risk/challenge**	**Technical implication**
50 – 3,000	Massif (paragneiss, orthogneiss, granite, amphibolite)	Minor to total mud losses caused by faults/open fractures (high hydraulic permeability)	May lead to a bad or even no cutting discharge, and further to a stuck drill string and a subsequent twist off. If a fishing job is not successful, a partial or total loss of the BHA and the section may be the consequence. Further: • dry run of casings • blind drilling (well control issue) • bad cementation due to cement losses into the formation

[1] Erdwerk GmbH 2019a. *Drilling Program-Geothermal Well: Unpublished Document*. Munich, 2019.

[2] Erdwerk GmbH 2019. *Risk Matrix: Unpublished Document*. Munich, 2019.

	Massif (paragneiss, orthogneiss, granite, amphibolite)	Loosened and grated rock within the immediate area of the faulted zone	Stuck pipe events are potentially leading to a partial or total loss of the BHA and section.
1,500 to 3,000		Over pressured zones (17 bar artesian)	Shut-in of the well and increase of the mud weight should allow continuing drilling. Difficult to handle in combination with loss of circulation zones (kick loss scenario)
600 – 3,000		Presence of gases	Associated hydrocarbon gases (e.g., methane) Gas influx during any blind drilling operation leading to an unnoticed gas kick. The presence of gas during setting of cement may lead to channelling and, therefore, a bad cement sheath.
50-3,000		Stress Field and Borehole instability (Borehole breakouts)	Breakouts may lead to borehole instabilities and into a subsequent stuck drill string. If a potential fishing job is not successful, partial or total loss of the BHA may be the result. Breakouts may lead to large cavities and washouts, which in turn could lead to an insufficient cement job. Trapped annular fluids may lead to annular pressure build-up (APB), which may lead to a casing collapse. Uncemented sections of casing may lead to buckling or collapse of the casing string during the production phase.
		Hard and abrasive crystalline formation with a high quartz content	Quick bit wear and low ROP with a subsequent frequent required bit change. Undetected bit gauge loss due to abrasiveness of the formation may lead to lengthy and time-consuming reaming works. High unfiltered quartz content within the drilling fluid. May lead to fast erosion of sensitive BHA components leading to severe damage beyond repair (DBR) cost. Quick wear of rotary steerable system (RSS) pads (push the bit system) expected. May lead to a loss of directional control. Quick wear of stabilizers may lead to high vibrations and damage to the BHA.
		Dipping Formation/Oriented Minerals	Deviation from the desired well path. Corrections may cause high doglegs and increase the torque while drilling. Difficulties in running casing or liner strings may arise.

2,500 to 3,000	Mesozoic Sediments	Influx of gas (up to 90 bar overpressure)	Shut-in of the well and increase of the mud weight should allow continuing drilling. Difficult to handle in combination with loss of circulation zones, which might lead to an underground blowout (kick loss scenario).

It is of uppermost importance to understand that there were far more risks and challenges considered for the well design and detailed planning. However, to evaluate all of them lies not within the scope of this thesis. The above-indicated risks are included in this thesis to provide full comprehensibility.

3.1.3 Planned Well Design

The following tables and figures are intended to give a detailed overview of the planned well design. The well design is influenced by many parameters, such as geological boundary conditions (pore and fracture pressure gradient) and the targeted production rate. Since the planned well is regarded as an exploratory well, the design is very flexible due to starting the first section with a relatively large hole size. This allows to react in the case of unforeseen events while still being able to reach the planned total depth with the desired hole diameter.

Table 10 shows a summary of well design specifications. Since drilling within the crystalline basement excludes the risk for swelling shales, the fluid design can be kept relatively simple. It is intended to drill the well with a water polymer drilling fluid in case of rotary drilling and foamed and misted air in case of pneumatic percussive drilling, keeping the mud weight as low as reasonably possible to avoid excessive mud losses (see risks in chapter 3.1.2.2). (Erdwerk GmbH 2019a)

Table 10: Well design specifications overview[1]

	MD [m]		**TVD [m]**		**Hole-Ø**	**Mud Type**	**Cementation**
	from	**to**	**from**	**to**	**inch**		
Line Pipe	0	55	0	55	880 mm	-	-
1. Section	55	1,000	55	1,000	23”	Water Polymer/Foam	Two-Stage Cementation
2. Section	1,000	1,800	1,000	1,800	16”	Water Polymer/Foam	Two-Stage Cementation
3. Section	1,800	2,640	1,800	2,500	12.1/4”	Water Polymer	Two-Stage Cementation
4. Section	2,640	3,310	2,500	3,006	8.1/2”	Water Polymer	(Optional 4-Plug Liner Cementation)

[1] Erdwerk GmbH 2019a. *Drilling Program-Geothermal Well: Unpublished Document*. Munich, 2019.

Figure 49 and Figure 50 show the directional well path. The well path for the 3rd and 4th section was planned to intersect as many fractures as possible to maximize formation water inflow during the production phase.

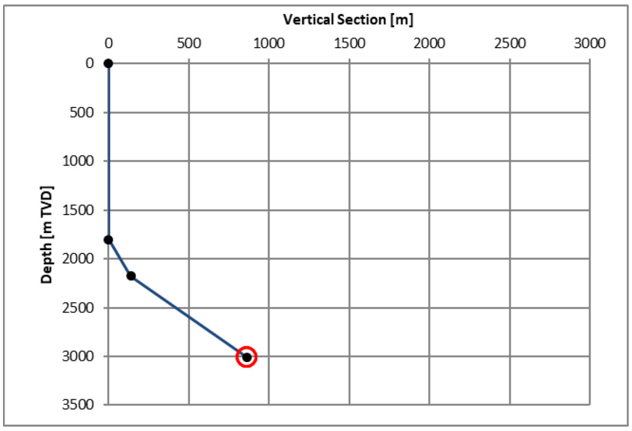

Figure 49: Vertical section[1]

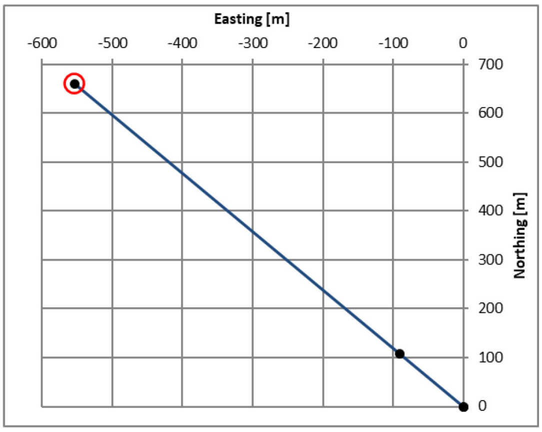

Figure 50: Plan view[2]

Figure 51 visualizes most relevant technical and geological parameters within a well schematic. On the left-hand side, the lithological column, as well as the two expected reservoirs, are visualized. It is planned to drill the 3rd section and conduct well tests to check the productivity of the well. If well productivity is satisfying to meet the required project financials, the drilling operations will be stopped, and the 3rd section will be completed for production. If the test results are not as expected, the well will be further deepened to a well depth of 3,000 m TVD (3,300 m MD) to reach the secondary target. With regards to the possibility of a combined production from the 1st and 2nd target, it is planned to leave the 9.5/8" liner within the 3rd section partially uncemented. This prevents excessive cement migration into the reservoir and might allow using the 1st target as a fallback option. The right-hand side of the well schematic shows the planned completion. The production tieback will be left uncemented to allow a lateral movement within the polished pore receptacle of the 13.3/8" liner. This completion method avoids wellhead growth and excessive compressional forces during the production of hot geothermal water.

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[1] Erdwerk GmbH 2019a. *Drilling Program-Geothermal Well: Unpublished Document*. Munich, 2019.

[2] Erdwerk GmbH 2019a. *Drilling Program-Geothermal Well: Unpublished Document*. Munich, 2019.

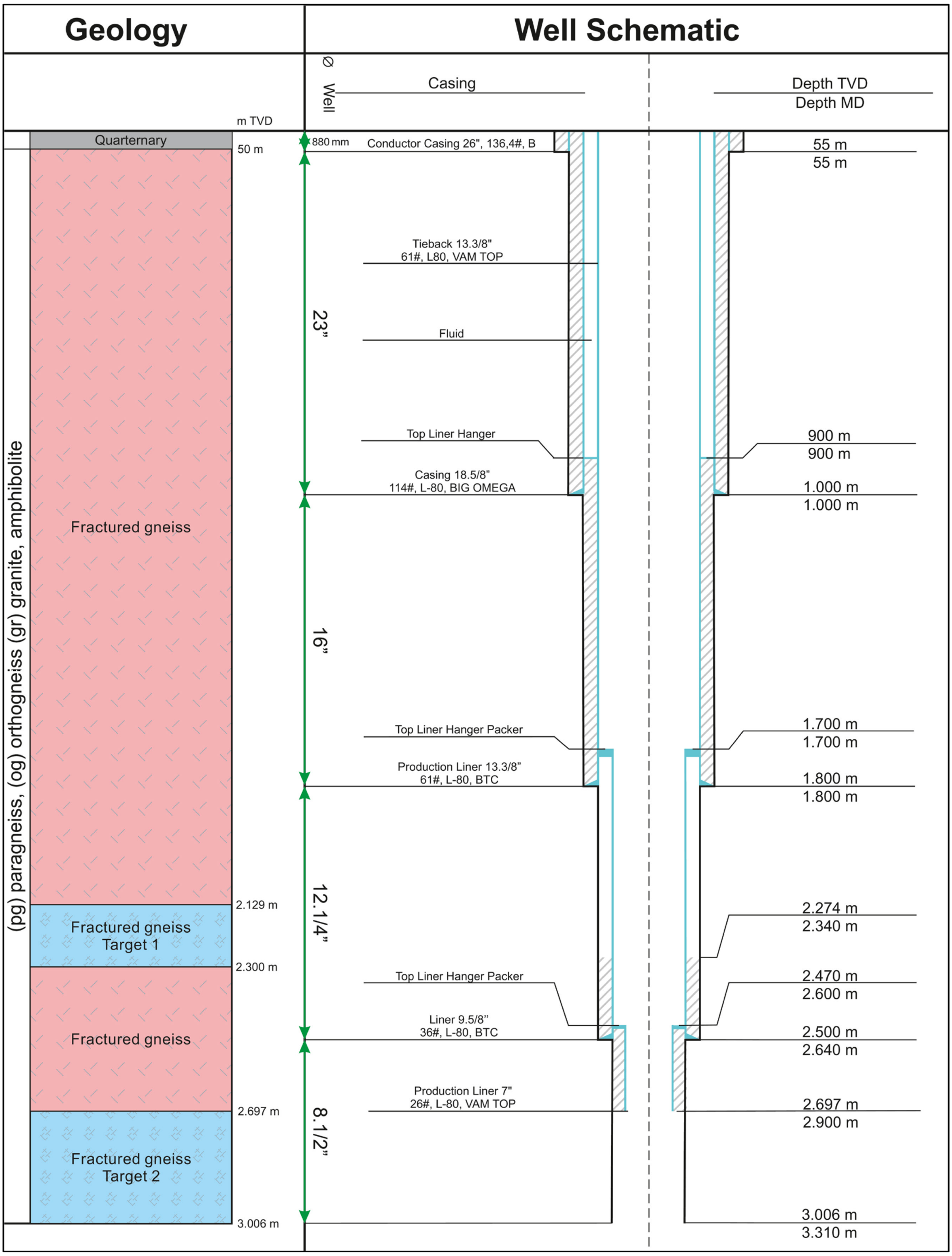

Figure 51: Schematic of the planned geothermal well[1]

[1] Erdwerk GmbH 2019a. *Drilling Program-Geothermal Well: Unpublished Document*. Munich, 2019.

3.2 Drilling Method Selection Process

The drilling technology selection process was carefully done based on project boundary conditions and industry expertise. Knowledge was gathered by expert interviews (phone calls, e-mails, face to face meetings) to be able to select the optimum technological setup for the planned project.

The plan foresaw to conduct detailed planning as well as tendering for both options, conventional rotary drilling, and percussive rotary drilling (pneumatic or hydraulic). The key points from the selection process, including challenges and solutions, are discussed within the following chapter.

3.2.1 Pneumatic vs. Hydraulic Hammer

A detailed overview of the planned project, including a well schematic and planned completion, can be found within chapter 3.1. As can be obtained from the well schematic, it is intended to keep the first two sections fully vertical. As already thoroughly discussed during the fundamentals part of this thesis, currently available percussive hammer systems (pneumatic and hydraulic) allow for no active directional control. However, adequate stabilizer placement aided by low required WOB should allow keeping the wellbore trajectory vertical. This high-level setup was recommended by industry experts (Lackner 2019; Beare 2019). Taking this into account, it was decided to utilize a percussive hammer for the fully vertical first and second sections. Hydraulic operated hammers (water hammers) have many advantages compared to pneumatic hammers (air hammers). Higher efficiency (energy consumption per meter drilled), ability to handle high rates of formation water influx, no need for extensive surface system adaptions when compared to the adaptions necessary for air hammer drilling (e.g., foam unit, air manifold, air package, etc.), are some of the advantages which are also discussed within the fundamentals part of the thesis. Unfortunately, market research (see Table 7) confirmed manufacturer expertise about the non-existing availability of water hammer systems for nominal borehole sizes of 23” and 16”, this left air hammer systems as the only remaining option to conventional hard rock rotary drilling.

It is essential to keep borehole stability issues in mind when planning operations utilizing air hammer systems. Major concern is the removal of a stabilizing drilling fluid column within the borehole. Based on the very low density of air or foam, compared to water or mud, the stabilizing backpressure on the formation is minimal. Knowledge of the regional geology with particular focus on subsurface stress states is critical to assess if the application of the air hammer system is applicable. Within this project, borehole stability issues are not expected to arise in depths shallower than 1,700 m TVD. A more thorough analysis could be conducted but is not within the scope of this thesis. Casing design of the surface casing, which will be in place when drilling the second section, needs to be carefully checked for the adopted load cases (zero inside backpressure for a worst-case scenario). In this case, no issues with the casing stability are expected after a detailed review considering the changed input data for the drilling fluid.

The expected artesian conditions with the accompanying formation water influx provide by far the highest challenge for air hammer drilling. This could be confirmed by industry experts who have proposed to use the air hammer system in combination with drilling foam to remove formation water from the borehole. The intention is to keep the back pressure on the air hammer as low as reasonably possible. (Lackner 2019; Beare 2019) The use of foam for air hammer drilling creates another challenge. The drilling site of the planned project is very limited in size, which implicates that no large blow or storage pits for returned foam handling can be utilized. Problem description, along with possible solutions, can be found in chapter 2.3.1.3. The expected challenges can be handled from an engineering point of view. No major issues were detected during the initial planning phase, leading to the decision that the air hammer system may be a feasible option in contrast to conventional hard rock rotary drilling within gneiss.

3.3 Air Hammer Setup

The following chapter will give a detailed overview of the planned air hammer system.

3.3.1 Operating Parameter

A rough operating parameter estimation will be given in this chapter. Required air flowrate and pressure are discussed in section 3.3.2.

WOB

Methods and explanations concerning WOB selection for air hammer drilling can be found within chapter 2.5.1.

Following the WOB estimation procedure proposed within chapter 2.5.1 for operating pressures larger than 17.2 bar and nominal button bit sizes of 23” (584.2 mm) and 16” (406.4 mm), an approximate WOB of 8.2 t for the 23” section and 5.7 t for the 16” section could be obtained, respectively. However, these are only first estimations. Values should be carefully rechecked on site together with all involved parties and especially the air hammer manufacturer.

Keeping the WOB within the often very tight operational window of the air hammer provides a significant challenge during the drilling operation, especially in deviated borehole sections as drag needs to be considered. (Schindler 31.07.20)

RPM

Methods and explanations concerning RPM selection for air hammer drilling can be found within chapter 2.5.1.

The RPM estimation is based on the formula proposed within Eq. 5. Following assumptions are made:

Bit button diameter = 22 mm for the 23” bit and 20.5 mm for the 16” bit (Numa 2020a, 2020b)

Strokes per minute (SPM) = approx. 900 SPM for the first section hammer and 1150 SPM for the second section hammer (Numa 2020a, 2020b)

The results following the different approaches presented within Eq. 5 to 7 in chapter 2.5.1 are summarized in Table 11.

Table 11: Calculated expected operational air hammer RPM

	Approach with Eq. 5 [RPM]	Approach with Eq. 6 [RPM]	Approach with Eq. 7* [RPM]
1. Section	10.7	13.0	12.8
2. Section	18.5	18.8	16.0

* Estimated ROP 8 m/h and 10 m/h for the first and second section, respectively.

A cross-check between the different assumptions shows that the calculation results are all within reasonable ranges. Estimations for the first section air hammer range from 10.7 to 13 RPM, while estimates for the second section air hammer range from 16 to 18.8 RPM. However, these are only first estimations. Values should be carefully rechecked on site together with all involved parties.

3.3.2 Air Package and Surface Systems

The following chapter intends to elaborate the minimum requirements for necessary surface equipment. The performed calculations and estimations are based on knowledge gathered during the literature review phase of the thesis. The calculated and stated minimum requirements aid in the selection of suitable surface equipment for the specified project. The performed economic analysis will be based on selected equipment fulfilling the minimum technical requirements stated within this chapter.

Air Flowrate and Pressure

Exact flowrate and pressure calculations are not within the scope of this thesis and could be part of possible future work. Models and approaches to be followed can be found within literature (Guo and Ghalambor 2005). However, manufacturer statements, engineering charts (see Appendix D), as well as the correlation presented within chapter 2.3.1.4, are considered to be able to pre-select an adequately sized air package for the planned project. Prices for the pre-selected air package will be considered for the economic analysis. Final selection of the air package will be made together with all involved parties at a later point within the project.

It is essential to understand that the expected formation water influx and subsequent use of foam are profoundly impacting the required air package flowrate and pressure capabilities.

The considered assumptions are summarized in Table 12.

Table 12: Summarized Input Parameter

	DP Size [inch]	Expected ROP [m/h; ft/h]	Section TD [m; ft]	Gas Specific Gravity [s.g]
1. Section (23” Nominal Size)	6.5/8	8; 26	1,000; 3,280	0.8
2. Section (16” Nominal Size)	6.5/8	10; 33	1,800; 5905	0.8

Unfortunately, no correlation coefficients are available within literature for the 23” borehole size of the first section. Inserting the stated input parameter into Eq. 1 and Eq. 2 within chapter 2.3.1.4, yields 141 m^3/min (4,965 scf/min) required for optimum cutting transport while drilling the second section.

No engineering charts are available for the 23” nominal borehole size within the first section. Assumed required air flowrate for drilling of the 16” second section can be obtained as 164 m^3/min (5,800 scf/min) from Figure 103. However, volumetric requirements within the second section are not determined by the 16” open hole section, but rather by the 17.755” ID of the 18.5/8” surface casing.

Utilizing the volumetric approach presented in Eq. 3 and estimating the optimum uplift velocity to be 1350 m/min (mean value of the given range from literature), the air volume required for the first section is calculated to be 324 m^3/min (11,441 scf/min). The air volume needed for the second section is estimated to be 181 m^3/min (6,391 scf/min). Following the approach presented within Eq. 3 provides the most accurate solutions, which could be confirmed by industry expertise. (Erdwerk GmbH 2020h) This is why the values obtained following the approach presented within Eq. 3 will be considered for the air package design. Furthermore, values obtained from engineering charts (available for drilling the second section only, see Figure 103) seem to be reliable when comparing results following the approach presented in Eq. 3 and the engineering chart.

Air hammer tend to be extremely sensitive towards backpressure exerted from the hydrostatic head of formation water within the borehole. The recommended air hammer operating pressure should be provided downhole. If a manufacturer states that the optimum operating pressure for the air hammer is 20 bar, then an air package rated to 50 bar should be used to operate the air hammer in a depth of 300 m TVD (30 bar hydrostatic backpressure) assuming a borehole filled with fresh water. (Halco Rock Tools Limited)

Based on the assumed formation water influx, an experienced air hammer manufacturer stated 300 m^3/min (10,500 scf/min) rated to 80 bar (consisting of 25 – 30 bar rated compressors and a booster rated to at least 100 bar) as a requirement for the first section. (Erdwerk GmbH 2020h) This recommendation would confirm the volumetric approach presented in Eq. 3 to be valid for first estimations regarding the required air volume.

Considering the recommendations of the air hammer manufacturer, the selected compressors should have a pressure rating of 25 to 30 bar, and the booster should be rated to at least 100 bar. Compressors can be operated in parallel mode, which is why the flowrate produced by every compressor can be summed up. It is essential to carefully select the booster based on the processable input flowrate and input pressure and the subsequent output flowrate and pressure. The booster should ideally work with the output pressure of the compressors. These considerations are taken into account for the air package pre-selection.

Air Package Requirements

To meet flowrate and pressure requirements, the air package should consist of compressors with a pressure rating of 25 to 30 bar, able to deliver a combined air volume of 300 m^3/min. The booster should be able to process 300 m^3/min and elevate the input pressure up to 100 bar.

A possible air package able to fulfil the estimated requirements in terms of pressure and flowrate could be the following:

8 x Y35 Stage IV – Oil-injected air compressor (diesel driven) from Atlas Copco with max. capacity of 39.8 m^3/min at 25 bar and 35.4 m^3/min at 35 bar. Diesel consumption under full load 94.5 l/h/compressor.

3 x B18TT-62-3000 – Containerized Air Booster (diesel driven) from Atlas Copco able to process 127 m^3/min of inlet air at 34 bar pressure and produce 100 bar outlet pressure (acting as single stage). Diesel consumption under full load 145 l/h/booster.

Datasheets for the selected air package equipment can be found within Appendix F – Air Package Datasheets.

A summary of the required air package is represented in Table 13.

Table 13: Air package summary

	Quantity	Output of Full Package	Diesel Consumption [l/h/piece]
Y35 Stage IV Compressor	8	318.4 m^3/min at 25 bar and 283.2 m^3/min at 35 bar	94.5
B18TT-62-3000 Booster	3	381 m^3/min at elevated pressures up to 100 bar*	145

* Depending on the input air pressure.

It is planned that specialized service personnel from the air package equipment provider is on site to assemble the equipment and instruct the rig crew. The rig crew will handle the operation of the air package. (Erdwerk GmbH 2020h)

3.3.3 Additional Surface Equipment

This chapter lists further necessary surface equipment to establish a functional air hammer drilling system. A detailed description of the mentioned equipment can be found in chapter 2.3.1.2 and chapter 2.3.1.3. Major equipment forming an integral part of the system will be detailed, other equipment to establish a functional system such as valves, gauges, and connection lines are essential, but will not be described within this thesis.

The chronology of the following equipment list pictures the air path from the air package (compressors and booster) towards the standpipe, down the hole to the air hammer, and discharge of the air/foam and cuttings through the RCD and blooie line towards the solid control system (refer to Figure 30).

Air Volume and Pressure Recorder

The air volume and pressure recorder is located within the air flow line directly following the air package in front of the mist pump. The recorder should be able to work with the anticipated volumes and pressures (e.g., 300 m^3/min at 100 bar).

Mist/Foam System

Consideration of using misted air or even foam for drilling the planned project are explained within chapter 2.3.1.3 and chapter 2.3.1.4. Main intention is to be able to unload the hole from expected formation water influxes and allow adequate cutting transport.

Required equipment consists of freshwater tanks with enough capacity to support continuous misted/foamed air drilling. The size of the freshwater tanks depends on the available freshwater supply on site. The freshwater tanks will be filled continuously and should act as a buffer. Further, a mixing tank, including mixing impeller, is required to allow blending of polymers (e.g., PAC R, PAC L, or Xanthan), high-temperature foaming agent (e.g., Foam-Star GT), and freshwater. The required mist pump should be finely adjustable and have adequate volume and pressure ratings for the expected conditions. The necessity for a foam generator needs to be evaluated during the operations on site.

The impact of air drilling additives consumption on project financials will be investigated within a separate chapter.

Air Manifold

It should be located at or near the rig floor to allow fast redirecting of the air stream during, e.g., connections. The air manifold should be rated for the expected pressures and volumes.

RCD (Rotating Control Device/ Rotating Head)

The RCD forms an integral equipment part of air drilling operations. It is discussed in chapter 2.3.1.2.

The first section will be drilled without a BOP in place. Usually, the RCD is mounted on the top flange of a potential annular preventer. In this case, the service of welding a suitable flange with an adapter flange on top of the conductor casing, to allow a connection to the RCD API bottom flange needs to be performed. Due to the expected artesian conditions of maximum 17 bar, the RCD specifications depict a minimum of 300 psi (20.7 bar) dynamic pressure rating at 100 RPM. The outlet to the flowline (blooie line) should be as large as possible to avoid annular back pressure on the air hammer. A possible RCD would be the model 9000 from Weatherford. It comes with the following specifications: (Weatherford 2012-2015)

- 500 psi dynamic pressure rating at 200 RPM
- 13.5/8” API bottom flange
- 9” bore through the bearing assembly (compare with 6.5/8” FH Tool Joint OD of 8.5”)
- 7.1/16” flowline connection (blooie line)

Taking this data into account, an adapter flange from, e.g., 30” (weld-on the conductor) towards 13.5/8” (RCD bottom flange) should be provided. The welding and mounting works, including the provision of the specified flange, will be included in a lump sum position for the economic analyses. The second section will be drilled with a mounted BOP reflecting industry standards and considering the expected pressure scenarios. The annular BOP will most likely come with a 20.3/4” or 21.1/4” top flange. Again, an adapter flange from 20.3/4”/21.1/4” towards 13.5/8” will be necessary. It is essential to closely monitor the total BOP installation height, including adapter flange and RCD height, since the hole construction needs to fit under the rig floor.

Blooie Line

The blooie line connects the RCD with potential surface retention and storage pits or the solid control system.

Referring to chapter 2.3.1.2 (Blooie line), the optimum diameter can be obtained by multiplying 1.1 times the annular cross-section of the top hole (23” borehole, 6.5/8” DP). Following this approach, the optimum blooie line diameter is calculated to be 11”. However, RCD outlet size is limited to 7.1/16”, which is why it was decided to use an 8” blooie line. A crossover from the 7.1/16” RCD outlet to the flange of the 8” blooie line will be required. Furthermore, the blooie line will be equipped with a sample trap (for mud logging), a torch, and a defoamer injector for accelerated foam degradation on surface (see Figure 31). The blooie line may be rotated following every bit change to evenly distribute erosion and avoid blooie line failure. (Erdwerk GmbH 2020f)

Air Drilling Separator (Cyclone)

Due to the limited size of the drilling site, the utilization of blow pits for returned cutting and fluid collection is not possible. These makes the use of an air drilling separator, as explained in chapter 2.3.1.2 necessary. The air drilling separator is a very robust and straightforward designed piece of equipment. Its sole purpose is to separate the high-velocity discharge air and cutting stream following the blooie line. High fluid stream velocities exceeding up to 70 m/s combined with abrasive gneiss cuttings cause astonishingly high erosion rates, which is why the blooie line and air drilling separator should be designed to withstand these conditions (e.g., thick walls, erosion-resistant inner coating, design avoiding sharp bends and edges).

(Erdwerk GmbH 2020f) The separator needs to be designed to deal with significant amounts of produced formation water. Following the separator, a connection to the rigs solid control system is envisaged for sufficient fluid cutting separation and reduced cutting disposal cost.

3.3.4 Subsurface System Setup

The subsurface system (BHA) design for air hammer application is rather simple and consists mainly of the appropriate air hammer with suitable button bits for the respective section. Furthermore, bypass valves, vent/chokes, string stabilizer, shock subs, and suitable drill collar and heavyweight drill pipes are amongst equipment required for a successful air hammer operation. (Halco Rock Tools Limited; Reif 2020)

The main challenges are hole cleaning and assuring the verticality of the borehole within foliated gneiss. The BHA setup proposed in Table 14 is recommended by industry experts. Verticality will be achieved by applying the pendulum principle with adequate stabilizer placement. The low required WOB utilizing the air hammer technology implicates low BHA bending and, therefore, less tendency to go off vertical when compared to rotary drilling within the crystalline basement.

Bypass valves are used to divert drilling air towards the annulus, bypassing the air hammer, to assist in hole cleaning in case the air volume rating of the intended air hammer is not sufficient to guarantee efficient hole cleaning. It is crucial to design the bypass valve in a way to allow an optimized air hammer operation. If the valve bleeds off too much air towards the annulus, air hammer efficiency may be significantly impacted, leading to reduced ROP and subsequent long drilling times.

Table 14: Air Hammer BHA proposal modified after (Reif 2020)

DTH Air Hammer BHA (Pendulum principle)		
	1. Section (23”)	**2. Section (16”)**
	Description	**Description**
Drill Pipe	6.5/8”	6.5/8”
HWDP	6.5/8”	6.5/8”
Cross Over	x	x
Drill Collar	8.1/4” Nominal size (1 - 3 pcs.)	8.1/4” Nominal size (1 - 3 pcs.)
Cross Over	x	x
Shock Sub	9” Nominal size	9” Nominal size
Drill Collar Spiral	9.1/2” Nominal size (1 - 3 pcs.)	9.1/2” Nominal size (1 - 3 pcs.)
String Stabilizer	22.1/2” Nominal size	17,19”
Drill Collar Spiral	9.1/2” Nominal size (1 - 3 pcs.)	9.1/2” Nominal size (1 - 3 pcs.)
Downhole Hammer	E.g., Numa P185	E.g., Numa P185

DTH Hammer Bit	DTH Hammer Bit with Stabilizer (23”)	DTH Hammer Bit with Stabilizer (17,24”)

Since drilling in abrasive crystalline basement strongly affects gauge of DTH button bits, a so-called step-down process is often used to avoid time-consuming reaming operations. The projects envisaged drill bit program as proposed by industry experts can be found within Table 15.

Table 15: Downhole button bit program modified after (Erdwerk GmbH 2020f)

1. Section (23”)			**2. Section (16”)**		
Bit Size [in, mm]	**From [m]**	**To [m]**	**Bit Size [in, mm]**	**From [m]**	**To [m]**
23.03, 585	55	205	16.54, 420	1000	1150
22.91, 582	205	355	16.42, 417	1150	1300
22.80, 579	355	505	16.30, 414	1300	1450
22.68, 576	505	655	16.18, 411	1450	1600
22.56, 573	655	805	16.10, 409	1600	1750
22.44, 570	805	1000	16.02, 407	1750	1800

6.5/8” Drill pipes are envisaged for the project in face of the hard and abrasive formation and therefore high demand on the drill pipes. Furthermore, necessary uplift velocity can be easier achieved with 6.5/8” drill pipes due to a reduced annular cross-sectional area, compared to 5.1/2” drill pipes within a 23” open hole.

3.4 Rotary Drilling Setup

This chapter of the thesis deals with the conventional rotary drilling setup planned as a base case for the project. An overview of the recommended operational parameter for efficient basement drilling founded on industry expertise is given. Furthermore, promising BHA configurations, including the vital topic of drill bits, are discussed. It must be acknowledged that the character of this thesis is very exploratory and project-specific, causing that little related published literature is available. The bulk of the gained knowledge and information is retrieved from numerous expert interviews conducted throughout the development of this thesis.

3.4.1 Operating Parameter

Some general guidelines for operating parameters (pump rate, WOB, RPM) are given in this chapter. The information displayed within this chapter was consolidated from the following sources, which are mainly expert interviews (Erdwerk GmbH 2020a, 2020b, 2020c, 2020d, 2020e). Since optimum operating parameters need to be determined on-site together with all involved parties knowing exact BHA and bit configuration (e.g., drill off test), the guidelines provided within this chapter are only for planning purposes and may be subject to significant change. The general guidelines for RPM and WOB strongly depend on the selected bit technology, especially if impregnated bits or TCI bits are to be utilized. For impregnated bits, high RPM and low WOB values are to be envisaged. However, impregnated bits are not within the focus of this thesis. The following recommendations are based on the utilization of TCI bits (IADC 645 or 647). The general recommendation is to use high WOB and low RPM to achieve acceptable ROP and limit abrasive bit and BHA wear. In case a downhole motor is utilized for directional control, the setting should be suitable for low RPM and high torque (high lobe configuration).

WOB

23” TCI bit approx. weight on bit will range between 30 t up to 50 t depending on selected BHA and exact bit type.

16” TCI bit approx. weight on bit will range between 20 t up to 40 t depending on selected BHA and exact bit type.

12.1/4” TCI bit approx. weight on bit will range between 10 t up to 30 t depending on selected BHA and exact bit type.

8.1/2” TCI bit approx. weight on bit will range between 5 t up to 20 t depending on selected BHA and exact bit type.

RPM

It should be kept below 100 RPM for all sections. Optimum RPM to be determined by drill off tests on site. 60 to 80 RPM are envisaged according to offset data and expert interviews.

Pumping Rate

The optimum pumping rate for every well section was determined based on the planned mud system and borehole geometry, as well as cutting size and cutting particle density to provide optimum hole cleaning and hydraulic power at the bit. (Erdwerk GmbH 2019a).

3.4.2 BHA Configuration

This chapter discusses possible BHA configurations for basement drilling. Most configurations were elaborated together with industry experts from different directional drilling companies. However, the detailed engineering phase will be entered at a later stage. The described reference BHA within this chapter will act as the basis for the directional drilling assembly used within the economic analysis. The costs incurred will be compared to the costs incurred by an air hammer BHA for the same sections. A more thorough explanation of mentioned BHA components with a special focus on hard rock drilling may be found within Appendix C.

Main challenge is to optimize ROP while extending bit run lengths (limiting abrasive wear on BHA components and the bit) and keeping the borehole vertical within the first two sections. As already explained within chapters 2.1.1.3 and 3.1.2, the encountered gneiss is expected to cause BHA to drift off the vertical, caused by the foliated nature of gneiss. Furthermore, the high planned WOB to optimize ROP (especially when drilling with TCI bits), will cause bending of the BHA and increases the tendency to go off vertical. This leads to the planning decision that a stabilized BHA as for the air hammer BHA is not sufficient for drilling vertical when conducting standard rotary hard rock drilling. The initial option to establish vertical sections is to utilize measures for active directional control. The options are to use a vertical RSS or a conventional directional assembly consisting of a downhole motor (e.g., PDM) with a bent sub. These BHA assemblies allow to take corrective measures if the well path goes off vertical.

Expert interviews, as well as own expertise, confirmed that the usage of an RSS system might not be economically viable for the planned project. This is caused by high day rates applicable for RSS systems as well as high redress and repair costs when compared to conventional directional drilling assemblies. It is expected that there will be no or minor increase in ROP when utilizing a vertical RSS for the planned project. (Erdwerk GmbH 2020b, 2020c) This fact affirmed the decision to plan for a DHM with bent sub to drill the first two vertical sections allowing to perform corrective slides in case needed.

Rig time is one of the main cost drivers within a drilling project. To optimize the economic performance of a planned project, strategies, and options to optimize the drilling process, as well as BHA handling times, should be sought. One option to significantly reduce BHA handling times during necessary trips, caused for example by the necessity for a bit change, would be to reduce the utilization of drill collars within the BHA and increase the usage of heavyweight drill pipes instead. This has the potential to reduce BHA handling times since HWDP´s can be racked back without the need for lifting subs. However, the effect on BHA stiffness and potential buckling issues, especially in the case of high required WOB, needs to be closely investigated during the detailed BHA planning phase. (Erdwerk GmbH 2020a, 2020b, 2020c)

Geothermal projects often require large hole sizes (especially for the top hole section) to be able to exploit the reservoir with a large enough hole size to limit pressure loses and enhance the hydraulic performance of the well, as well as allowing to place large production pumps (e.g., ESP´s) able to produce the envisaged production rates for the economic viability of the project. However, large diameter sections require high flowrates to provide adequate hole cleaning. The requirement for high flowrates to meet the hydraulic requirements and the simultaneous request for low RPM when utilizing TCI bits (see chapter 3.4.1) bears some challenges. A high lobe configuration is envisaged. However, the highest lobe configuration for applicable downhole motors lies between 0.02 up to 0.03 rev/liter. This implies that with a flowrate of 4,000 l/min, already 80 to 120 RPM are produced at the motor (excluding string RPM). Exceeding the recommended RPM range will eventually lead to premature bit wear. Possible solutions would be the use of bypass subs or nozzled rotors, allowing some of the volumetric flow to bypass the power section of the motor and assist in hole cleaning only. Nozzled rotors are preferred since the hydraulic energy can still be utilized at the bit, while a bypass sub would divert some of the volumetric flow directly towards the annulus. A third possibility would be to decrease the flowrate since hole cleaning may not be complicated given the low ROP and small cutting size (almost powder). (Erdwerk GmbH 2020a, 2020c)

The following BHAs are planned for within the first two vertical sections of the well. The depicted setups represent the planning phase and may be subject to significant change during further detailed planning.

Table 16: Planned conventional directional drilling BHA´s for the first two sections

Rotary Drilling BHA (Conventional Directional Drilling)		
	1. Section (23”)	**2. Section (16”)**
	Description	**Description**
DP	6.5/8” Nominal Size	6.5/8” Nominal Size
HWDP	6.5/8” Nominal Size	6.5/8” Nominal Size
Cross Over	x	x
DC Spiral	8.1/4” Nominal Size (3 pcs.)	8.1/4” Nominal Size (3 pcs.)
Cross Over	x	x
Accelerator	optional	optional
DC Spiral	9.1/2” Nominal Size (3 pcs.)	9.1/2” Nominal Size (3 pcs.)
Jar	9.1/2” Nominal Size	9.1/2” Nominal Size
DC Spiral	9.1/2” Nominal Size (2 pcs.)	9.1/2” Nominal Size (2 pcs.)
Stabilizer	22.1/2” Nominal Size	15.3/4” Nominal Size
NMDC	9.1/2” Nominal Size (1 pc.)	9.1/2” Nominal Size (1 pc.)
MWD	9.1/2” Nominal Size	9.1/2” Nominal Size
NMDC	9.1/2” Nominal Size (1 pc.)	9.1/2” Nominal Size (1 pc.)
Stabilizer	22.1/2” Nominal Size	15.3/4” Nominal Size
Multi Circulation Sub	9.1/2” Nominal Size	9.1/2” Nominal Size
Float Sub	9.1/2” Nominal Size	9.1/2” Nominal Size
Shock Sub	9.1/2” Nominal Size	9.1/2” Nominal Size
Downhole Motor with bent sub	11.1/4” Nominal Size	9.5/8” Nominal Size
Bit	TCI Bit (23”)	TCI Bit (16”)

BHA configurations are given for the first two sections only since these sections are of particular interest within the comparison of the two different drilling techniques.

The most conservative and already proven approach for hard rock drilling in terms of drill bits is to utilize TCI bits with an IADC of 645 or 647 or higher. These bits should provide a good balance between durability and aggressiveness to optimize the ROP. (Erdwerk GmbH 2020d, 2020e) This is why TCI bits are considered within the reference BHA for the economic analysis. However, a realistic approach is to be experimental in terms of drill bits since the performance of different bit types may vary significantly. An overview of the bit strategy for the planned project may be found in Figure 52.

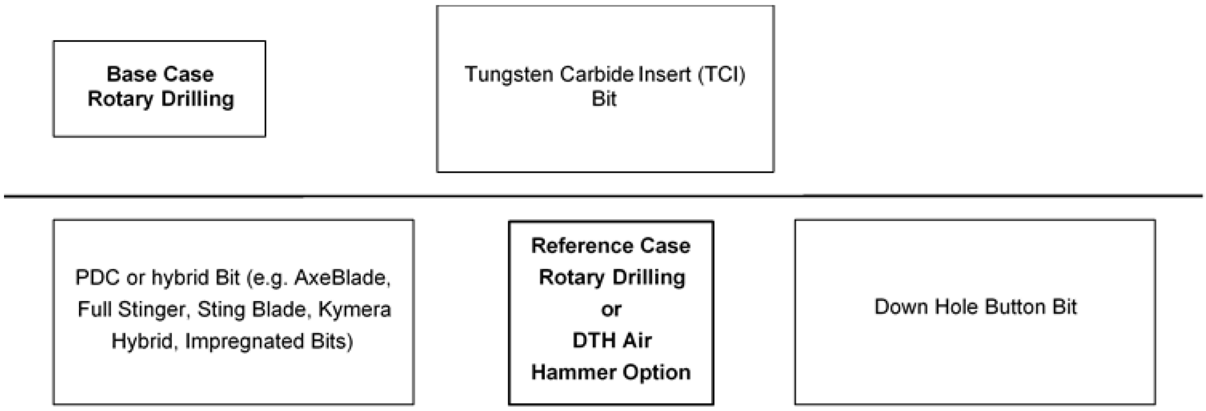

Figure 52: Drill bit options

In case the very promising hydraulic mechanical hammer (see chapter 2.7) is used. Either TCI bits or special PDC bits (Sting blade or Full stinger) may be used. (Erdwerk GmbH 2020b)

3.5 Tendering Approach for Air Hammer Drilling Equipment

This chapter deals with the tendering of, compared to conventional rotary drilling, additionally required services when conducting air hammer drilling. Each described service represents a separate lot within a tender process. It was decided to split the necessary services into the following lots to obtain the required equipment and services to conduct air hammer drilling.

- Air Package
- DTH Air Hammer and DTH Button Bits

These tender documents were attached to the tender package for the drilling contractor. It was intended that the respective drilling contractors, participating within the tender process, should provide these services through subcontractors.

The service for providing necessary technical equipment and chemicals for mist and foam drilling was incorporated into the lot Drilling Fluid since synergies with this service were identified. Additionally, required equipment such as the RCD and blooie line were introduced as optional positions to the service specification list of the drilling contractor. With this tender setup, all air hammer related services and equipment to perform air hammer drilling are covered. The tender documents are the intellectual property of Erdwerk GmbH and, therefore, not publishable within this thesis.

3.5.1 Air Package

This chapter details the requirements for a potential service company to provide services related to the air package for the air hammer drilling operation. These requirements form the basis of tender documents for the respective service.

Following equipment is to be provided by the service company:

- 8 x Compressors (rated min. 25 bar output pressure) capable of delivering 5,000 l/s of air when used in parallel.
- 2 x Backup Compressors (same specifications as the primary compressors).
- 3 x Boosters (rated min. 100 bar output pressure) capable of delivering 5,000 l/s of air when used in parallel. Input pressure should match the compressors output pressure.
- 1 x Backup Booster (same specifications as the primary boosters).
- Air Volume and Pressure Recorder.
- Air Manifold with appropriate in and outlets and connections to connect the compressors and to supply the fluid stream to the booster.
- Additional equipment required for the setup of a functional air package system (e.g., high-pressure lines, connections, valves and gauges).

Personnel service from the contractor is required for the setup and putting into operation of the whole air package, as well as regular maintenance and repair works. If possible and technically feasible, air package personnel should train the rig crew and leave the drilling site in case operations are running smoothly.

3.5.2 DTH Air Hammer and DTH Button Bits

This chapter details the requirements for a potential service company to provide services related to the air hammer and suitable down the hole button bits. These requirements form the basis of tender documents for the respective service.

Following equipment is to be provided by the service company:

- DTH Air Hammer suitable for drilling the planned 23” and 16” sections including backup.

The DTH Air Hammer should be provided including lubrication agents, all required additional BHA components (e.g., bit shank, non-rotating stabilizer) and provision of necessary adapter parts (e.g., for the threads at the backhead of the hammer) to use the system in combination with the outlined HWDP’s and DP´s necessary for the operation. Furthermore, recommended spare parts to allow for onsite maintenance (e.g., Backhead with Reg Pin, Check Valves and Check Valve Springs, Bit Retaining Rings, Choke Set, etc.) should be provided by the respective service company.

Table 17 shows the planned button bit program and requirements for a potential contractor. Following further considerations are important:

To avoid unnoticed wear of the bits and the associated possible reduction of the borehole diameter, the service company which provides the bits is to present a bit program that takes into account the decrease in size of the bits in one section.

- Minimum borehole diameter at the end of the first section 21.1/2”
- Minimum borehole diameter at the end of the second section 15”

Table 17: Planned DTH button bit program

Section	Type of Drill Bit	Amount	Details	Back-Up Bits
1 23“	Down Hole Button Bit	As recommended by bit supplier*	Applicable for DTH Air Hammer Drilling Incl. Side wear Buttons (Gauge Protection) Optional: Diamond Enhanced Gauge Protection	As recommended by bit supplier
2 16“	Down Hole Button Bit	As recommended by bit supplier	Applicable for DTH Air Hammer Drilling Incl. Side wear Buttons (Gauge Protection) Optional: Diamond Enhanced Gauge Protection	As recommended by bit supplier

* Refer to section 3.3.4 Table 15 for an example.

Personnel service from the contractor is required for the design of an appropriate BHA for use in combination with the air hammer system and to maintain it during the operation. Furthermore, personnel should be on-site to assist in finding the operational sweet spot of the air hammer (WOB, RPM, flowrate) and to perform on-site maintenance activities on the air hammer and button bits if required. If possible and technically feasible, air hammer personnel should train the rig crew and leave the drilling site in case operations are running smoothly.

3.5.3 Mist and Foam Drilling

This chapter details the requirements for a potential service company to provide services related to mist and foam drilling as well as additional chemicals. These requirements form the basis of tender documents for the respective service. The respective service may be delivered by a drilling fluid service company or the air hammer supplier.

Table 18 gives an overview of the planned drilling foam program and lists potentially required additives which should be delivered by the respective service company.

Table 18: Overview of the planned foam program

<table>
<tr><th>Section</th><th>Main Fluid</th><th>Secondary Fluid</th><th>Water injection rate [l/min]</th><th>Proposed additional Chemical additives</th></tr>
<tr><td>1
23”</td><td>Air</td><td>Water and foam additives</td><td>12-40</td><td rowspan="2">Chemical additives to allow a faster degradation of the used drilling foam in the surface degradation facilities
Foam extender/stiffener
Corrosion inhibitor</td></tr>
<tr><td>2
16”</td><td>Air</td><td>Water and foam additives</td><td>12-24</td></tr>
<tr><td colspan="5">Foam extender/stiffener = e.g., Synthetic Polymer or PAC R, PAC L or Xanthan</td></tr>
</table>

The following equipment is considered the minimum to be supplied for the operations:

- Mixing tanks with impeller
- Mist Pump
- Metering pump
- Foam Generator

Personnel service from the contractor is required for the setup, putting into operation and subsequent operation of the equipment related to foam drilling (Mist pump, foam generator, mixing tanks, metering pump) as well as regular maintenance and repair works. Regular adjustments to the drilling fluid properties to provide optimum hole cleaning and maintain and optimized ROP are within the scope of the service personnel. If possible and technically feasible, fluid service personnel should train the rig crew and leave the drilling site in case operations are running smoothly.

3.6 Probabilistic Drilling Time Estimation with Monte Carlo Simulation

The following chapter deal with the drilling time estimation utilizing the @Risk software package. Main objective is to develop a probabilistic time estimation comparing both, drilling using conventional rotary drilling with TCI bits, and the air hammer technology. The obtained data acts as an input to assess time-dependent costs within the economic analysis and receive time and cost probability distributions.

3.6.1 Model Setup and Data Gathering

The model setup follows the guidelines elaborated by (Lentsch 2013) during his work on probabilistic well construction estimation. Figure 53 illustrates a very global workflow that is followed to obtain the total well construction time using a Monte Carlo simulation.

The whole well construction process can be subdivided into sequential working steps. These working steps are called processes and consist of seven section-wise repeating procedures, which are: Drilling, Logging, Conditioning Trip, Running Casing or Running Liner, Cementing, WOC/BOP, and Drilling Cement/Shoe. The time estimation starts with spud and ends with completed drilling of the reservoir section. Therefore rig up, logging, testing and acidizing of the reservoir (IPS works), running of an optional slotted liner, and rig down are excluded from the time estimation. (Lentsch 2013)

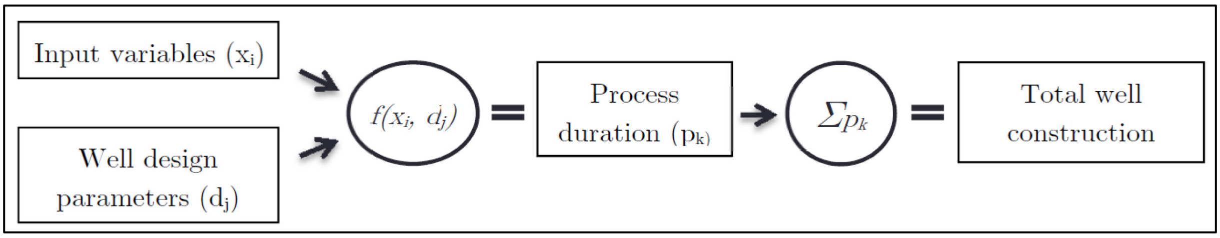

Figure 53: Conceptual schematic for modeling the well construction time[1]

Rig up and rig down of the drilling rig, including peripheral installations, are settled as a lump sum for this project and, therefore, not regarded as time-dependent cost. Time estimation related to the IPS works and completion of the reservoir section are treated separately, having no influence on the air hammer and rotary drilling cost comparison, which is why this is not within scope of this thesis.

Figure 55 shows needed input parameter for the Monte Carlo simulation in tabular form. The ROP is inserted in form of a distribution function best matching offset data for drilling under comparable circumstances (e.g., bit type, borehole size, drilling parameter) within same or comparable geological formations. For this thesis, ROP data from literature (Baujard et al. 2017) and recent bit reports attached to offers from various service providers were used. This data was thoroughly analyzed and provided the basis for a probabilistic ROP estimation for rotary drilling utilizing TCI bits within fractured gneiss. A graphical representation of the gathered ROP data can be found in Figure 54.

The drilling time in hours is calculated by using the following formula (Lentsch 2013) :

$$Drilling\ time = \frac{Section\ length\ [m]}{ROP\ [\frac{m}{h}]} + DFT\left[\frac{h}{100m}\right] * \frac{Section\ length\ [m]}{100} \qquad \text{(Eq. 7)}$$

[1] Lentsch 2013. *A Probabilistic Approach to Time and Cost Estimation for Geothermal Wells*. Leoben. Master Thesis, February 2013.

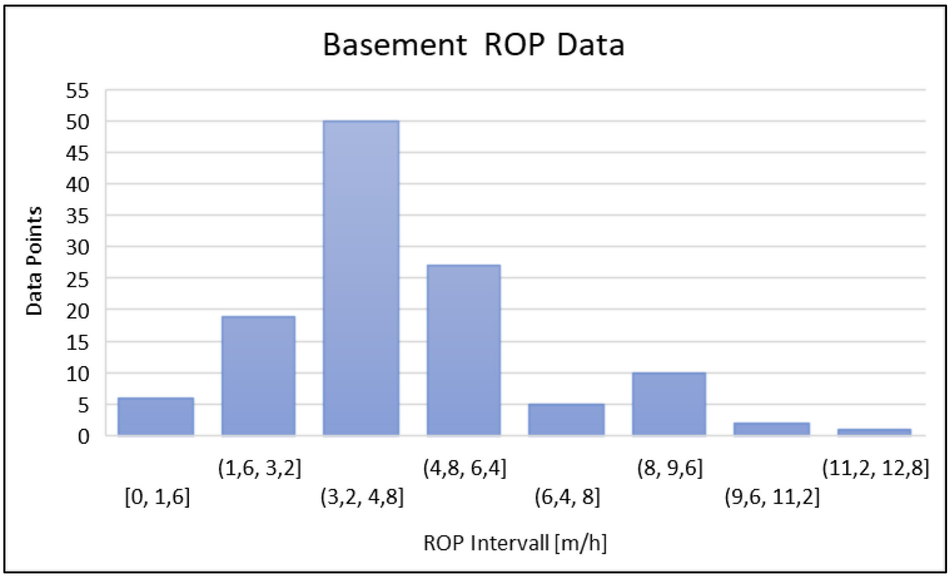

Figure 54: Basement ROP data set[1][2][3]

Input Data		
Section Depths		
Depth 1. Section	1000.00	[m MD]
Depth 2. Section	1800.00	[m MD]
Depth 3. Section	2640.00	[m MD]
Depth 4. Section	3310.00	[m MD]
KPI Net Drilling Progress (ROP)		
ROP 1. Section	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	[m/h]
ROP 2. Section	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	[m/h]
ROP 3. Section	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	[m/h]
ROP 4. Section	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	[m/h]
KPI Drilling Flat Time (DFT)		
DFT 1. Section	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	[h/100m]
DFT 2. Section	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	[h/100m]
DFT 3. Section	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	[h/100m]
DFT 4. Section	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	[h/100m]
Drilling Time (Pick up BHA until lay down BHA)		
Drilling Time 1. Section	Calculated from Section Depth, ROP and DFT	[days]
Drilling Time 2. Section	Calculated from Section Depth, ROP and DFT	[days]
Drilling Time 3. Section	Calculated from Section Depth, ROP and DFT	[days]
Drilling Time 4. Section	Calculated from Section Depth, ROP and DFT	[days]

Figure 55: Simulation input data and drilling time calculation after (Lentsch 2013)

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[1] Drillwerk 2020. *Drill Bit Proposal*, 2020.

[2] Baker Hughes 2020. *Drill Bit Proposal*, 2020.

[3] Baujard et al. 2017. *Rate of penetration of geothermal wells: a key challenge in hard rocks*.

The @Risk fit manager was used to find the best fitting distribution function for the respective dataset (Figure 54). Figure 56 shows an example of the distribution function fitting process for the ROP of the first section. To obtain the probability distribution function for the respective data set, lower and upper function limits need to be assigned. This is done in accordance with engineering knowledge concerning the considered variable. In case of ROP, the lower limit is set to 0.5 m/h and the upper limit to infinity. In this case, the @Risk Loglogistic function best matches the input data under consideration of the assigned boundary conditions. Ranking according to Akaike information criteria (AIC), Bayesian information criteria (BIC), and chi-squared statistics in combination with statistical parameters such as mode, mean, median, and standard deviation, support the decision process. The Loglogistic distribution function obtained for the respective ROP data set is assigned to the respective input field, where it will be used as input for the Monte Carlo simulation. This process is repeated for all four sections, respectively.

Generally, the same fitting process is carried out for DFT. However, the data set used is mainly based on data from projects within the sedimentary molasse basin (company database). Drilling flat time includes processes such as making connections, tripping in, and tripping out at the beginning, respectively end of a section, and unplanned drilling interruptions (e.g., loss of circulation, cutting accumulation, stuck pipe, etc.). Since frequent necessary bit changes are assumed for the basement drilling operation, which is not pictured within the company internal DFT data set, the way to include the additional DFT with a deterministic approach is used. Bit run length data from the ROP data set was statistically analyzed. The P50 case showed a bit run length of 150 m. Based on that data, a bit run length of 150 m was anticipated for all four sections. The flat time resulting from these additional trips can be calculated by accounting three hours for the bit change on surface and a tripping speed of 300 m/h within cased hole and 200 m/h within open hole. The assumptions are realistic for super single rigs with an automated pipe handling system. This approach leads to an additional DFT of approximately 4 h/100 m for the first section. The process of distribution curve fitting and additional deterministic DFT estimation is repeated for all four sections, respectively.

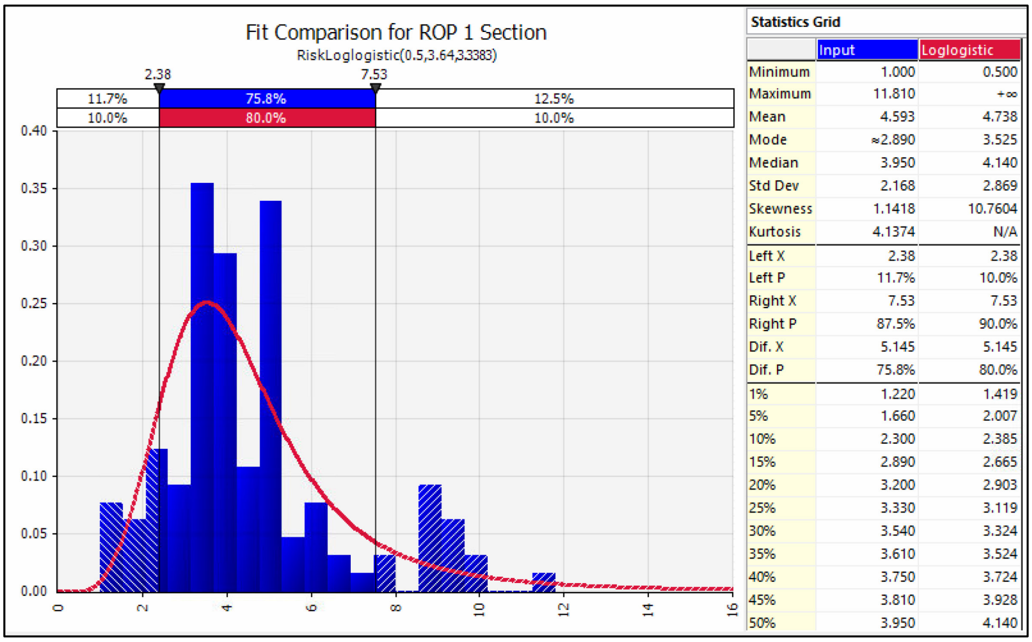

Figure 56: ROP data fitting process

Figure 57 gives a tabular overview of the considered processes necessary to estimate total well construction time. Data from offset wells is available for all processes. It is assumed that operations such as cementing, running liner (assumed that the borehole will be filled with water during POOH the drilling BHA), or installation of a BOP are comparable in duration for basement drilling operations and operations within sedimentary basins. Therefore, data from the internal company database was used to perform the distribution function fitting for these processes. The process marked in a different colour, representing intermediate IPS works, is not considered within this estimation. The processes are divided into works considered to be working hours for the rig, and those considered being waiting hours. This classification plays an essential role in the economic analysis discussed later within this thesis. As soon as all required input parameters are assigned accordingly, the simulation is run, and the results are interpreted.

To estimate well construction time using the air hammer technology ROP as well as DFT data for the first two sections, were adjusted. Air hammer manufacturer provided ROP estimations ranging from 6 m/h to 10 m/h for the first section and 8 m/h to 12 m/h for the second section. These estimations are best represented by a normal distribution, as shown in Figure 58. No data concerning the effect of air hammer utilization on connection time is available, which is why the DFT was not changed in that sense. The deterministic DFT approach changed slightly since the bit run length increased to 250 m for the first section and 200 m for the second section, respectively. Air hammer manufacturers assume a bit consumption of four to six per section. Setup of air package and peripheral equipment such as assembly and disassembly of all technical equipment necessary for creating a functional drilling foam system for the operation of an air hammer is included with respective lump sum positions and, therefore, not time-dependent.

	Process	Input	Classification
1. Section	Drilling	Drilling Time	Working Hour
	OH Logging	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Waiting Hour
	Conditioning Trip	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Working Hour
	Running Casing	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Working Hour
	Cementation	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Working Hour
	WOC/BOP/Pick up Pipe	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Waiting Hour
2. Section	Drilling Cement/Shoe, FIT	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Working Hour
	Drilling	Drilling Time	Working Hour
	OH Logging	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Waiting Hour
	Conditioning Trip	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Working Hour
	Running Liner	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Working Hour
	Cementation	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Working Hour
	Milling Run (PBR)	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Working Hour
	Running Tieback	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Working Hour
	WOC/BOP/Pick up Pipe	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Waiting Hour
3. Section	Drilling Cement/Shoe, FIT	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Working Hour
	Drilling	Drilling Time	Working Hour
	Intermediate Testing, Acidizing, OH Logging*	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Waiting Hour
	Conditioning Trip	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Working Hour
	Running Liner	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Working Hour
	Cementation	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Working Hour
	WOC/BOP/Pick up Pipe	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Waiting Hour
4. S.	Drilling Cement/Shoe, FIT	Distribution Function (e.g. Triangle, Normal, Weibull, etc.)	Working Hour
	Drilling	Drilling Time	Working Hour

Figure 57: Overview of considered processes per section with respective input and classification after (Lentsch 2013)

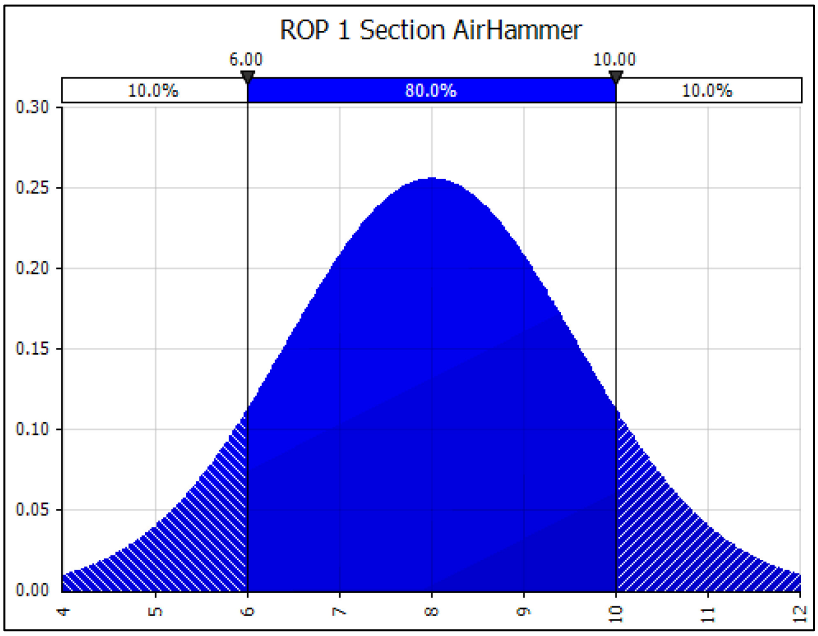

Figure 58: Air Hammer ROP distribution function for the first section

3.7 Setup of the Economic Analysis

This chapter intends to provide a well-established overview of the setup and methodologies used to perform the economic analysis, comparing project cost for the conventional and air hammer drilling approach. First, the economic master spreadsheet structure, highlighting the approaches for obtaining time-dependent and time-independent data required to obtain the overall cost per lot, will be discussed. Secondly, the data gathering process in terms of prices for the respective applicable service provision, which forms an integral part of this thesis, will be highlighted in a separate chapter. Eventually, the methodology of the economic analysis will be thoroughly discussed.

In total, 18 different lots form the basis for the conventional approach of the planned geothermal project. The numbering of the different lots will be kept throughout the thesis and should not lead to confusion. The lots are named and numbered as follows:

01 – Drilling Contractor
01.1 – Gas Protection Service
02 – Running Casing and Centralizer
03 – Non-Rotating Protectors
04 – Thread Cleaning
05 – Directional Drilling
06 – Drilling Fluid
07 - Cementing
08 – Liner Hanger and Float Equipment
09 - Casing
10 - Wellheads
11 – Drill Bits
16 – Mud Logging
17 – Waste and Fluid Management
18 – Wireline Logging
19 – Short Term Testing
19.1 Acidification
20 – Long Term Testing

Thereof, five relevant lots were identified for a cost analysis comparing air hammer drilling and the conventional approach. The costs for those lots are highly influenced by the change between the two drilling approaches, mainly governed by the change of time-dependent and time-independent quantities. These lots are as follows:

01 – Drilling Contractor
05 – Directional Drilling
06 – Drilling Fluid
11 – Drill Bits
16 – Mud Logging

The other lots are not influenced or negligible affected by the change between the two drilling approaches. For example, lot 02 – Running Casing and Centralizer remains unchanged in terms of time-dependent quantities. The rig up and rig down time of the casing running equipment and the time needed for the casing installation remain independent of the chosen drilling approach. The well design will not be changed depending on the selected drilling approach either, meaning that the time-independent quantities (e.g., amount of casing to be installed, required centralizer, etc.) remain independent of the selected drilling approach as well.

For the air hammer drilling approach, two additional lots were introduced:

01.2 - Air Package
01.3 - DTH Air Hammer

The setup of those lots is described in section 3.5. Expert interviews and bidder interviews revealed additional required services and equipment not covered within the service specification list of the tender documents to perform air hammer drilling. These additional necessary services and equipment are included in lot xx – Drilling Foam Additives and Equipment and lot xx – Energy. A detailed explanation of all-important lots and the approach for determining respective applicable quantities and prices will be detailed throughout the following chapters.

3.7.1 Setup of the Economic Analysis Spreadsheet

The economic analysis spreadsheet is an excel tool that allows performing different economic analysis for a particular project. The main application is to assess total project cost with varying probabilities of occurrence (P10, P50, P70) to assist the operator with authorization for expenditure (AFE) decisions. Furthermore, the spreadsheet allows a fair comparison of bidders for individual lots specified within the project. The spreadsheet is designed to allow for visualization of costs per well section and lot.

The spreadsheet consists of different tabs. The overview tab summarizes cost per lot for designated probability cases. Other tabs contain time estimation data exported in a suitable format from the probabilistic time estimation conducted with @Risk (see section 3.6 for the probabilistic time estimation), or time-independent data. All other tabs are constructed as schematically shown in Table 19. These tabs are built for all 18 relevant lots. The service specification and quotation prices list specified for every lot within the tender documents contains all applicable service specifications required to perform the tasks outlined for every lot. This is an individual list for every required lot during the drilling process of the project. There are two possible applicable types of quantities. Time-independent quantities are, for example, lump sums (e.g., mobilization and demobilization of equipment, assembly and disassembly of the drilling rig, etc.), pieces (e.g., centralizer, float equipment, etc.), volumes (e.g., drilling fluid, cement, etc.), and others (e.g., meters of casing, wireline measurement depth charge per meter, etc.). These time-independent quantities can be obtained from the drilling program and well design as well as from experience. The probability (P10, P50, P70) comes into the economic analysis via the time-dependent quantities and the probabilistic time estimation conducted for the project. Time-dependent quantities may be the rig's operating or standby daily rate, rental rates for equipment, or personnel remuneration per shift. Every lot consists of a mixture of time-independent and time-dependent service specification tasks. Possible contractors are offering prices for every position contained within the service specification list. The offered prices are multiplied with the respective applicable quantity (time-dependent or time-independent) for every probability of occurrence (P10, P50, P70). The outcome is the cost per described task for every probability case. The sum of the cost for all tasks contained within the P10 case yields the overall P10 cost for this lot. The sum of P10 cost for all lots yields the P10 project cost. The quantities for every probability case are assigned to a particular section within the well construction process. Table 20 shows a more detailed schematic of the quantities section within the spreadsheet. For this project, every probability case is divided into seven sections. Section one, towards section four, illustrates the drilling process from the start of drilling works in the first section towards the end of drilling works within the reservoir section. Short term tests include all works related to the short term testing (incl. acidification works) of the well and optional installation of a slotted liner within the reservoir section. Typical tasks assigned to the section drill site are, for example, works conducted before the start of drilling the first section (e.g., assembly of the drilling rig). The section long term tests should display quantities and subsequently cost related to long term testing of the well.

Table 19: Schematic setup of the master spreadsheet

Service Specification List	Unit	Price Bidder x	Quantities			Cost		
Task 1	Time-Independent (e.g., Lump Sum, piece, etc.)	x	P10	P50	P70	x*P10	x*P50	x*P70
Task 2	Time-dependent (e.g., day, hour, etc.)	y	P10	P50	P70	y*P10	y*P50	y*P70

Table 20: Schematic representation of the quantity setup per section

Quantities						
P10						
Drill Site	**1. Section**	**2. Section**	**3. Section**	**4. Section**	**Short Term Tests**	**Long Term Tests**
P10	P10	P10	P10	P10	P10	P10

In the end, the tool allows displaying cost per well construction section for specific tasks and lots considering different probabilities. This makes the spreadsheet a powerful tool to create an economic analysis for different drilling approaches based on service providers' recent offers. Prices for all tasks described within every lot and the respective applicable quantities for the conventional and air hammer approach allow estimating potential cost savings if selecting one method over the other. A detailed explanation of the economic analysis approach is given in section 3.7.3.

3.7.2 Price Survey

A private tendering process started in November 2019 to obtain bids for the required services of the planned geothermal project. Bidder interviews and reception and evaluation of the final offers were conducted during summer and early fall 2020. Prices from the most competitive bidder in terms of overall cost and technical quality are used as a basis for the economic analysis.

3.7.3 Economic Analysis

To simplify the process, the economic analysis is based on cost elaborated from relevant lots and air hammer lots only. First, the overall costs of relevant lots for the conventional drilling approach are estimated. Relevant lots are lots that have been identified as influenced by the change from conventional to air hammer drilling (as already explained in section 3.7). In a second step, the costs for these relevant lots considering the air hammer approach are estimated and the cost of air hammer lots are added to obtain the air hammer drilling cost. In the end, estimated cost for the air hammer approach are subtracted from the estimated cost with the conventional approach to obtain potential cost savings in case of air hammer drilling (see Figure 59 for a schematic representation). If the obtained cost difference is positive, the air hammer approach is estimated to bring an economic benefit to the project.

The potential cost savings in case of air hammer drilling are mainly driven by reducing overall drilling time per section caused by a potentially higher ROP estimated for air hammer drilling.

Figure 59: Schematic process of the economic analysis to obtain the overall cost difference

The main differences and adjustments to the quantities and service specification tasks for the relevant lots will be discussed within the following sections. A detailed description of the applied changes in case of air hammer drilling compared to conventional drilling is given for every affected lot within the following pages.

General remark: The currency exchange factor from Euro to US Dollar was selected to be 1.1. This gives conservative offered prices in Euro in case bidders have offered their equipment in US Dollar.

Lot – 01 Drilling Contractor

The main cost driver for this lot are time-dependent costs. The difference between this lot's cost for the conventional and air hammer approach is mainly driven by the faster section drilling times estimated for the air hammer approach. The following further changes were considered:

- Amount of 6.5/8” HWDP´s significantly reduced for the air hammer approach (12 to 6 pieces). This can be justified by the lower required WOB in case of air hammer drilling.
- The provision and assembly of a rotating control device (RCD) for the first and second sections are additional costs considered for air hammer drilling.
- Energy costs (electricity) are not included within the cost for lot 01 – Drilling Contractor, but considered within lot xx - Energy

Lot 05 – Directional Drilling

Since special BHA equipment will be provided by the drilling rig contractor and BHA assembly is covered by the combined effort of the air hammer personnel, rig contractors personnel, and engineers from the operator, the cost for the first two sections of this lot can be spared in case of air hammer drilling.

Lot 06 – Drilling Fluid

Prices provided by subcontractors of drilling fluid companies helped to determine the foam drilling cost in terms of equipment and chemical additives (e.g., foaming agent, defoaming agent, mist pump, mixing unit, etc.). The foam drilling service costs are displayed in the lot xx – Drilling Foam Additives and Equipment. Costs of lot 06 – Drilling Fluid for the air hammer service include the following:

- Vertical cutting drying system for further cutting drying at a different location and reduction of waste disposal cost.
- One solid control engineer per shift (incl. mobilization and demobilization of the personnel) to manage the solid control equipment (shaker and cutting drying system).
- All other quantities and therefore cost were not considered for the first two sections.
- Half of the chemical additive consumption to establish the desired rheological properties of the planned water polymer mud was considered for the 3rd and 4th sections of the well. This is a very conservative approach since the high volume first and second sections are drilled with air or foam.

Lot 11 – Drill Bits

The estimated cost for the first two sections of this lot can be spared for the air hammer drilling approach. A milled tooth bit (utility bit) was considered for drilling the shoe track at the beginning of section two.

Lot 16 – Mud Logging

Exact prices for the service provided with this lot were not available upon completion of this thesis. Therefore, a simple but comprehensive approach was used to estimate the cost for the air hammer and conventional approach of this lot. The main cost driver for this lot are time-dependent positions within the service specification list. This means that cost can be directly linked to the time this service needs to be on the drilling site. Comparison between the time estimation conducted for the conventional approach and the air hammer approach yielded that the time required for the completion of the project with an air hammer is 81.3 %, 79.95 %, and 78.99 % for the P10, P50, and P70 case, respectively of the time needed with a conventional approach (see section 4.1 for the time estimation results). Therefore, for the P10 case, the conventional P10 cost estimation for this lot was multiplied by 0.813 to obtain the respective air hammer-related cost.

Lot 01.2 – Air Package

The offered prices for the air package include 12 x Atlas Copco Y35 Stage IV Compressor and 3 x Atlas Copco B18TT-6233000 Booster. All surface piping to interconnect the compressor and booster units with each other and provide a connection to the air manifold and rig standpipe are included within the specified prices. The personnel structure consists of two people (one per shift) from the air package service company two assist with set up and operation of the equipment for the P10 case. For the P50 case, one supervisor and one junior operator are assumed for the day shift and one junior operator for the night shift. The very conservative P70 case includes one supervisor and two junior operators for the day shift and two junior operators at night shift. It is assumed that the disassembly and demobilization of the air package equipment happen during the completion of the second section (running liner and cementation works).

Lot 01.3 – DTH Air Hammer

This lot contains all relevant equipment and personnel connected to the air hammer and down the hole button bits. The P10 quantities include one hammer per section while the P50 and P70 are considering two hammers per section. Concerning the applied quantities for the DTH button bits, three per section, four per section, and five per section are applied for the P10, P50, and P70 cases, respectively. The operational structure concerning the air hammer supervising personnel is including one person per dayshift within the P10 and P50 case and two people (one per shift) for the P70 case.

Lot xx – Drilling Foam Additives and Equipment

As already discussed within previous chapters, certain additives are required for foam drilling. The essential additives needed for the operation of air hammer drilling, assisted by the liquid unloading abilities of foam, are air hammer oil, foaming agents, defoaming agents, viscosifying polymers like xanthan gum, and corrosion inhibitors. The costs for the mentioned additives are considered within the economic analysis.

To obtain the applicable quantities, it was necessary to estimate the pure air hammer drilling times. This data can be retrieved from the conducted time estimation. Please refer to Figure 62 for the conventional process time estimation and Figure 65 for the air hammer process time estimation. The second section's drilling times are obtained by adding the time for the process Drilling Cement / Shoe, FIT to the process Drilling. Further necessary data is the air consumption per section. The required air flowrate for adequate hole cleaning per section was discussed in section 3.3.2 and is assumed to be 300 m³/min for the first and 180 m³/min for the second section, respectively. The recommended water injection rate for mist and foam drilling can be obtained from Table 3. To get the values for an 16” hammer most likely to be used within the first section, a linear extrapolation of the values given within Table 3 was conducted. The lowest value given within the range of values from Table 3 is assumed to be the P10 value, while the P70 value is assumed to be the highest value. The P50 is the mean value calculate from the stated range of values. Table 21 summarizes the obtained data.

Table 21: Basic data for estimation of foam drilling additive consumption

		Drilling Time [days]	Air Consumption [m³/min]	Water Consumption [l/min]
1. Section	P10	10	300	16
	P50	12		24.5
	P70	14		33
2. Section	P10	10	180	12
	P50	12		18
	P70	15		24

An air hammer needs a certain amount of lubricating oil added to the air stream to allow adequate function of the internal mechanical components. Two different approaches to estimate total lubricating oil consumption for the planned project have been considered. Both methods are presented in section 2.5.1 under the headline Lubricating Oil Consumption. For the approach proposed by Mincon, an 18” hammer was assumed for the first section and a 12” hammer for the second section. The required amount of lubricating oil can be obtained from Figure 36. The respective obtained value needs to be multiplied by two since 100% of lubricating oil consumption increase is predicted by Mincon in case more than 7.6 l/min of water is injected into the air stream. The second approach is presented by Epiroc and assumes that 1 ml of lubricating oil should be added per m³ of air. A summary of estimated lubricating oil consumption per section is displayed in Table 22. The values obtained by the more conservative approach presented by Mincon are used within the economic analysis.

The recommended foaming agent dosage is shown in Table 4 and can be estimated to be 5 to 10 l per m³ of freshwater. The amount of fresh water per section can be obtained from the data displayed in Table 21. The estimated required amount of foaming agent is stated in Table 22.

Table 22: Lubricating oil and foaming agent consumption

		Lubricating Oil Consumption [l] Mincon	Lubricating Oil Consumption [l] Epiroc	Foaming Agent Consumption [l]
1. Section	P10	4824	4342	1158
	P50	5707	5136	3146
	P70	6754	6078	6686
2. Section	P10	2378	2569	856
	P50	2878	3108	2331
	P70	3492	3771	5028

A very rough assumption for the defoaming agent's dosage is to assume a defoamer concentration of 2 l per m³ of foamed water (see section 2.3.1.3 under headline Returned Foam Handling). To account for formation water influx and therefore higher returned foamed water volumes 50% of the injected water was added for the P50 and 100% for the P70 case. This means that for the P50 case of the first section a foamed water return of 36.75 l/min (24.5 l/min times 1.5) is assumed for the estimation. The injected water quantities can be obtained from Table 21.

A conservative approach for the polymer (Xanthan) dosage estimation assumes 1.4 kg per m³ of fresh water, as described within section 2.3.1.3.

The recommended amount of corrosion inhibitor was described in section 2.3.1.3 and can be estimated with 0.6 l per m³ of freshwater.

Table 23: Defoaming agent, polymer and corrosion inhibitor consumption

		Defoaming Agent Consumption [l]	Polymer Consumption [kg]	Corrosion Inhibitor Consumption [l]
1. Section	P10	232	330	139
	P50	629	599	252
	P70	1337	954	401
2. Section	P10	171	244	103
	P50	466	443	186
	P70	1006	718	302

The lot xx – Drilling Foam Additives and Equipment furthermore contains essential surface and subsurface equipment necessary to establish a functional air hammer drilling system. The surface system includes the cost for a mist pump, a static mixer for mixing the foam and cutting mixture with the defoamer (included within the package no separate price specified), and an air drilling cyclone. The subsurface BHA components include stabilizers, shock tools, and float subs.

Lot xx – Energy

Air Package Diesel Consumption

The energy cost in terms of diesel should not be neglected for air hammer drilling with diesel operated compressor and booster units. Therefore, the diesel cost will be taken into consideration for this economic analysis. As discussed in section 3.3.2 the Atlas Copco Y35 Stage IV Compressor and the Atlas Copco B18TT-6233000 Booster would be well suited for the planned project. Therefore, the technical specifications, including those units' fuel consumption, will be considered for the cost estimation. The respective datasheets for the compressor and booster units can be found in Appendix F. The diesel consumption for the compressor and booster units when operated under full load is stated within the respective datasheets. The diesel consumption per day was calculated for the compressors and boosters. This value is multiplied with the respective drilling time estimation obtained from the probabilistic time estimation with @Risk (P10, P50, P70). However, the full air package won't be operated under full load throughout the drilling operation. This is why only for the conservative approach of the P70 case, it is assumed that eight compressors and three boosters are running under full load throughout the estimated P70 drilling time. For the P10 case, four compressors and two boosters, and for the P50 case, six compressors and two boosters were assumed running under full load. The total diesel consumption for the air package considering the P10, P50 and P70 assumptions is displayed in Table 24.

Table 24: Air package diesel consumption

		Compressor Diesel Consumption [l]	Booster Diesel Consumption [l]
1. Section	P10	91,174	34,974
	P50	161,799	82,754
	P70	255,286	146,891
2. Section	P10	89,904	34,487
	P50	163,160	83,450
	P70	263,995	151,902

A diesel price of 1.5 € per litre including VAT was assumed for the project location. (Statista 2020a)

Drilling Rig Electricity Consumption

A project requirement is that only electrical driven rigs are allowed. This results in comparing diesel cost of the air package with electricity cost for operating the drilling rig.

To respect a conservative approach the energy requirements of the main rig components (top drive, mud pumps, shaker, mixer, desander and desilter, utility drives, etc.) when operated under full load during drilling were investigated. The total power consumption of the drilling rig and peripheral equipment is stated to be 4,637 kW. By considering the simultaneity factor recommended by the operating company, the drilling mode power consumption reduces to 3,090.1 kW. The drilling mode power consumption will be the basis for all further calculations related to the electricity consumption of the rig. An overview of important power requirements can be obtained from Table 25.

Table 25: Power requirements overview

	Total Power [kW]	Drilling Mode [kW]
Mud Pumps	2,898	2,031.9
Total Rig	4,637	3,090.1

To compare power requirements considering both drilling approaches the total estimated project duration (refer to section 4.1) for each approach is recalculated into operational hours and multiplied with the drilling mode power consumption of the rig. Doing this yields the estimated P10, P50 and P70 power requirements of the rig for both approaches assuming it is operated in drilling mode. The mud pumps have the highest energy requirements of all rig components. The mud pumps are usually considered to be on standby during air hammer drilling. To respect this, the electricity consumption of the mud pumps if operated in drilling mode is subtracted from the total air hammer drilling electricity consumption. The air hammer drilling time for the first two sections is converted to drilling hours and multiplied with the mud pumps power requirements in drilling mode. Doing this yields the estimated P10, P50 and P70 power requirements of the mud pumps for the drilling time during the air hammer approach. The obtained value is subtracted from the former total air hammer drilling power consumption including the mud pumps in operation. The result delivers air hammer drilling power consumption with mud pumps on standby. Table 26 shows an overview of the most important calculated values.

Table 26: Electricity consumption overview

Electricity Consumption (Drilling Mode)		
	Conventional [kWh]	Air Hammer [kWh]
P10	6,146,580	4,021,751
P50	7,541,574	4,863,905
P70	8,221,644	5,094,829

A industry electricity price of 0.14 € per kWh including VAT was assumed for the project location. (Statista 2020b)

4 Results and Discussion

This section discusses the results obtained from the time estimation and economic analysis. It covers and discusses the simulated well construction time for both rotary and air hammer drilling. Furthermore, it presents the outcome of the economic analysis for the air hammer and conventional approach and points out most significant differences. Cost per section is discussed in detail with representative graphs and charts. Lastly, a direct cost comparison for both approaches will be reviewed.

4.1 Probabilistic Time Estimation

The probabilistic time estimation utilizes the Monte Carlo simulation to produce well construction times based on input data sets. Input data and model setup are discussed within the methodology chapter of this thesis.

The produced output consists of simulated time estimations for a particular process. The cumulated process time estimations yield the total well construction time. Each time estimation is marked with a certain probability of occurrence. The P90 means that based on the selected input data, 90% of the simulation results delivered a time estimation value exactly at or lower than the P90 value. P50 is defined that 50% of the simulated values exceed the P50 value, and 50% are lower than the P50 value. The P50 case has a higher chance of occurrence than the P10 or the P90 case. In other words, the P90 represents a somewhat conservative value, while the P10 is very ambitious and might most likely be exceeded.

Produced figures are time estimation values for every defined process differentiating working and waiting hours. Generated graphs are a time versus depth diagram visualizing the different well construction time estimations versus depth (P10, P50, P90). Produced figures can be utilized to produce other meaningful output such as total standby and total working time per section, or drilling time per section (excluding works such as running casing or liner amongst others).

4.1.1 Conventional Approach

A probability distribution for the simulation result of total well construction time representing the conventional approach can be found in Figure 60. The distribution has an expected mean value of 104 days. Mode (98 days) and median (101 days) are located left of the mean because of the long tail to the right-hand side of the distribution (skewness = 1.14). The P10 value is 82.9 days, and the P90 value is 127.5 days. The distribution has a kurtosis of 6.4. The standard deviation is 19 days.

Engineering knowledge and statistical data indicate that the simulation output is within a reasonable shape and range.

Figure 61 shows a time versus depth diagram with the simulated well construction times. The only process contributing to depth is drilling. All other processes are carried out, while hole depth remains unchanged. A detailed summary of all considered processes and respective simulated process durations for the P10, P50, and P90 percentile can be found in Figure 62. It can be obtained that the drilling operation of the third section (22 days, P50) is considerably longer than for the first (18 days, P50) and second section (17 days, P50), although section lengths of the second and third section are almost equal (approx. 800 m MD) and the section length of the first section being the longest (1,000 m MD). The two input parameters defining the simulation output are ROP and DFT. The ROP input distribution function is the same for all four sections, which leaves the DFT responsible for this behaviour. Two things must be considered: First, problems were often encountered during drilling of the third section, which is why high DFT values are present within the input data set. The minimum extreme value distribution (RiskExtvalueMin) best fitted the DFT data representative for the third section. In contrast, DFT data of the second section could be best fitted with a RiskGamma distribution. 24 h/100 m (Mean), 28 h/100 m (Mode), and 25 h/100 m (Median) with a standard deviation of 9.3 h/100 m are representative for the third sections DFT data. With 15 h/ 100 m (Mean), 12 h/100 m (Mode), and 14 h/100 m (Median) with a standard deviation of 6.0 h/100 m, DFT data representative for the second section shows a strong tendency to be lower compared to the third sections data. Second, frequent anticipated bit changes require tripping. The time consumed by tripping out of the hole and back in again is directly proportional to wellbore depth. This fact increases DFT with increasing wellbore depth.

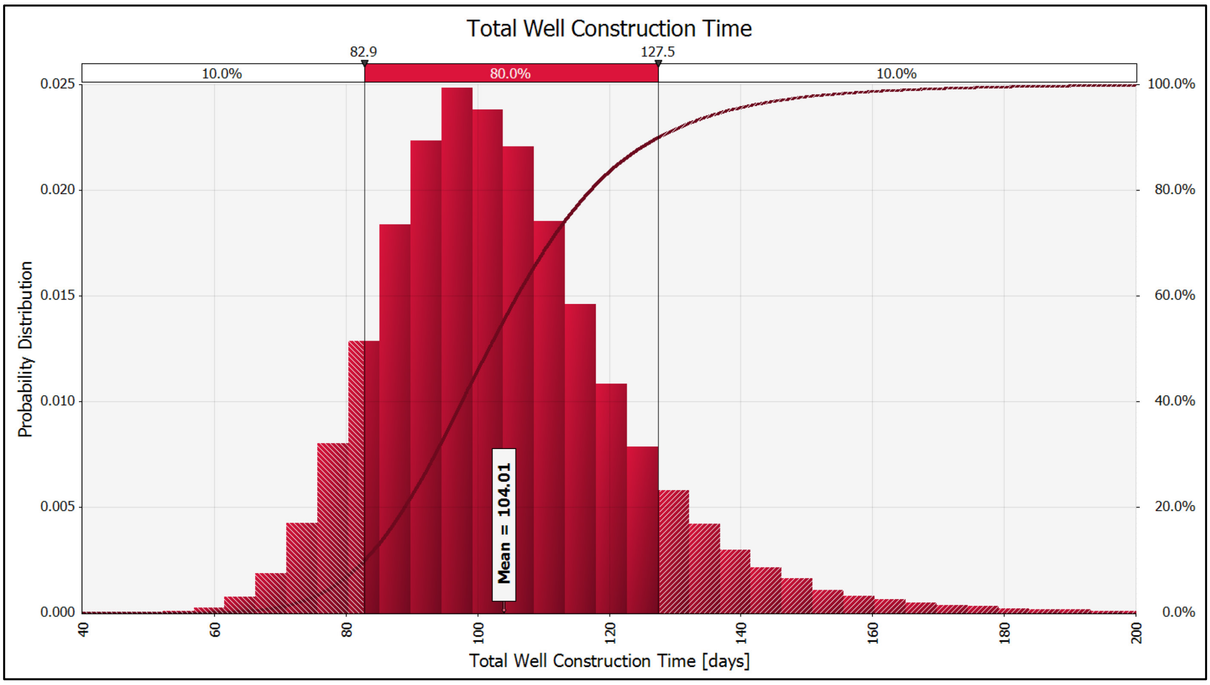

Figure 60: Probability distribution and cumulative probability of the total well construction time (conventional)

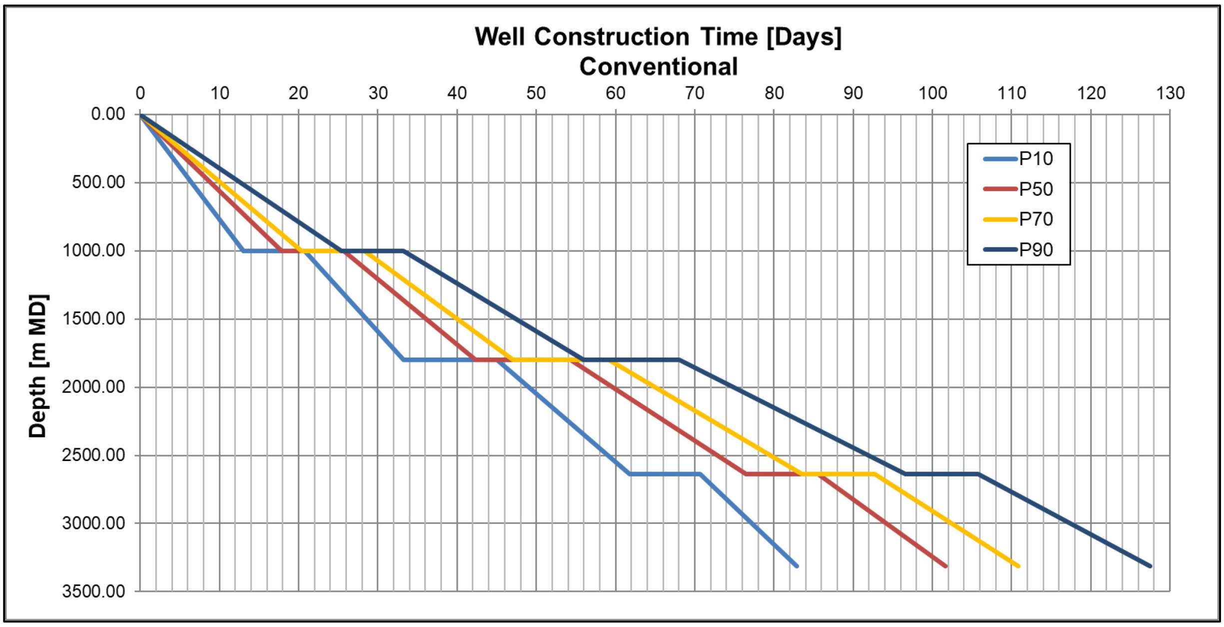

Figure 61: Time vs. Depth Diagram (conventional)

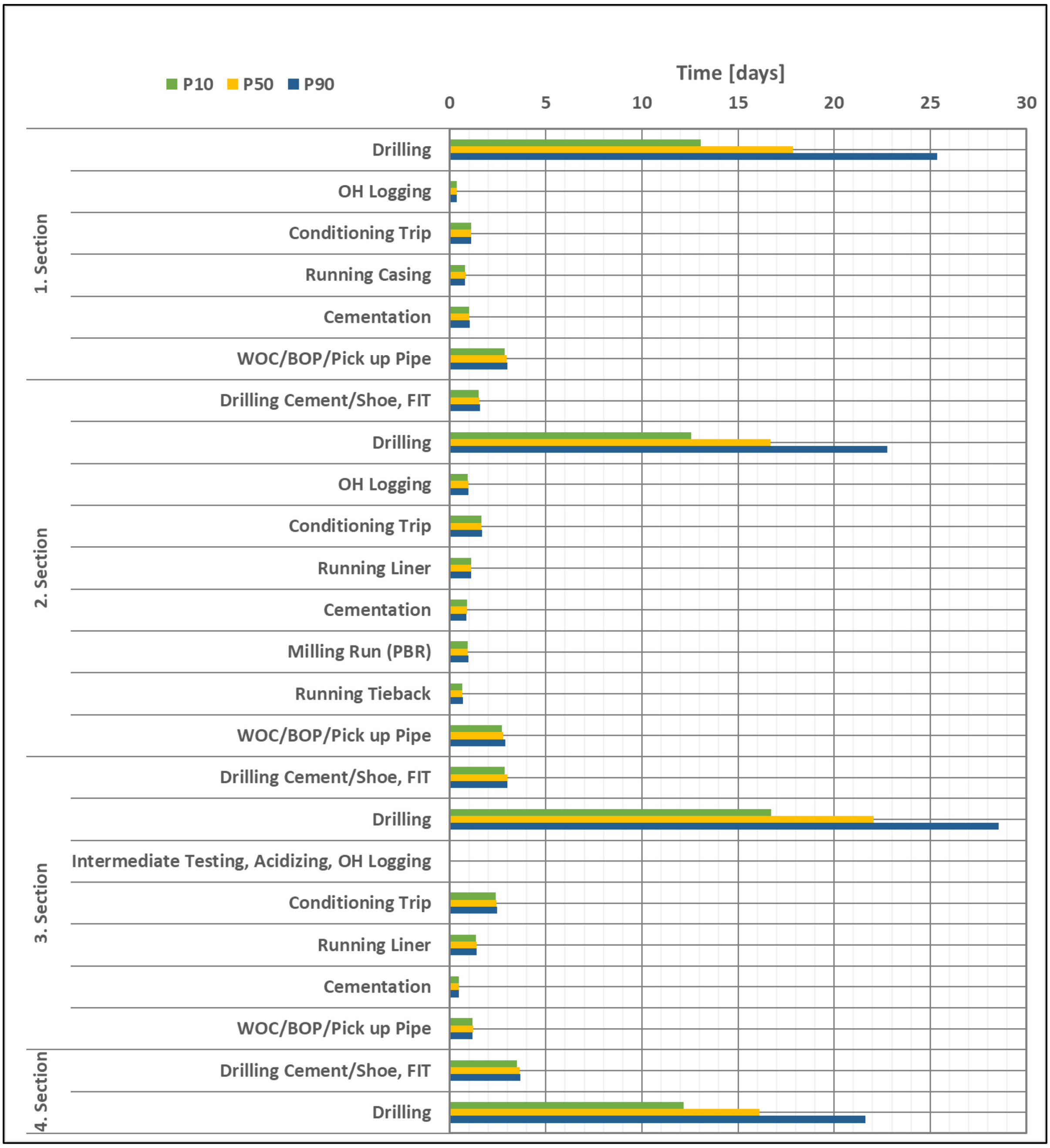

Figure 62: Process time estimation overview (conventional)

4.1.2 Air Hammer Approach

A probability distribution for the simulation result of total well construction time for the air hammer approach can be found in Figure 63. The distribution has an expected mean value of 91 days. Mode (88 days) and median (90 days) are closer together as encountered during investigation of the conventional simulation results. The distribution has very little skewness of 0.68. The P10 value is 75.4 days, and the P90 value is 106.6 days. The peak of the distribution is slightly gentler (kurtosis = 4.7) compared to the result of the conventional simulation (kurtosis = 6.4). The standard deviation is 13 days, which is lower compared to the conventional simulation result (19 days). The slightly gentler peak and lower kurtosis are related to the normal distribution function of the air hammer ROP within the first and second section. A more detailed explanation can be found within the sensitivity analysis (see chapter 4.1.4).

Engineering knowledge and statistical data indicate that the simulation output is within a reasonable shape and range.

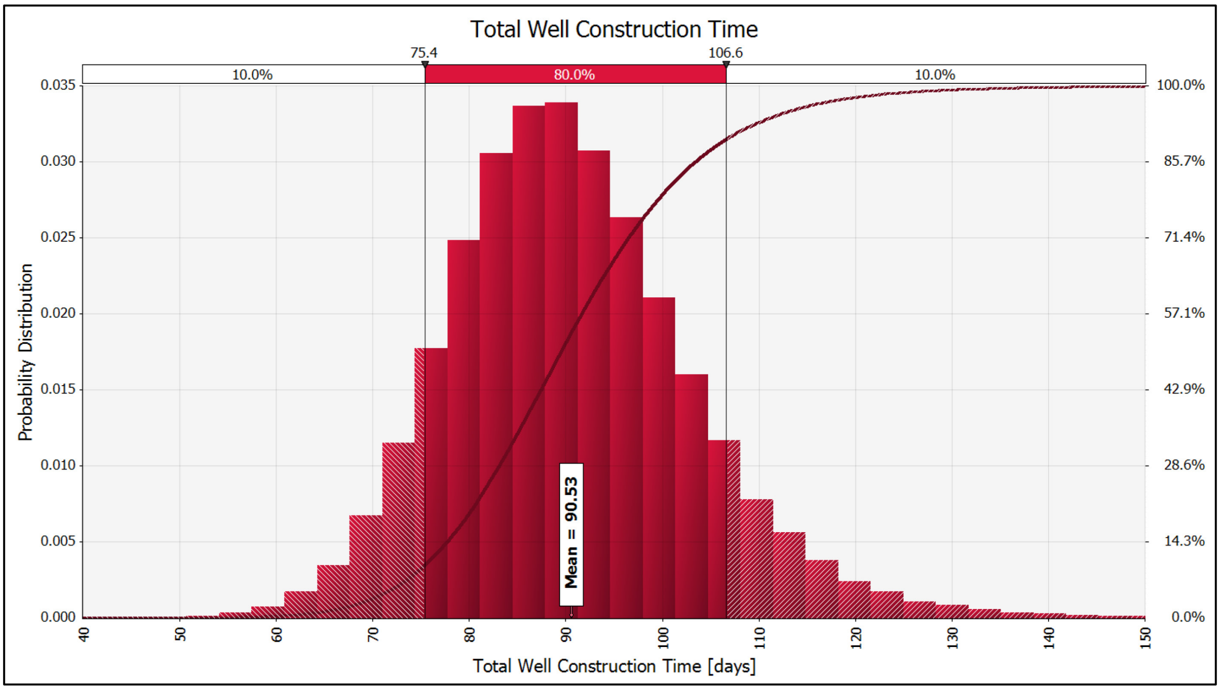

Figure 63: Probability distribution and cumulative probability of the total well construction time (air hammer)

Figure 64 shows the time versus depth diagram containing the simulated well construction times. The only process contributing to depth is drilling. All other processes are carried out, while hole depth remains unchanged. A detailed summary of all considered processes and respective simulated process durations for the P10, P50, and P90 percentile can be found in Figure 65.

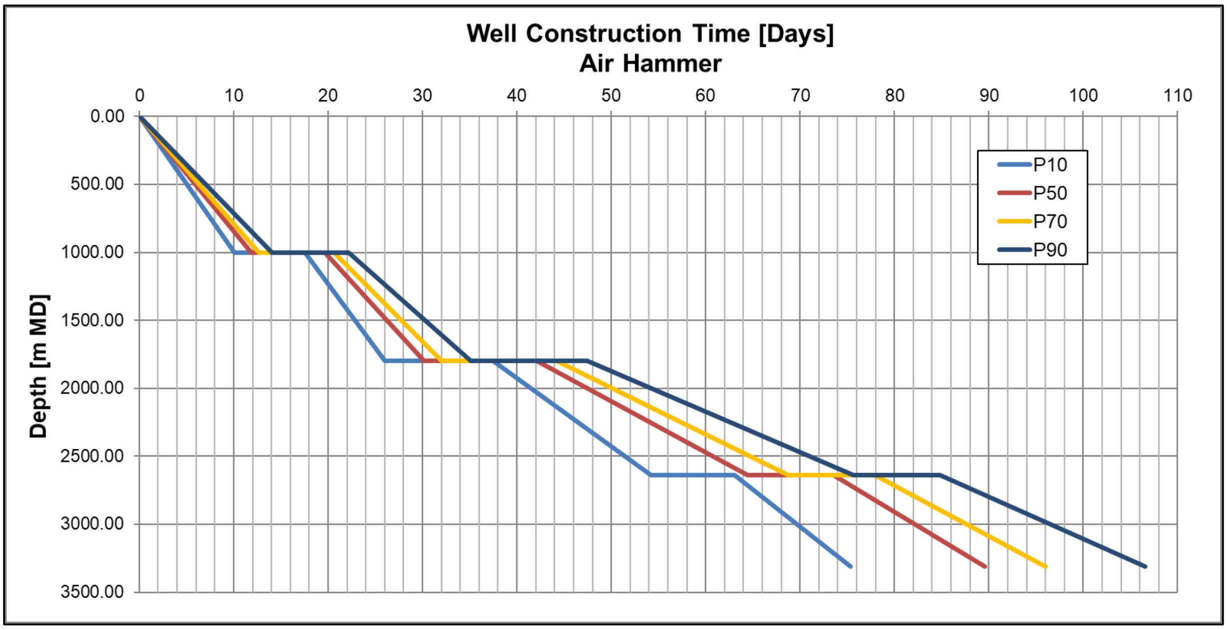

Figure 64: Time vs. Depth Diagram (air hammer)

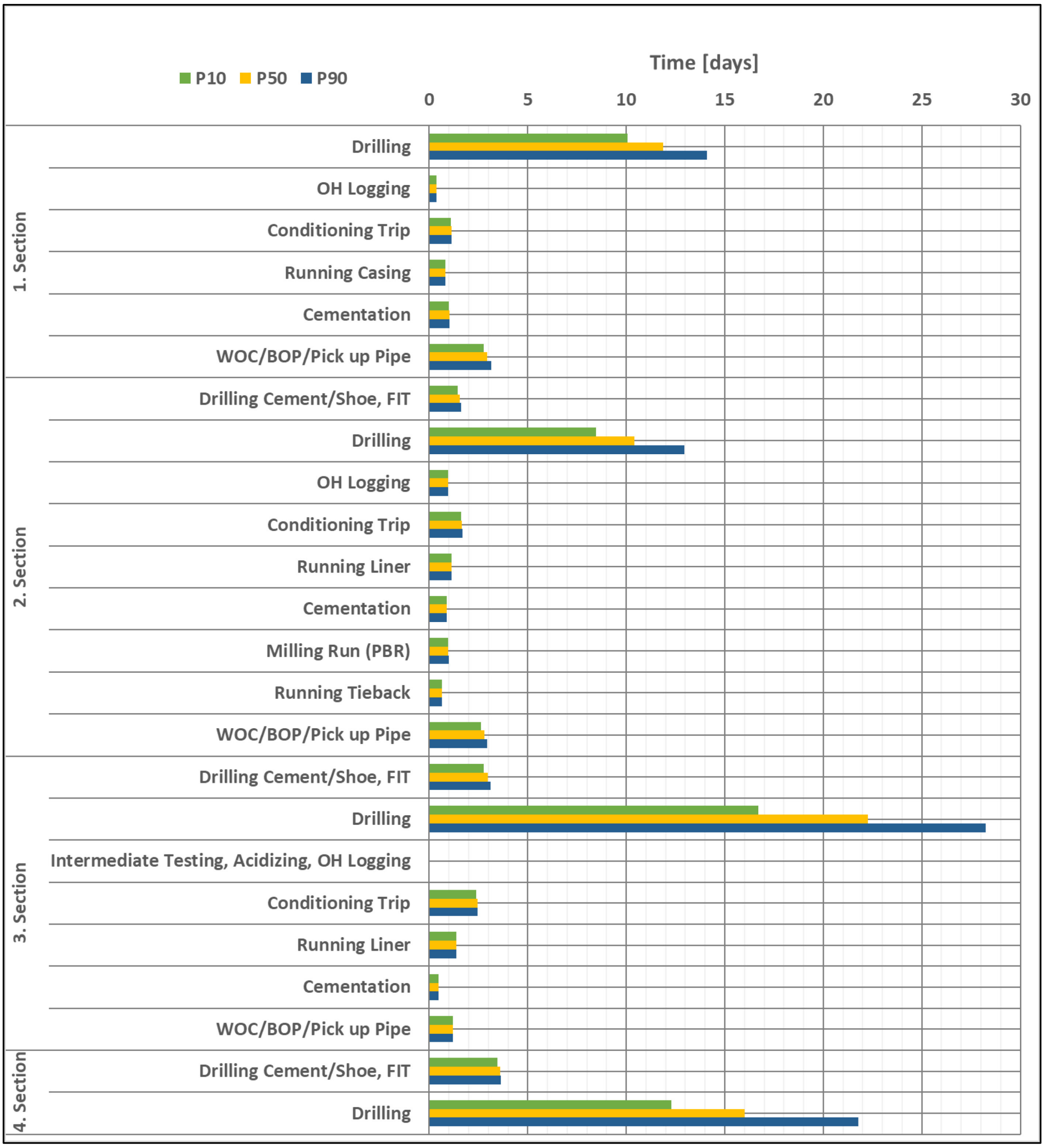

Figure 65: Process time estimation overview (air hammer)

4.1.3 Direct Comparison

A direct comparison between the simulated P50 well construction time for the air hammer and conventional case can be found in Figure 66. The simulation predicts time savings of approximately 12 days for the total well construction time. This time is saved due to a potentially higher ROP while drilling the first and second section. Input for all non-drilling processes is unchanged between the conventional and air hammer case. Therefore, all processes, excluding drilling of the first and second section, consume an equal amount of time for both investigated cases. Project financials with a detailed comparison of both investigated cases can be found in section 4.2.

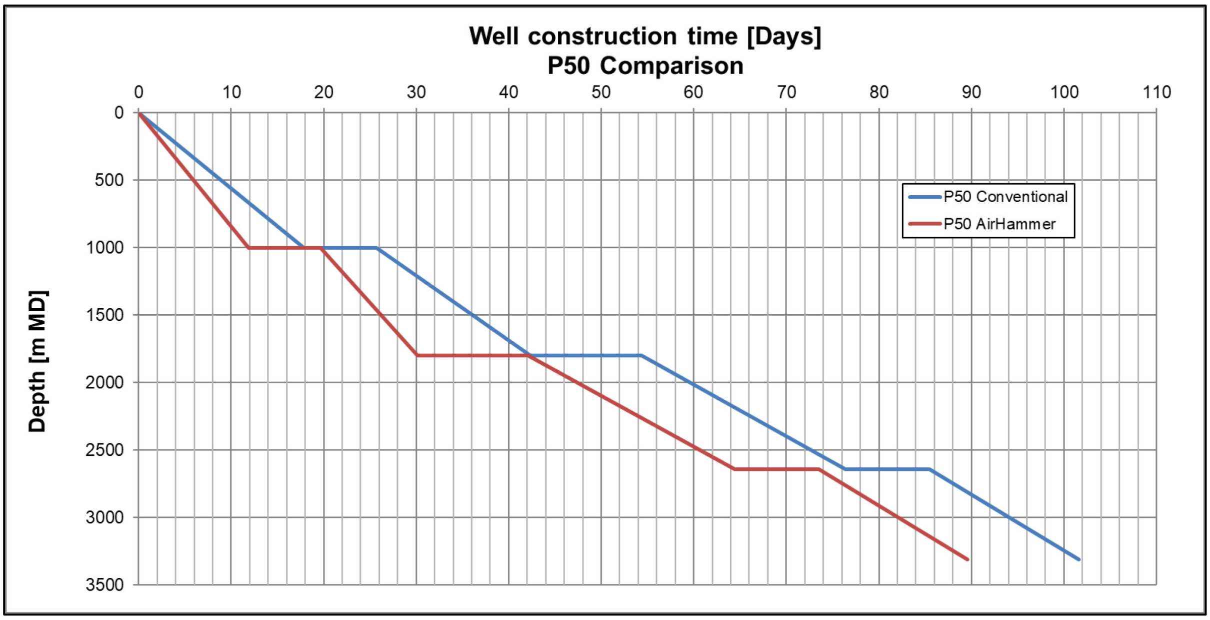

Figure 66: Time vs. Depth Diagram (comparison)

4.1.4 Sensitivity Analysis

A sensitivity analysis is performed to assess the impact of input variables on the simulation output. A commonly way to visualize this is by Tornado charts. In this thesis, the sensitivity is shown using the Spearman rank order correlation coefficient. The correlation coefficient value shows how strong two variables are related. Values between -1 and 1 are possible. A value of zero depicts that no correlation exists. One value increases if the other does for positive correlation coefficients, while one value increases and the other decreases for negative correlation coefficients. Within Figure 67, ROP input is depicted with a highly negative correlation coefficient. This can be confirmed by the fact that an increase of ROP will eventually lead to lower section drilling times and, therefore, a lower overall well construction time. This is precisely the other way around for DFT. ROP and DFT variations have the most substantial impact on total well construction time, followed by the process of drilling the shoe and performing a formation integrity test (FIT). This is caused by the fact that the drilling process contributes most to the total well construction time and the high variability of these input variables.

ROP, DFT, and WOC /BOP /Pick up pipe have the most significant influence on the construction time of the first section (Figure 68). This can be explained by way of constructing the first section. The installation of the wellhead and subsequent installation of the BOP for the first section can only begin when the cement is set because the surface casing is not hung into a casing hanger. Wellhead and BOP installation works contribute largely to the first section construction time, which is why a significant variation within the input data set has a tremendous impact on section construction time.

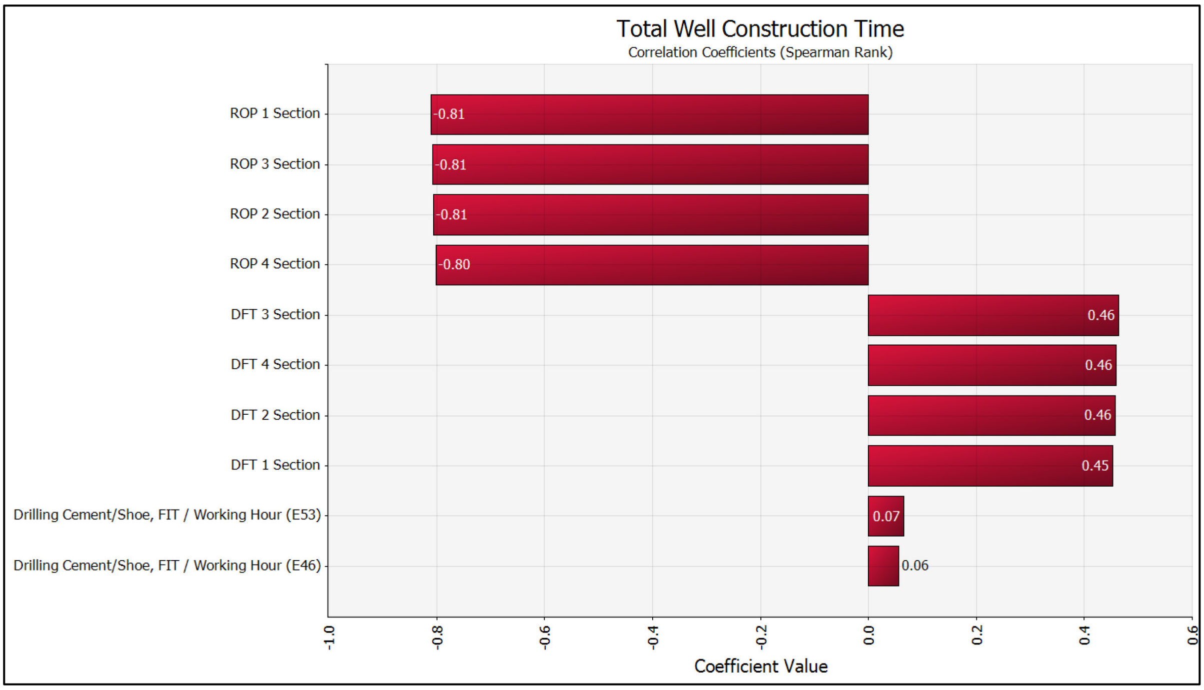

Figure 67: Tornado chart with correlation coefficients for the total well construction time (conventional)

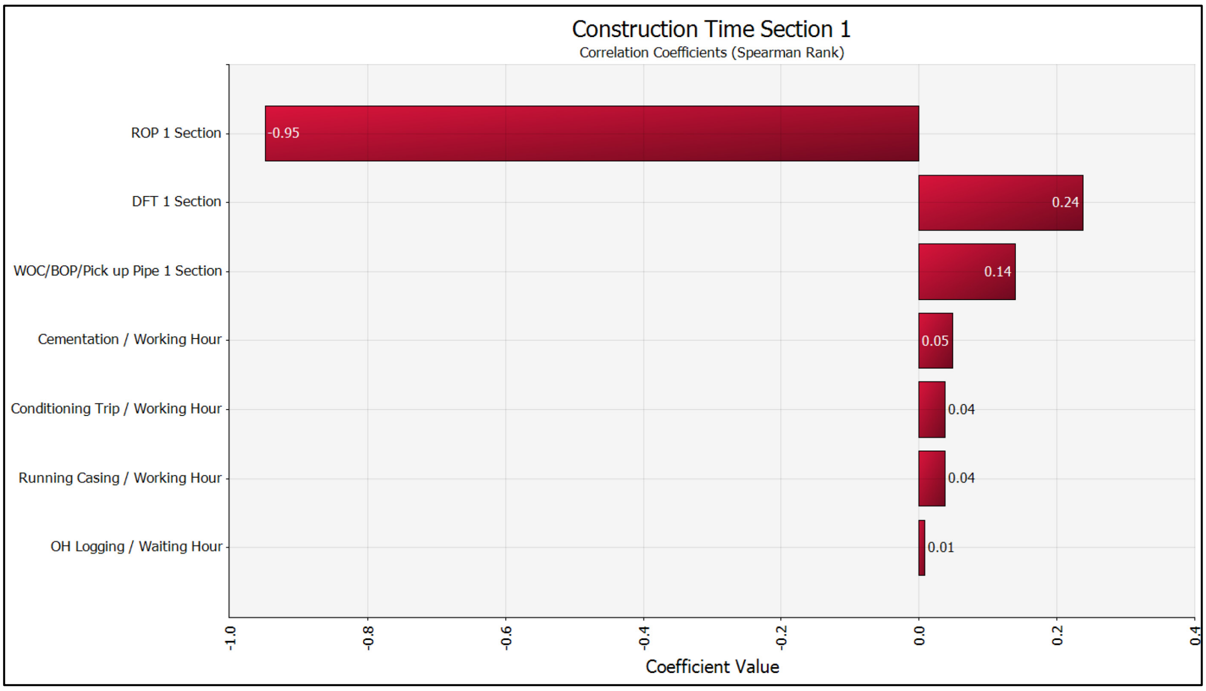

Figure 68: Tornado chart with correlation coefficients for section 1 construction time (conventional)

Same statements as for the conventional approach hold for the air hammer approach. However, some minor deviations are investigated. ROP of the first and second section (air hammer sections) show to have a slightly lower impact on total well construction time when compared to the entirely conventional approach (compare Figure 67 and Figure 69). This can be explained by two things: First, due to the higher assumed ROP of the air hammer, the overall drilling time within the air hammer sections is lower, thus leading to a smaller contribution to the total well construction time. Second, no data set from offset wells for drilling with an air hammer is available. Manufacturer expectations for drilling the respective sections were considered by assigning a normal distribution function to the air hammer ROP. Function values are 8 m/h (Mode, Mean, Median), 6 m/h (P10) and 10 m/h (P90), and a standard deviation of 1.56 for the first section ROP. 10 m/h (Mode, Mean, Median), 8 m/h (P10), and 12 m/h (P90) with a standard deviation of 1.56 was assumed for the second section ROP. These normal distribution functions have relatively low variations compared to the distribution functions assigned for the ROP of the third and fourth section. ROP variations of the third and fourth section show to have the most considerable influence on the total well construction time.

Section one construction time shows the same behavior as already explained for the conventional approach.

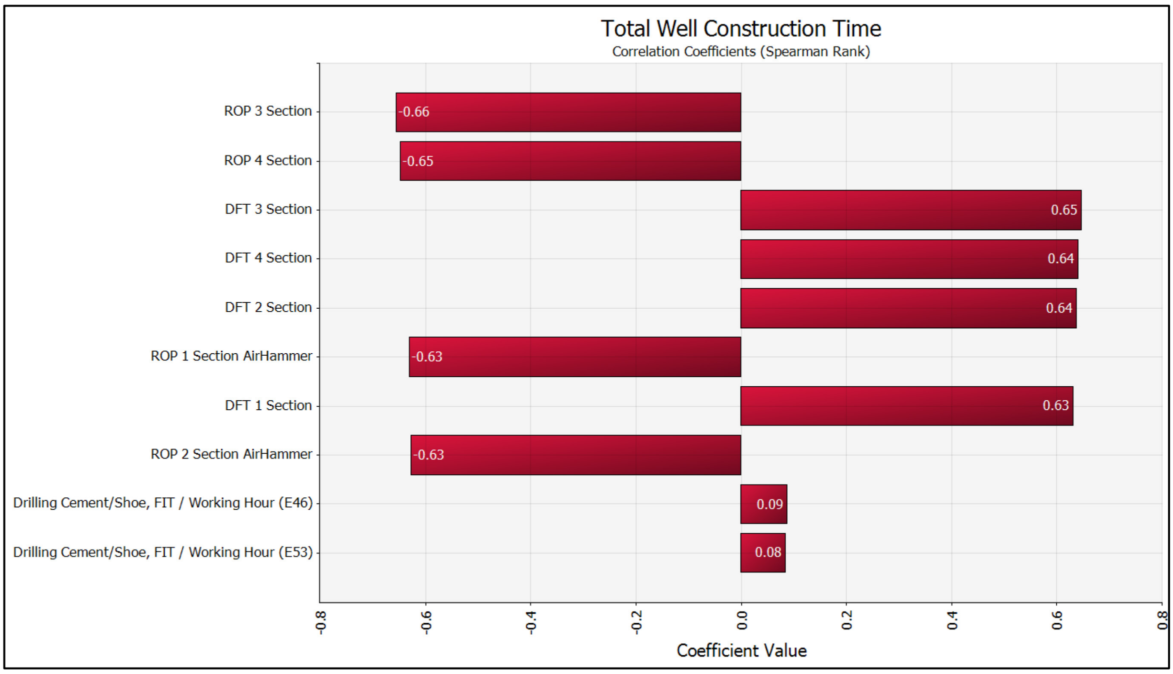

Figure 69: Tornado chart with correlation coefficients for the total well construction time (air hammer)

4.2 Outcome of the Economic Analysis and Cost Estimation

This chapter visualizes and discusses the economic analysis outcome to compare the possible financial benefits generated by a change from conventional drilling towards air hammer drilling for the planned basement drilling project. The general principles and workflows behind the now discussed results are explained throughout section 3.7.3 of this thesis. First, the estimated cost for the air hammer related lots will be displayed and evaluated. In the end, the potential cost savings in case of air hammer drilling are presented and discussed. All analyses will be based on the P70 case.

4.2.1 Air Hammer Drilling Cost

A presentation and discussion of the estimated associated cost for the introduced air hammer lots are given in this section. The total estimated cost for the air hammer lots for drilling the first and second sections of the planned project range from 2,758,276 € in the P10 case up to 4,793,442 € in the P70 case (see Figure 70).

Air Hammer Lots - Cost Overview			
Description	**Cost (1. Section & 2. Section) Best Bidder**		
	P10	**P50**	**P70**
01.2 - Air Package	845,578 €	1,073,263 €	1,330,453 €
01.3 - DTH Air Hammer incl. DTH Button Bits	512,652 €	751,997 €	908,866 €
06 - Drilling Fluid	33,416 €	39,880 €	47,059 €
xx - Drilling Foam Additives and Equipment	427,779 €	479,166 €	566,678 €
Energy Cost - Air Hammer	938,852 €	1,417,692 €	1,940,387 €
Total Air Hammer Lots	***2,758,276 €***	***3,761,999 €***	***4,793,442 €***

Figure 70: Estimated cost summary air hammer lots

41% of the total estimated air hammer lots cost are contributed by the diesel cost to operate the compressor and booster units and the electricity cost to operate the rig. Please refer to section 3.7.3 headline Lot xx – Energy for a discussion on the used approach to estimate the diesel and electricity consumption. The air package contributes 28% to the total cost estimated for the air hammer lots. By far, the most considerable contribution to the overall cost for this lot is the daily operational rate of the entire air package. Other large contributions to the overall cost of this lot are given by the personnel cost and mobilization and demobilization of the entire equipment related to the air package. The DTH air hammer, including the button bits, contributes 19% of the total cost estimated for the air hammer lots. The combined cost for the down the hole button bits estimated for the first and second sections has the largest contribution to this lot's overall cost. The second-largest contribution are the cost for the air hammer (purchase price) for the first and second section, followed by personnel cost. While the cost for the drilling fluid service are minor (1% of total cost), the cost for drilling foam additives and equipment makes 12% of the total estimated cost for the air hammer lots. They are mainly driven by the cost of surface equipment and chemical additives. The largest contribution to this lot's total cost is given by the mobilization and demobilization of the air drilling cyclone (oversea transport) followed by the combined cost for air hammer oil, foaming agent, and defoaming, and viscosifying agent. The rental of subsurface equipment does not significantly impact this lot's overall cost. An overview of the cost distribution is reflected in Figure 71.

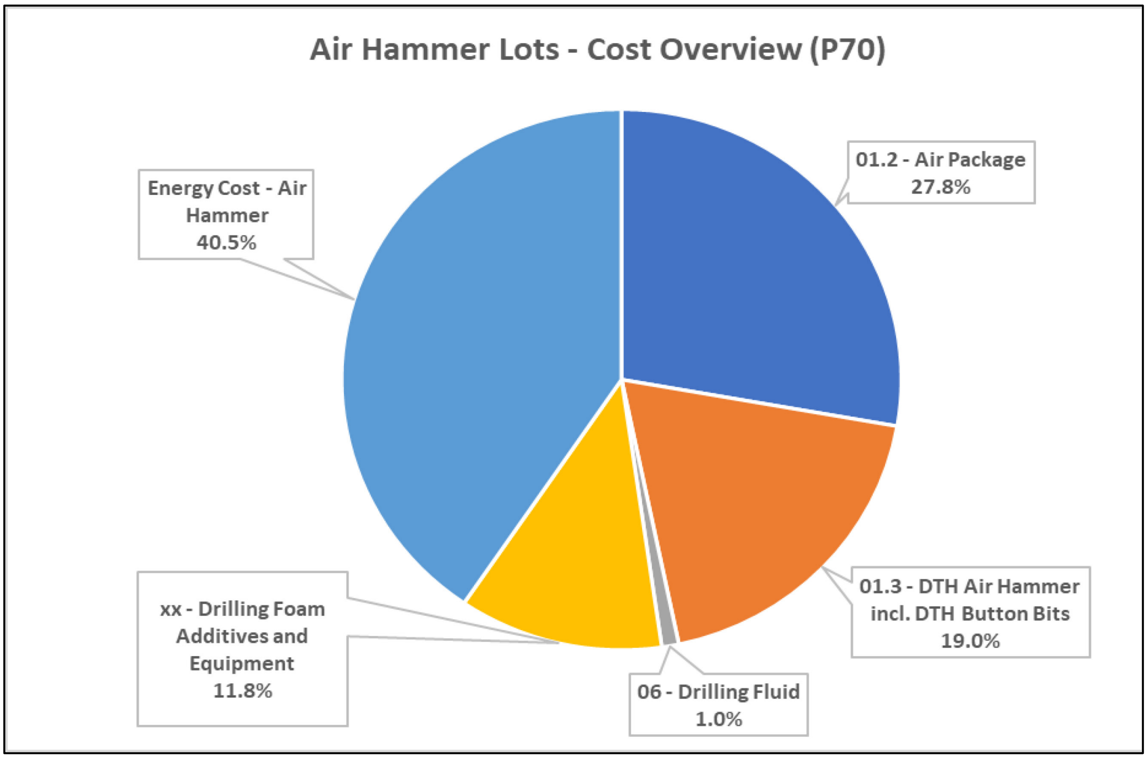

Figure 71: Air hammer lots cost distribution

4.2.2 Economic Analysis Summary

The approach used for a first estimation of the economic viability of air hammer drilling is described and visualized in section 3.7.3 (see Figure 59)

The estimated incurred project cost for relevant and air hammer lots in case of air hammer drilling are presented in Figure 72. In contrast, the estimated cost for these lots in case of conventional drilling are shown in Figure 74.

Relevant Lots - Cost Overview (Air Hammer)			
Description	**Overall Project Cost (1st to 4th Section) Best Bidder**		
	P10	**P50**	**P70**
01 - Drilling Service	3,544,017 €	4,196,263 €	4,921,640 €
05 - Directional Drilling	472,823 €	565,251 €	624,346 €
06 - Drilling Fluid	222,783 €	252,430 €	278,841 €
11 - Drill Bits	129,264 €	221,283 €	272,801 €
16 - Mud Logging	248,884 €	504,936 €	755,934 €
01.2 - Air Package	845,578 €	1,073,263 €	1,330,453 €
01.3 - DTH Air Hammer incl. DTH Button Bits	512,652 €	751,997 €	908,866 €
06 - Drilling Fluid	33,416 €	39,880 €	47,059 €
xx - Drilling Foam Additives and Equipment	427,779 €	479,166 €	566,678 €
Energy Cost - Air Hammer	938,852 €	1,417,692 €	1,940,387 €
Total Air Hammer	***7,376,047 €***	***9,502,163 €***	***11,647,004 €***

Figure 72: Cost estimation summary for relevant and air hammer lots during air hammer drilling

Figure 73 shows the cost distribution of all considered lots in case of air hammer drilling. The high share of energy costs on total costs (17% Energy Cost – Air Hammer) reflects the high energy requirements for air hammer drilling, which can also be confirmed by literature. The costs for the drilling service are well below 50% with an estimated 42% share of total costs. In contrast the costs for this lot in case of conventional drilling (see Figure 75) are estimated to be 54% of total costs. This can be explained by the higher estimated ROP and therefore reduced section drilling times in case of air hammer drilling.

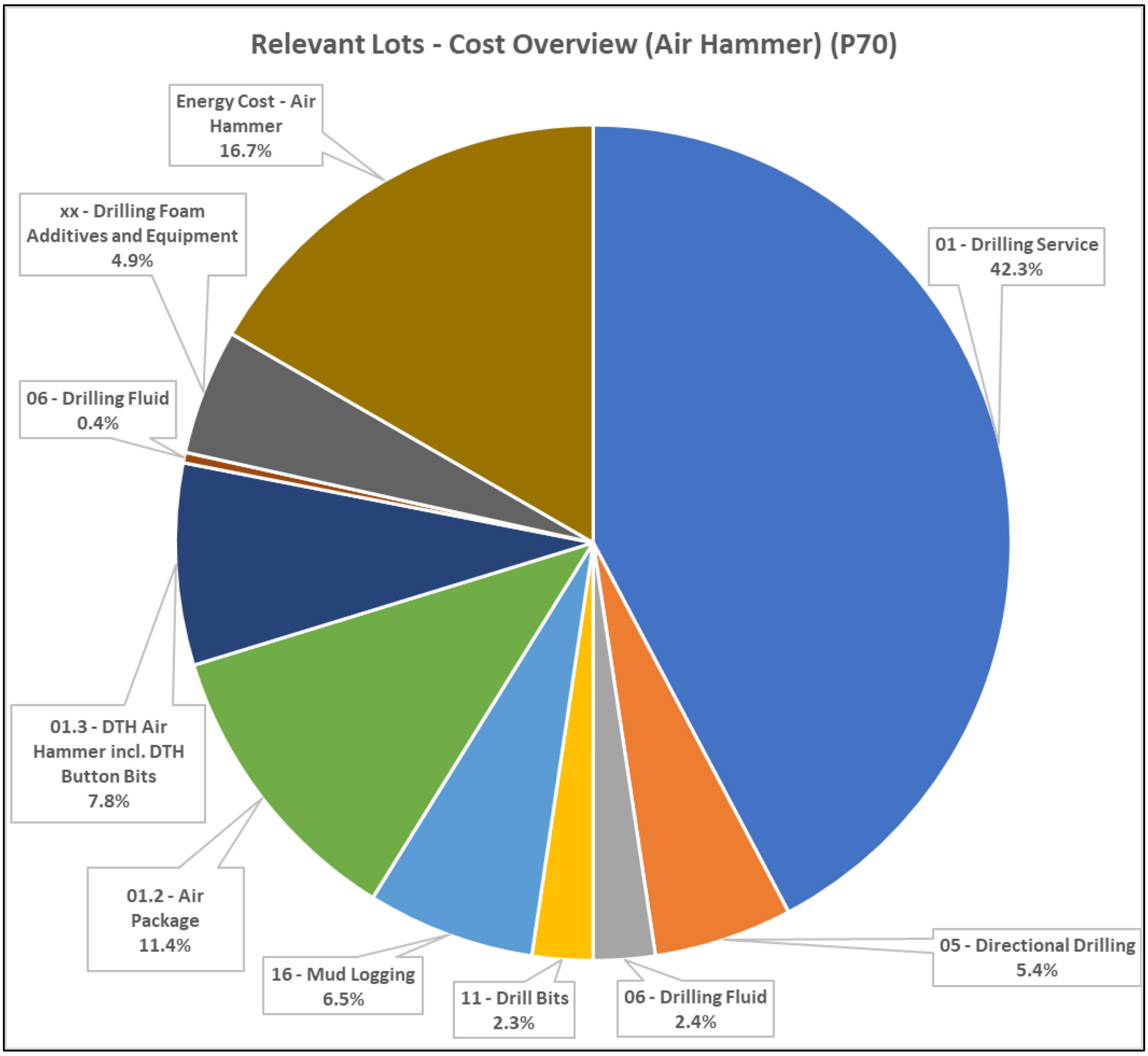

Figure 73: Cost distribution for relevant and air hammer lots in case of air hammer drilling

Relevant Lots - Cost Overview (Conventional)			
Description	Overall Project Cost (1^{st} to 4^{th} Section) Best Bidder		
	P10	P50	P70
01 - Drilling Service	4,605,843 €	5,345,493 €	5,910,526 €
05 - Directional Drilling	969,859 €	1,155,857 €	1,272,986 €
06 - Drilling Fluid	387,201 €	532,253 €	577,103 €
11 - Drill Bits	438,983 €	852,207 €	1,043,873 €
16 - Mud Logging	306,130 €	631,565 €	957,000 €
Energy Cost - Conventional	860,521 €	1,055,820 €	1,151,030 €
Total Conventional	***7,568,537 €***	***9,573,195 €***	***10,912,518 €***

Figure 74: Cost estimation summary for relevant lots during conventional drilling

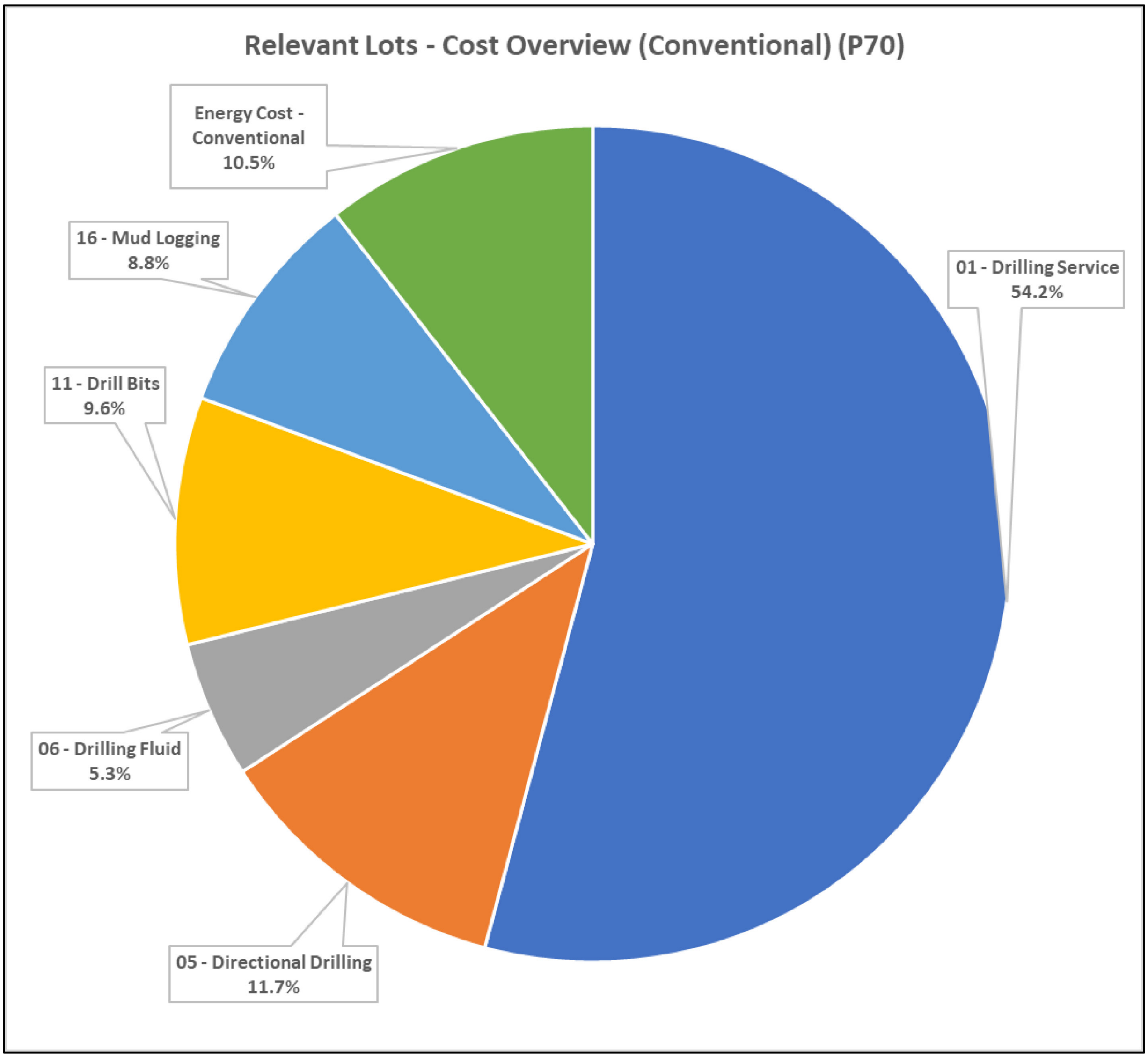

Figure 75: Cost distribution for relevant lots in case of conventional drilling

The economic viability of air hammer drilling for the planned project can be obtained by comparing the total estimated cost for air hammer drilling (Figure 72) with the total estimated cost for conventional drilling (Figure 74). The results of this comparison can be found in Figure 76. It is visible that the estimated project cost is higher in case of utilizing the air hammer drilling approach compared to the conventional approach. The high difference between the P10 and P70 air hammer cost is mainly dominated by the estimated diesel consumption and associated diesel cost, which is very conservative for the P70 case. The P10 and P50 estimations yield small potential savings in case of air hammer drilling. Nevertheless, the overall numbers show that air hammer drilling's economic viability may not be given for this project if regarding the P70 case.

Economic Viability Air Hammer Drilling			
Description	**Estimated Cost**		
	P10	**P50**	**P70**
Air Hammer Cost	7,376,047 €	9,502,163 €	11,647,004 €
Conventional Cost	7,568,537 €	9,573,195 €	10,912,518 €
Total Estimated Savings Air Hammer Drilling	***192,490 €***	***71,032 €***	***-734,485 €***

Figure 76: Economic viability air hammer drilling

4.2.3 Discussion of the Results

The economic analysis results seem to be very surprising since someone would expect lower drilling costs in case of air hammer drilling, as often stated within the literature. However, one drilling approach's economic viability is closely linked to the unique characteristics and requirements of a project and can therefore not be generalized.

For this project, the selected well design is optimized in terms of safety (exploratory project) and customized for a conventional drilling approach. The very long large diameter first and second sections (23" and 16") are usually not suitable for air hammer drilling. Very high air volumes are required to guarantee sufficient uphole velocity for adequate cutting transport and hole cleaning. The high required flowrates call for large air packages (compressor and booster units). Large air packages come with a high rental and diesel cost, which influences the cost per meter drilled. Furthermore, it is well known and described in this thesis that air hammer drilling works very well in dry formations. The air hammer's efficiency is significantly impacted by backpressure on the hammer created by a possible formation water influx. For this project, high formation water influx is expected, so additional measures such as booster units pressure rated high enough to assist in unloading the borehole, and foam drilling were considered. The foam drilling requirement makes the project more complicated and more expensive since additional chemicals, and equipment components are required. In addition to the additional estimated cost for foam drilling, the handling of huge quantities of foam and formation water on surface are bearing significant technical challenges. Other room for improvement lies within the optimization of the tendering for air hammer drilling related services. Even though clear structured and well-designed tender documents for the required air hammer related services were sent out, the responses were limited. For example, the drilling fluid companies participating in this tender process could not provide the requested services and equipment related to air and foam drilling. This is usually done by specialized companies and should therefore be attached to the air hammer tender documents or being tendered separately to receive more competitive offers in terms of prices. A more general conclusion related to the tender process is that the market for air hammer related services is very limited within Europe. It can be concluded that a different approach would be to directly contact the respective companies and suppliers with a technical scope of work, allowing close collaboration on the respective required services to obtain more competitive offers. Moreover, the minimum technical requirements (hook load, top drive torque rating, solid control system, mud pumps) for the drilling rig were selected to be suitable for the technical requirements of this particular project. This excluded the advantage that smaller drilling rigs can often be used for air hammer drilling operations since the requirements for the mud pumps, torque rating of the top drive and hook load rating are usually lower. However, special technical and geological circumstances bounded to this project require conventional drilling within the 3rd and 4th section of the well. High top drive torque as well as hook load requirements are expected for the deep 3rd and 4th well section. Furthermore, high hook load requirements for running of the long 18.5/8" surface casing and 13.3/8" liner have been calculated. Lastly, high energy requirements in terms of diesel for the air package greatly influence the economics of the air hammer approach. The air package's overall operational cost could be improved using electrical driven compressor and booster units (depending on the market availability).

To summarize, the technical and geological boundary conditions of the planned geothermal exploration project require a well design which is, due to the size and length of large diameter well sections, not optimally suited for air hammer drilling.

5 Summary and Conclusion

The thesis gives a well-structured overview of the technical and financial most attractive possibilities for geothermal basement drilling, focusing on applying alternative air and water hammer drilling technologies. An extensive literature review provides fundamental knowledge for conducting the economic analysis, which forms a major part of the thesis. Geological challenges, conventional rotary drilling within the crystalline basement, introduction of the alternative air and water hammer technologies with their advantages and disadvantages are, amongst others, covered within the literature review. Additionally, the critical topic of drilling fluid systems for basement drilling, covering topics such as air and foam drilling, is highlighted based on recent literature. Required surface and subsurface equipment to establish a functional air hammer system is described based on profound and most recent literature.

The second part of the thesis covers the drilling method selection process, where the decision for the air hammer and against the water hammer system is described. Furthermore, the technical implementation of an air hammer system with all relevant surface and subsurface equipment, covering the air package and air hammer, and recommended operating parameter, is discussed regarding an ongoing geothermal basement drilling project. The rotary drilling approach, which acts as a conservative base case for the project, is well described to understand the economic analysis's basic input. Another part of the thesis covers the elaboration of tender documents for air hammer related services. The technical scope of work and the most critical technical parameter to establish the tender documents could be obtained from the theoretical and practical work conducted and explained within this thesis. The tender documents allowed to receive offers from the industry, which contained the relevant prices acting as input to the economic analysis. A probabilistic time estimation based on relevant data was conducted for the conventional rotary drilling and the air hammer drilling approach. The generated time estimation data was utilized for the economic analysis. This thesis's main outcome is an economic analysis based on data from an ongoing geothermal project, comparing estimated cost for the conventional and the air hammer drilling approach. The economic analysis is based on relevant project data and recent industry prices for equipment and services obtained through a tendering process.

The result of the economic analysis showed that the economic viability for air hammer drilling is most likely not given for the investigated planned project. However, this is linked to special project circumstances discussed in section 4.2.3 of the thesis. Air hammer and especially water hammer drilling systems will become more important for geothermal basement drilling projects in the future. The thesis highlighted the potential of percussive drilling systems within the crystalline basement to improve the ROP and, therefore, the project's overall economics. However, depending on the project circumstances economic viability of those systems may be given or not. Particular attention should be paid towards improving the water hammer drilling technology, since the shortcomings of the air hammer technology with its large air package and subsequent large energy requirements, as well as difficulties with formation water influx, are no issues for the water hammer system. However, availability of large hydraulic hammer systems, as well as its reliability and ability to deal with finest particles in the drilling water, need to be improved. A hydraulic mechanical hammer (see section 2.7) was briefly described within the thesis. This system, in combination with aerated drilling, has the potential to significantly increase the ROP and therefore provides a promising alternative to water and air hammer systems.

Further future works related to air hammer drilling within the crystalline basement should include the setup of a numerical solver for adequate air volume and pressure requirements determination depending on borehole geometry and BHA components, as well as the design of an erosion-resistant finish for the blooie line and air drilling separator.

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Abbreviations

AFE	Authorization for Expenditure
AIC	Akaike Information Criteria
API	American Petroleum Institute
BHA	Bottom Hole Assembly
BIC	Bayesian Information Criteria
BOP	Blowout Preventer
CDE	Conical Diamond Element
DBR	Damage beyond Repair
DC	Drill Collar
DFT	Drilling Flat Time
DOG	Drilling on Gauge
DP	Drill Pipe
DTH	Down the Hole
DWOP	Drill Well on Paper
EGS	Engineered Geothermal System
ESP	Electrical Submersible Pump
EU	External Upset
FE	Finite Element
FH	Full Hole
FIT	Formation Integrity Test
HSI	Hydraulic Horsepower per Square Inch
HWDP	Heavy Weight Drill Pipe
IADC	International Association of Drilling Contractors
ID	Inner Diameter
IEU	Internal and External Upset
IPS	In Production Setting
IU	Internal Upset
LCM	Lost Circulation Materia
MD	Measured Depth
MPD	Managed Pressure Drilling
MWD	Measurement while Drilling
NADF	Non-Aqueous Drilling Fluids
NMDC	Non-Magnetic Drill Collar
NC	Numbered Connection
NOV	National Oilwell Varco
OBM	Oil Based Mud
OD	Outer Diameter
ORC	Organic Rankine Cycle
PAC L (R)	Polyanionic Cellulosic Polymer L (R)
PBR	Polished Bore Receptacle
PDC	Polycrystalline Diamond Compact
PDM	Positive Displacement Motor
RCD	Rotating Control Device
ROP	Rate of Penetration
RPM	Revolutions per Minute
RSR_DA	Ram, Spool, Double Ram, Annular Preventer
RSS	Rotary Steerable System
SBM	Synthetic Based Mud
SPM	Strokes per minute
TCI	Tungsten Carbide Inserts
TFA	Total Flow Area

TSP	Thermally Stable PDC
TVD	True Vertical Depth
UBD	Underbalanced Drilling
UCS	Uniaxial Compressive Strength
WBM	Water Based Mud
WOB	Weight on Bit
WOC	Wait on Cement

Nomenclature

Q_{go}	Volumetric flowrate of gas at standard conditions [scf/min]
D_h	Borehole diameter [in]
D_p	Drill pipe diameter [in]
H	Vertical length [ft]
R_p	ROP [ft/h]
x	Required air volume [m^3/min]
D	Borehole diameter [mm]
d	Drill pipe diameter [mm]

Appendices

Appendix A – Rock Mechanical Properties

Figure 77 shows mechanical strength parameter for selected lithological rock groups.

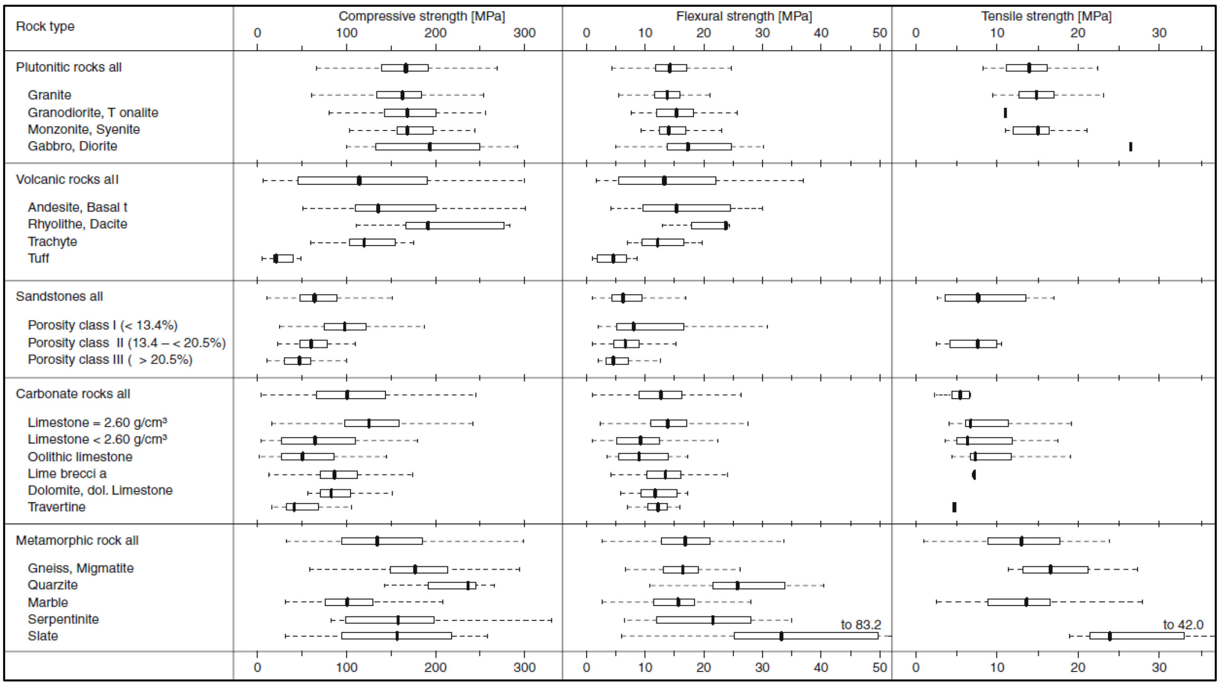

Figure 77: Statistical analysis of mechanical strength parameters for lithological groups[1]

Figure 78 to Figure 80 shows mechanical properties of selected rocks. Values in brackets represent the anisotropic values.

[1] Siegesmund and Dürrast 2011. *Physical and Mechanical Properties of Rocks:* 97–225. https://doi.org/10.1007/978-3-642-14475-2_3.

Commercial name	Country of origin	Rock type	Compressive strength (MPa)	Flexural strength (MPa)	Tensile strength (MPa)	Abrasion strength $(cm^3/50\ cm^2)$	Young's modulus (static) (GPa)
Ben Tak White	Thailand	Granite	183.7 (14.0)	19.7 (19.7)	10.6 (14.4)	4.7 (6.8)	28.0 (17.9)
Muang Tak Orange 1	Thailand	Granite	184.8 (25.8)	16.9 (40.5)	8.9 (29.2)	4.0 (7.2)	28.1 (14.8)
Kösseine	Germany	Granite	195.0 (2.6)	20.1 (20.3)	11.9 (12.7)	5.7 (2.8)	27.5 (17.8)
Antrona	Italy	Granite	208.0 (6.5)		12.4 (20.3)	7.4 (10.7)	15.9
Rojo Dragon	Argentina	Granite	194.4 (1.3)	13.3 (13.3	6.5 (10.8)	4.2 (4.0)	32.5
Padang	China	Granodiorite	222.0 (6.5)	21.0 (11.9)	12.8 (8.9)	7.1 (3.6)	30.6 (19.3)
Ben Tak Blue	Thailand	Quartz-monzonite	174.5 (4.0)	28.3 (15.0)	13.8 (14.9)	8.4 (11.9)	28.5 (7.2)
Salmon Red	Uruguay	Syenite		14.38 (13.36)	8.9 (3.5)	2.81 (21.4)	
Artigas	Uruguay	Syenite			5.76 (20.6)	3.41 (4.1)	
Nero Absoluto	Uruguay	Dolerite	358.1 (2.9)	49.72 (16.4)	17.87 (15.7)	2.25 (10.6)	27.1 (35.6)
Anzola	Italy	Gabbro	208.0 (16.1)	14.9 (43.1)	9.6 (27.6)	7.8 (20.7)	28.5 (23.6)
Nero Impala	South Africa	Gabbro-norite	235.0 (14.5)	17.1 (5.9)	10.7 (8.0)	6.8 (12.9)	32.8 (35.3)
Negro Riojano	Argentina	Gabbro	200.2 (6.7)	24.6 (3.8)	10.9 (1.7)	3.96 (0.3)	
Balmuccia	Italy	Perodotite	243.0 (9.4)	24.6 (29.7)	13.1 (10.0)	5.7 (10.5)	37.7 (17.4)
Löbejün	Germany	Rhyolite	188.5	19.3 (17.6)	10.3 (31.2)	5.0	
Stardust Grey	Argentina	Rhyolite	207.4 (3.7)	21.5 (29.3)	10.3 (12.9)	7.3 (63.5)	29.6
Monte Merlo	Italy	Trachyte					
Drachenfels	Germany	Trachyte					
Weibern	Germany	Phonolite tuff	11.36		1.6		4.8
Rochlitz	Germany	Rhyolite tuff	23.6	2.7	3.8 (28.9)	11.8	16.7
Phanom Sarakham Grey	Thailand	Gneiss	194.6 (4.4)	19.1 (20.5)	10.9 (18.9)	4.5 (8.7)	29.2 (5.2)
Azul Tango	Argentina	Gneiss	212.3 (12.2)	23.5 (2.0)	9.7 (29.8)	3.9 (10.5)	36.6
Calanca	Italy	Gneiss	186.0 (22.3	15.4 (73.4)	9.3 (54.8)	8.1 (15.9)	25.0 (10.8)

Figure 78: Mechanical properties of selected rocks (a)[1]

Commercial name	Country of origin	Rock type	Compressive strength (MPa)	Flexural strength (MPa)	Tensile strength (MPa)	Abrasion strength $(cm^3/50\ cm^2)$	Young's modulus (static) (GPa)
Verde Andeer	Italy	Gneiss	176.0 (28.0)	15.3 (72.6)	11.4 (52.8)	7.4 (22.9)	22.1 (7.9)
Serizzo Monte Roas	Italy	Gneiss	169.0 (8.0)		9.8 (54.1)	7.9 (13.7)	20.7 (6.5)
Wang Nam Kiew Black	Thailand	Hornblendite	125.5 (8.8)	11.5 (32.5)	6.8 (40.2)	7.1 (14.8)	28.7 (24.6)
Franco Veteado	Argentina	Migmatite	112.1 (16.0)	11.9 (17.3)	8.2 (16.6)		23.3
Rosa Estremoz	Portugal	Marble	81.2 (18.5)	16.4 (31.0)	6.8 (20.0)	24.9 (7.4)	16.4
Carrara	Italy	Marbe			4.5 (48.8)		
Carrara	Italy	Marble					
Phran Kratai Grey	Thailand	Marble	122.1 (46.8)	25.3 (59.9)	8.9 (44.4)	15.0 (13.0)	30.4 (9.1)
Azul Cielo	Argentina	Marble	50.2 (2.7)	5.9 (24.7)	3.5 (7.7)		30.8
Azul Imperial	Brazil	Muartzite	281.0 (5.8)	28.4 (41.9)	18.3 (21.9)	4.3 (8.5)	34.2 (14.3)
Camine Rulo	Uruguay	Slate			13.54 (93.1)	11.25 (19.5)	
San Luis Slate	Argentina	Slate	172.4 (33.8)	37.5 (99.3)	13.4 (62.7)	13.8 (67.2)	37.6
Theuma	Germany	Slate	89.7	3.3		31.3	
Globegerina	Malta	Limestone	26.4 (94.4)	1.1−4.7	3.03 (17.5)		21.0
Caliza Amarilla	Argentina	Limestone	84.0 (19.6)	11.4 (13.3)	4.5 (21.0)	24.8 (24.0)	
Dolomita Dorada	Argentina	Dolomitic limestone	194.1 (11.9)	21.3 (22.8)	10.2 (7.6)	21.1 (3.4)	
Mae Phrik Yellow	Thailand	Limestone	125.3 (6.4)	14.7 (11.0)	8.5 (18.9)	9.9 (9.1)	29.3 (23.3)
Soskut	Hungary	Limestone					
Kuacker	Germany	Limestone	82.5	12.6	5.5	23.8	
Thüster	Germany	Limestone	25.0		7.0		
Bad Langensalza	Germany	Travertine	55.0 (52)	7.9 (10.8)	5.6 (34.6)	22.3	47.2 (10.2)
Baumberger	Germany	Sandstone-like limestone	50.0	11.0	4.1	19.1	19

Figure 79: Mechanical properties of selected rocks (b)[2]

[1] Siegesmund and Dürrast 2011. *Physical and Mechanical Properties of Rocks:* 97–225. https://doi.org/10.1007/978-3-642-14475-2_3.

[2] Siegesmund and Dürrast 2011. *Physical and Mechanical Properties of Rocks:* 97–225. https://doi.org/10.1007/978-3-642-14475-2_3.

Commercial name	Country of origin	Rock type	Compressive strength (MPa)	Flexural strength (MPa)	Tensile strength (MPa)	Abrasion strength ($cm^3/50\ cm^2$)	Young's modulus (static) (GPa)
Anröchte	Germany	Sandstone-like limestone	85.0	21.9		19.8	
Bad Bentheim	Germany	Sandstone	50.3	4.2	2.8	16.4	
Schleerither	Germany	Sandstone	76.8 (17.8)		6.8		
Weser	Germany	Sandstone	149.8 (5.5)	21.3	8.4	12.3	
Sikhiu Brown	Thailand	Sandstone	147.5 (20.5)	16.7 (35.5)	8.7 (7.7)	9.9 (9.6)	18.4 (5.1)
Pakchong Green	Thailand	Sandstone	103.2 (20.0)	10.7 (39.2)	5.7 (25.2)	12.9 (28.3)	13.5 (19.1)
Tacuarembo	Uruguay	Sandstone	32.7 (28)	4.07 (16.6)	2.4 (56.6)	56.4 (24.2)	5.3 (50)

Figure 80: Mechanical properties of selected rocks (c)[1]

Appendix B – Roller Cone IADC Classification

Figure 81 shows the IADC classification for roller cone bits.

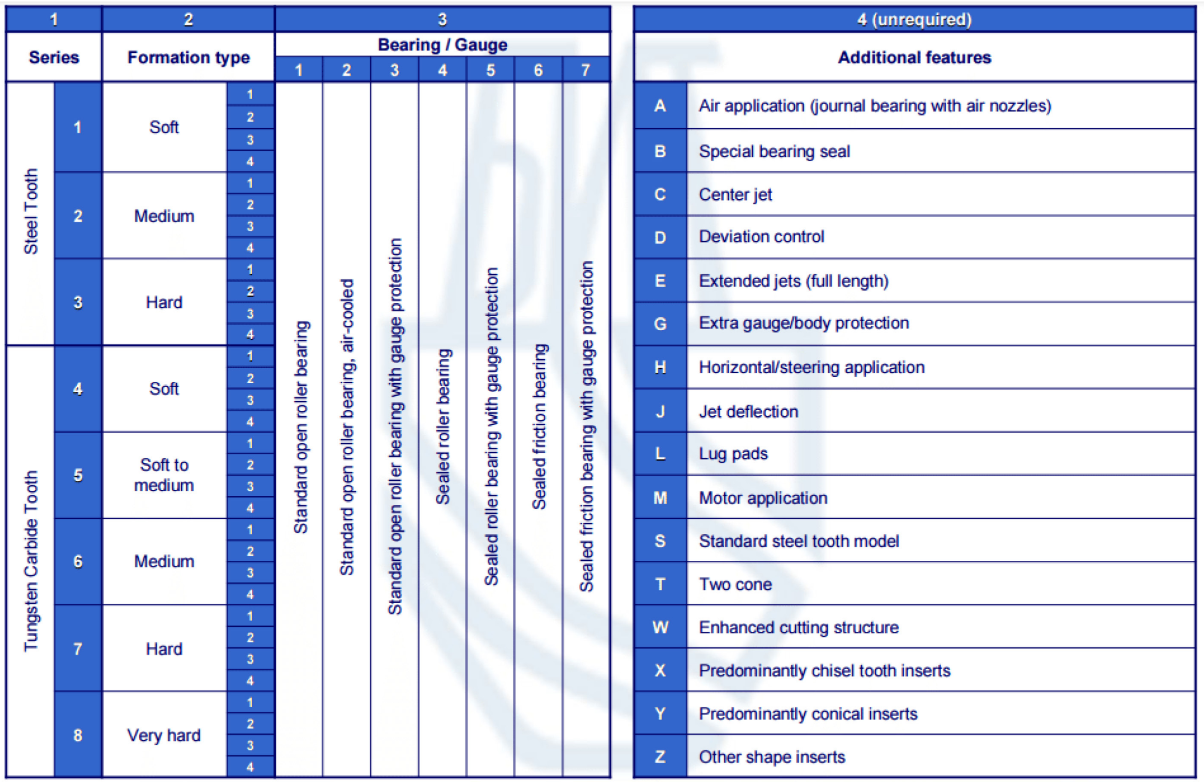

Figure 81: IADC classification for roller cone bits[2]

[1] Siegesmund and Dürrast 2011. *Physical and Mechanical Properties of Rocks:* 97–225. https://doi.org/10.1007/978-3-642-14475-2_3.

[2] 2020. *IADC CLASSIFICATION FOR ROLLER CONE BITS*, 2 May 2020, http://bestdrillingbits.com/iadc-classification-for-roller-cone-bits/ (accessed 2 May 2020).

Appendix C - Drill Pipe and BHA Components

This A will give an introductory overview of most important BHA components (not focusing on, e.g., crossover subs) and their function, with special focus on rotary drilling within hard and abrasive formations. Functionality and interaction of the different BHA tools with each other is dependent on many factors including but not limited to the manufacturer, operating parameter, geological boundary conditions, bit type, and many more. There is no basic recipe for a basement drilling BHA, it is instead depending on many boundary conditions and should be an operational decision together with all involved service companies. However, some guidelines can be followed in other to select a suitable basement drilling BHA.

Drill Pipe

The drill pipe consists of three main components, which are the pipe body, and the threaded pin tool joint or box tool joint each welded to another end of the pipe body. Typically the pipe body is equipped with an upset towards either end to increase the wall thickness (see Figure 82). (Lyons et al. 2016)

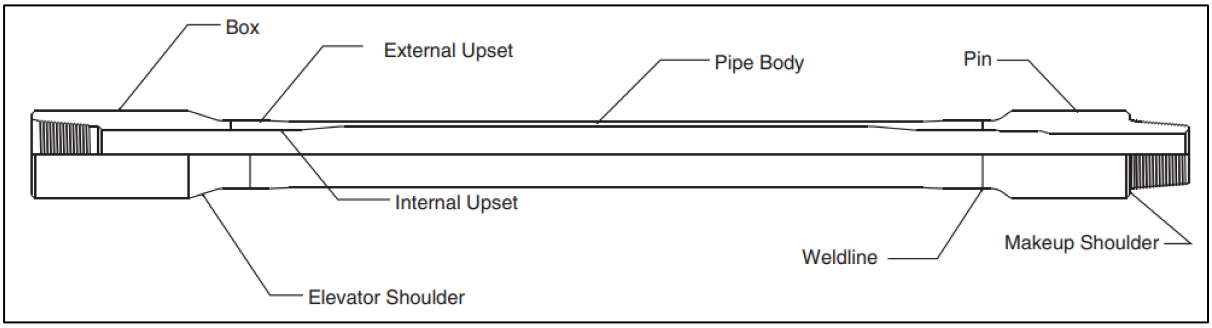

Figure 82: Typical drill pipe cross-section[1]

A drill pipe is clearly defined by the following items (Lyons et al. 2016):

- Drill pipe outer diameter (OD) [in, mm]
- Drill pipe grade which defines the minimum yield strength (e.g., API S-135 min. yield strength 135,000 psi) [psi, MPa]
- Drill pipe nominal weight without tool joint [lb/ft, kg/m]
- Drill pipe upset either internal upset (IU), external upset (EU), or internal-external upset (IEU)

Tool joint type (e.g., API connection types such as numbered connection (NC), full hole (FH), or non API types such as Grant-Prideco´s HI-Torque™ (HT™) connections) are other important drill pipe characteristic. (Gabolde and Nguyen op. 2014)

[1] Lyons et al. 2016. *Standard handbook of petroleum and natural gas engineering*, third edition. Waltham, MA: Gulf Professional Publishing.

Drill pipes, heavyweight drill pipes, and drill collar are produced in Range 1 (18-22 ft, 5.49-6.71 m), Range 2 (27-32 ft, 8.23-9.75 m) and Range 3 (38-46 ft, 11.58-14.02 m). (Lyons et al. 2016)

There are no special basement drill pipes. However, they should be selected to be suitable for high requirements during basement drilling.

Heavyweight Drill Pipes (HWDP)

Heavyweight drill pipes are of particular importance when drilling high-angle and extended reach wells where substantial portions of the drill string are in compression. The main feature of HWDP´s is their ability to, both, function under certain compressional loads without buckling and providing bending flexibility. (Lyons et al. 2016)

HWDP´s have a unique role within basement drilling operations since they can be racked without the need for lifting subs. This significantly reduces BHA handling times, compared to handling times of drill collars (DC). (Erdwerk GmbH 2020i) Therefore the option to drill without drill collar should be investigated. This can lead to substantial time savings in face of frequent necessary bit changes.

Drill Collar (DC)

Drill collar can be classified as round, spiral, and square. Spiral drill collars are designed to avoid differential sticking, while square drill collars are providing a higher stiffness. The primary purpose of DC´s is to provide weight on bit and prevent buckling while under compression. (Lyons et al. 2016) DC´s are also available as non-magnetic DC´s (NMDC´s) for the use in close vicinity of sensible downhole tools such as measurement-while-drilling (MWD) systems.

Shock Absorber (Vibration Dampener)

Axial vibrations are transmitted via the drill string to the top drive of a drilling rig, which can lead to severe damaging of components. While this surface oscillations are better noticed within shallow wells, they are dampened by the drill string within deeper sections. However, the danger for fatigue failure of drill string and BHA components remains. The primary function principle of vibration dampeners is the absorption of variable axial dynamic loads and in some cases, radial shocks via distinctive spring elements. There are various systems with different architectures and spring element types on the market. Figure 83 shows a double-action vibration and shock absorber with Belleville spring elements. The spring elements are immersed in oil in this case. The spline assembly allows transmitting high torque to the bit through its outer tube, while the inner assembly is designed to absorb vibrations. It is intended to place a shock absorber as close to the bit as possible. However, exact placement is dependent on hole deviation and BHA configuration. (Lyons et al. 2016)

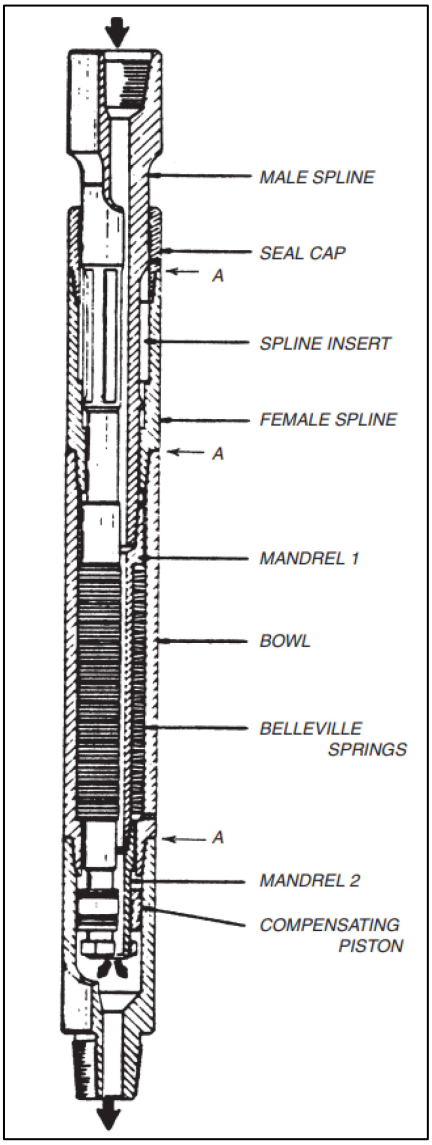

Figure 83: Belleville type shock sub[1](Lyons et al. 2016)(Lyons et al. 2016)

Use of shock subs is most beneficial when drilling in hard rock and broken formations (e.g., fractured basement rocks) using roller cone or hammer bits. Axial vibrations are created by roller cone type of bits, as the bit travels along peaks and valleys on the bottom of the borehole. Usage of a shock sub allows to increase ROP, extend the life of bearings, connections, cutting structure, and surface equipment. (Schlumberger 2017)

Shock subs should not be used in combination with a rotary steerable system (RSS). (Erdwerk GmbH 2020i)

<u>Jar and Accelerator</u>

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[1] Lyons et al. 2016. *Standard handbook of petroleum and natural gas engineering*, third edition. Waltham, MA: Gulf Professional Publishing.

Jar and accelerators within the BHA are very helpful in stuck pipe events. With the aid of a jar, stored strain energy within the drill string can be transferred into kinetic energy by releasing the detent in the jar at a given overpull. An accelerator might be used to intensify the effect of the jar and protect the drill string and surface equipment from the shock. A hollow rod-telescoping cylinder in combination with a detent mechanism that holds the rod in place until a specific force or overpull is obtained, forms the basic setup of a jar (see Figure 84). There are two types of jars with three different designs, namely drilling or fishing jars, and mechanical, hydraulic, and hydro-mechanical jars. Drilling and fishing jars are quite comparable with the exception that a drilling jar is built in a way that it can better withstand the torsional and axial loads associated with drilling operations. Jars may be single or double-acting. A double-acting jar allows for jarring down as well as jarring up operations. (Lyons et al. 2016)

Mechanical jars are activated by a certain overpull, which releases the detent. State of the art hydraulic jars use a time delay/mechanical release detent. A push or pull load applied at the surface causes the mandrel to move, either upwards or downwards, while the housing remains stationary. Two pressure pistons, opposing each other to define a high-pressure chamber, resist the movement of the mandrel. A closed triggering valve is located between the two pressure pistons. This triggering valve controls the release of fluid from the pressure chamber, and therefore the activation of the jar. For down jarring, the mandrel moves downwards with the upper-pressure piston, caused by the driller applying weight to the drill string above. A shoulder in the housing prevents the lower pressure piston from moving. Triggering of the jar occurs when the upper-pressure piston has moved sufficiently towards the lower pressure piston to open the triggering valve. Due to the sudden release of pressure, the mandrel moves until the hammer hits the anvil. The time delay from applying the load until opening of the triggering valve is achieved by a hydraulic metering mechanism controlling the speed at which the upper-pressure piston moves towards the lower. For jarring again, the tool needs to be brought back into neutral, allowing the hydraulic fluid to distribute again equally. (Weatherford 2011)

It is essential to mention that a jar can only work if the stuck point lies beneath the position of the jar within the BHA.

Service company Schlumberger gives the following placement recommendations for its double-acting hydraulic drilling jar Hydra-Jar AP (Schlumberger 2020):

- A minimum of 10% to 20% of the expected drilling jar load should be placed as a hammer weight above the jar.
- Jar should be placed outside the neutral point transition zone.
- Stabilizer should not be placed above the drilling jar. Furthermore, stabilizer should be at least 90 ft (27.4 m) away from the jar.
- Do not fire the jar with torque in the string.

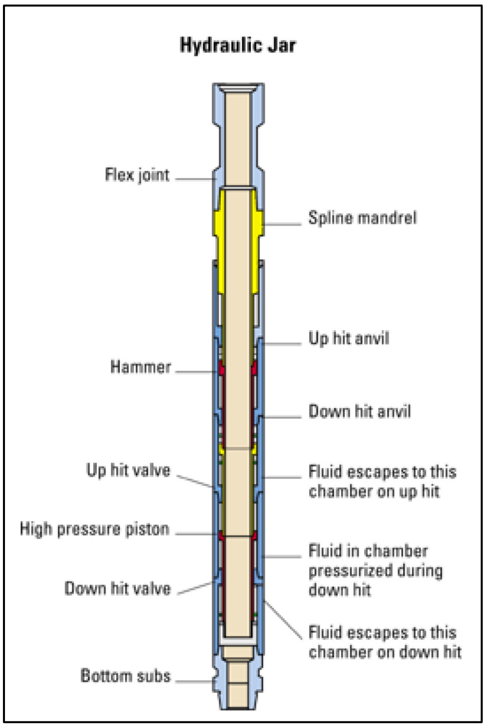

Figure 84: Schematic of a hydraulic jar[1]

Stabilizer

Stabilizers are placed within the BHA to prevent collar contact with the borehole wall, limit bit walk, minimize vibrations and bending, minimize building of key seats, and to provide equal loading of the drill bit. Furthermore, accurate stabilizer placement allows some directional control within rotary assemblies (Lyons et al. 2016).

There are three types of stabilizer designs, namely solid-type stabilizer, which are characterized by having no moving or replaceable parts (see Figure 85 and Figure 86). They either consist of a mandrel with weld-on blades (weld-on blade stabilizer) or are made of one single piece (integral blade stabilizer). Special hard facing (TCI, or diamonds) can be applied on the straight or spiral blades to enhance durability in demanding very hard and abrasive formations. The second stabilizer type are sleeve-type stabilizer (see Figure 87), which consist of a replaceable sleeve. Sleeve-type stabilizer may be designed as rotating (working like solid-type stabilizer) or non-rotating. The third group of stabilizers are reamer stabilizer (see Figure 88). They have cutting elements embedded in their fins and aid in maintaining the gauge of the borehole and to drill out doglegs and key seats in hard formations. Reamers designed with open bearings are for standard applications. In contrast, reamer with sealed bearings and pressure compensation are designed for demanding applications where higher durability of the reamer is required. (Lyons et al. 2016)

[1] Schlumberger Oilfield Glossary. *Jar*, https://www.glossary.oilfield.slb.com/en/Terms/j/jar.aspx (accessed 15 May 2020).

Figure 85: Integral blade stabilizer[1]

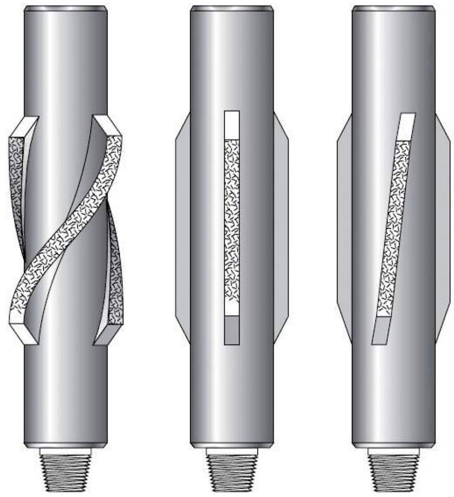

Figure 86: Weld-on blade stabilizer (from left to right: spiral blade, straight blade, straight blade with offset)[2]

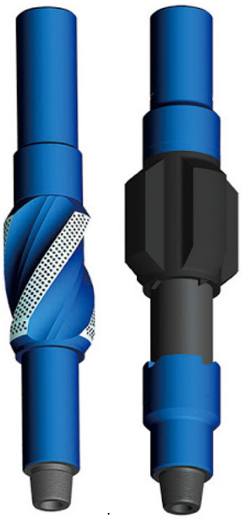

Figure 87: Sleeve-type stabilizer (left: rotating, right: non-rotating)[3]

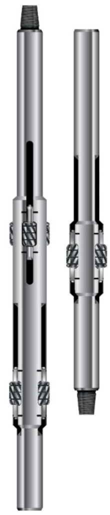

Figure 88: 6-point roller reamer (left), 3-point roller reamer (right)[4]

[1] 2020. *Integral Blade Stabilizer | Schlumberger*, 16 May 2020, https://www.slb.com/drilling/bottomhole-assemblies/reamers-and-stabilizers/integral-blade-stabilizer#related-information (accessed 16 May 2020).

[2] 2020. *Directional Drilling Technology | Stabilizers*, 29 April 2020, http://directionaldrilling.blogspot.com/2011/07/stabilizers.html (accessed 16 May 2020).

[3] 2020. *Sleeve Stabilizer-Dawnrays Co., Ltd*, 16 May 2020, http://www.dr-oiltools.com/product/274232712 (accessed 16 May 2020).

[4] 2020. *Drilling Tools Products | Roller Reamers*, 16 May 2020, https://www.drillingtools.com/rollerreamer (accessed 16 May 2020).

It is vital to discuss rotary assemblies in the context of basement drilling because they are relatively simple and robust and, therefore, cost-effective compared to conventional directional drilling systems (downhole motor (DHM) with bent sub) or rotary steerable systems (RSS). Furthermore, motorized BHA´s, even if configured at low speed and high torque (refer to section discussing positive displacement motors (PDM)) may exceed the recommended RPM range for very hard and abrasive formations, especially when pumping at high rates often required within large diameter geothermal well sections (> 16”). Another factor limiting the use of conventional directional drilling tools such as MWD´s are the elevated temperatures reached in geothermal wells.

Many factors are influencing directional control with rotary assemblies such as bit type, drilling parameter (WOB, RPM, ROP, flowrate), mechanical parameter (e.g., drill collar stiffness), formation anisotropy (e.g., foliation), dip angle of the bedding planes and formation hardness. Many of the mentioned factors are interrelated. For example, roller cone bits tend to walk to the right, which is related to the created side force at the bit. Figure 89 shows a schematic representation of forces acting on a BHA. (Baker Hughes INTEQ 1995)

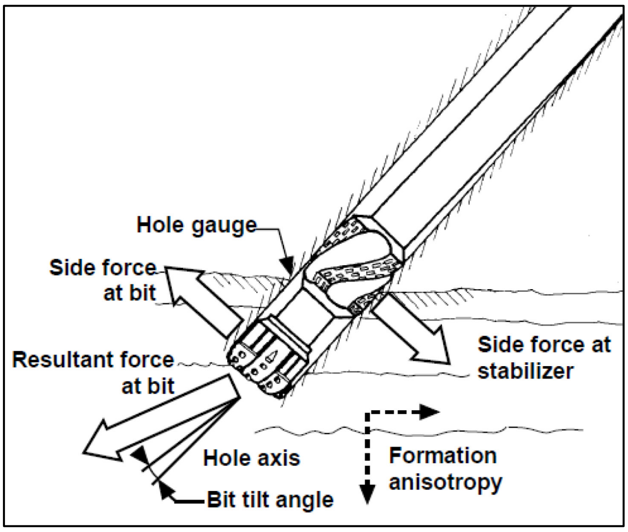

Figure 89: Forces acting on a drill bit[1]

There are three basic directional control principles (Baker Hughes INTEQ 1995):

- Fulcrum Principle (to build inclination)
- Stabilization Principle (to hold inclination and maintain the direction)
- Pendulum Principle (to drop inclination)

Please refer to Figure 90, Figure 91, and Figure 92 for a schematic representation of the three mentioned BHA types.

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[1] Baker Hughes INTEQ 1995. *Drilling Engineering Workbook: A Distributed Learning Course*. Houston, Texas: Baker Hughes INTEQ Training & Development.

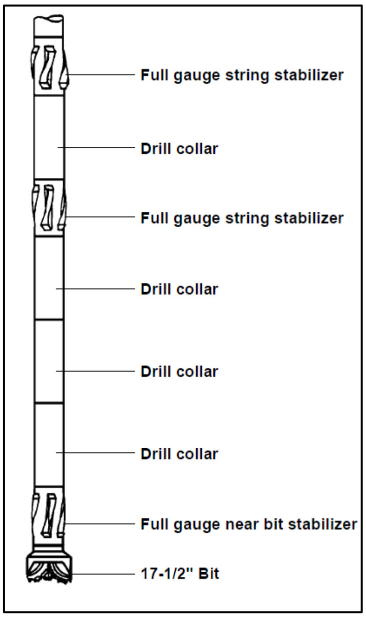

Figure 90: Schematic stabilizer placement of a fulcrum BHA[1]

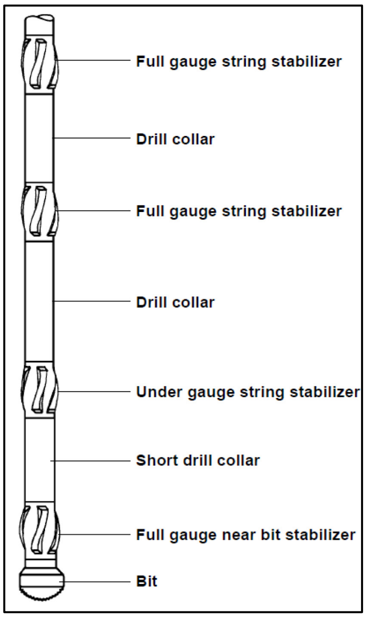

Figure 91: Schematic stabilizer placement of a stabilized BHA[1]

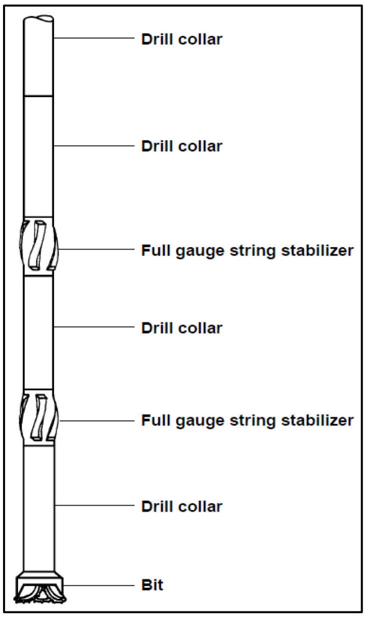

Figure 92: Schematic stabilizer placement of a pendulum BHA[1]

<u>Turbines</u>

Turbines are high speed and low torque power sections for the use in combination with PDC and impregnated bits.

Turbines consist of many stages (e.g., 150) where each stage consists of a rotor and stator connected to a shaft. Kinetic energy of drilling mud or water pumped through the turbine is transformed into rotational energy. Figure 94 shows the schematic setup of a typical turbine stage. The higher the number of stages, the higher the torque and horsepower output, but also the higher the pressure loss across the power section. A turbine consists of three main sections: the power section containing the turbine stages, a thrust- and radial support bearing, and a bent housing for directional applications (see Figure 93). The thrust-bearing performs the task to transfer the axial weight on bit towards the bit. (Lyons et al. 2016)

Figure 95 shows a turbine characteristic curve. A changing of flowrate changes the characteristic curve of the turbine. RPM and torque of a turbine are inversely proportional, meaning that an increase in RPM decreases the torque delivered to the drill bit. For a constant torque, the RPM is directly proportional to the flowrate. Runaway speed will be reached when the turbine is off bottom at zero torque, while maximum torque will be achieved on bottom, just at stall, when RPM is zero. Theoretical optimum performance is achieved at half runaway speed and half stall torque. (Baker Hughes INTEQ 1995)

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[1] Baker Hughes INTEQ 1995. *Drilling Engineering Workbook: A Distributed Learning Course*. Houston, Texas: Baker Hughes INTEQ Training & Development.

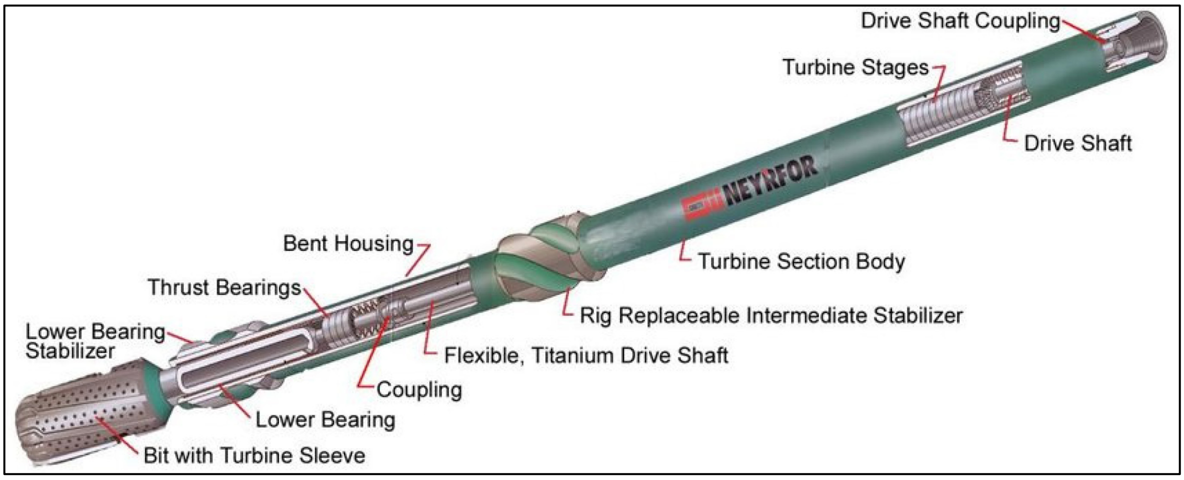

Figure 93: Downhole turbine design[1]

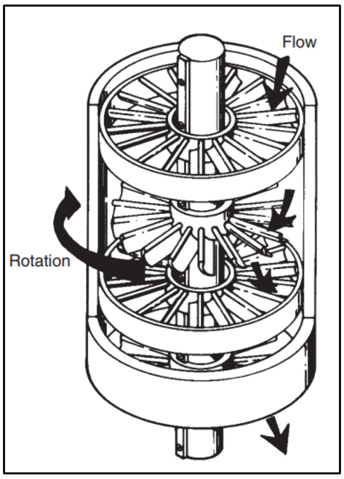

Figure 94: Single-stage of a turbine

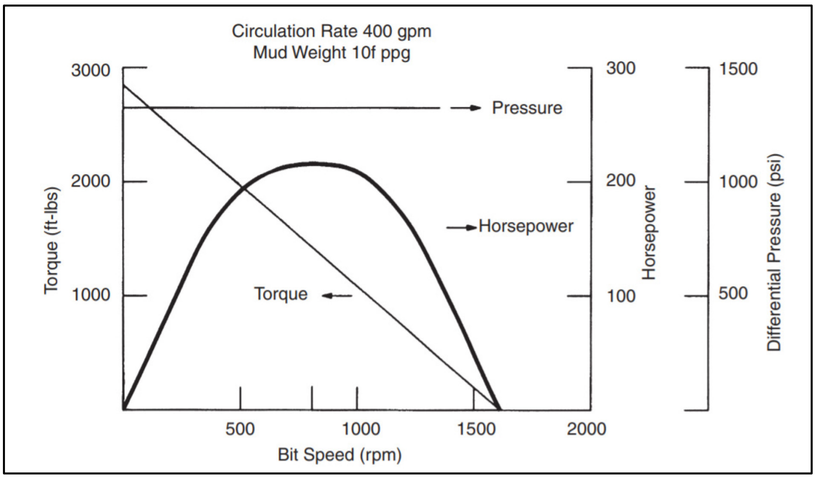

Figure 95: Turbine characteristic diagram (6.3/4” OD, 212 stages)

Few characteristic advantages and disadvantages of turbines could be obtained from the literature (Baker Hughes INTEQ 1995; Lyons et al. 2016):

Advantages	Disadvantages
• Ability to be used within hard to extremely hard rock formations when combined with impregnated bits.	• Low torque rating and high RPM limit the use with roller cone bits.
• Ability to achieve high ROP by high bit RPM.	• Very sensitive to particles within the mud (sand content must be kept at a minimum). LCM cannot be pumped through the turbine.

[1] Schlumberger. *Neyrfor Turbodrills*, https://www.slb.com/-/media/files/drilling/brochure/neyrfor-br.ashx (accessed 16 May 2020).

• No by-pass valve is required with turbines. Allows circulation regardless of motor action.	• Minimum surface indication (unless using MWD) if the turbine is stalling.
• Able to operate in high-temperature wells.	• High flowrates, accompanied by high-pressure drops across the turbine, require large surface pump systems.

Major advantage of turbines compared to PDM´s is their durability when used within harsh environments. However, turbines are rarely used (except in Russia) expensive tools, which often makes them not the first choice for hard rock drilling within Europe.

Positive Displacement Motor (PDM)

Positive displacement motors are hydraulically driven power sections applicable with almost any bit type.

PDM´s operate with a stator made of an elastomer and a helical rotor made of a rigid material like steel, covered with very hard chrome or tungsten carbide. Figure 98 shows a typical chamber of a PDM. Drilling fluid is pumped through the motor section allowing the hydraulic pressure to be transformed into torque. As the helical rotor rotates, the fluid passes from one chamber to the next, every chamber is a separate entity and as one closes to accept fluid from the preceding, the preceding closes (reverse Moineau principle). A PDM is made up of four main sections: the by-pass valve or dump sub which allows fluid to fill the drill string when tripping in, and fluid entering the drill string when tripping out, the motor section containing up to seven chambers, the bent house section and the bearing section with the drive sub (see Figure 96). (Lyons et al. 2016)

Speed and torque of a power section are directly linked to the number of lobes on the rotor and stator. The stator has one lobe more than the rotor, which leads to typical lobe cross-sections, as shown in Figure 97. (Mitchell 2006)

Figure 99 shows a characteristic operation diagram of a PDM. From the diagram, it can be obtained that a pressure of 100 psi needs to be overcome to start the motor (internal friction). The bit RPM will remain constant for a constant flowrate, while the torque and power output are directly linked to the pressure drop across the PDM. By increasing the WOB (when drilling hard formations with a roller cone bit), the resisting torque of the rock will increase, which will lead to an increased pressure drop across the PDM. If the PDM is lifted off bottom, the bit will rotate at constant RPM, while the pressure drop will decrease towards the value of internal friction (100 psi). The behavior of the PDM makes it possible to relate standpipe pressure to torque and power output at the PDM. (Lyons et al. 2016)

To perform directional drilling with a PDM with bent sub, the “tool face” needs to be correctly aligned before starting directional sliding. During sliding, the drill string remains without rotation, and only the bit is rotating powered by the downhole motor. Hole cleaning, high friction as well as differential sticking, are major challenges during sliding. Another challenging factor is the reactive torque, complicating accurate tool face orientation during sliding. The reactive torque is the anti-clockwise counteraction on the motor housing, created by the clockwise rotational action of the bit. Reactive torque typically increases when using very aggressive PDC bits or drilling with high WOB. (Baker Hughes INTEQ 1995)

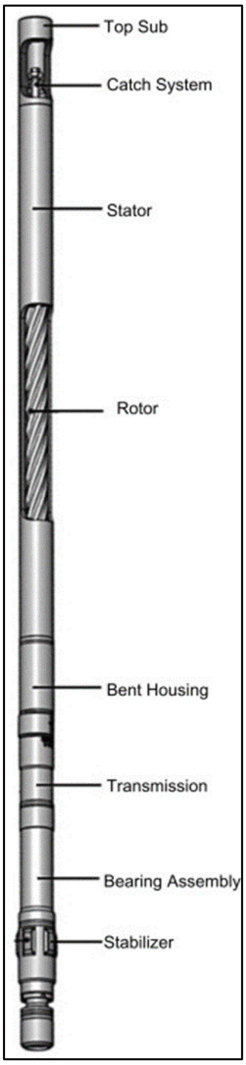

Figure 96: PDM design[1]

[1] Lyons et al. 2016. *Standard handbook of petroleum and natural gas engineering*, third edition. Waltham, MA: Gulf Professional Publishing.

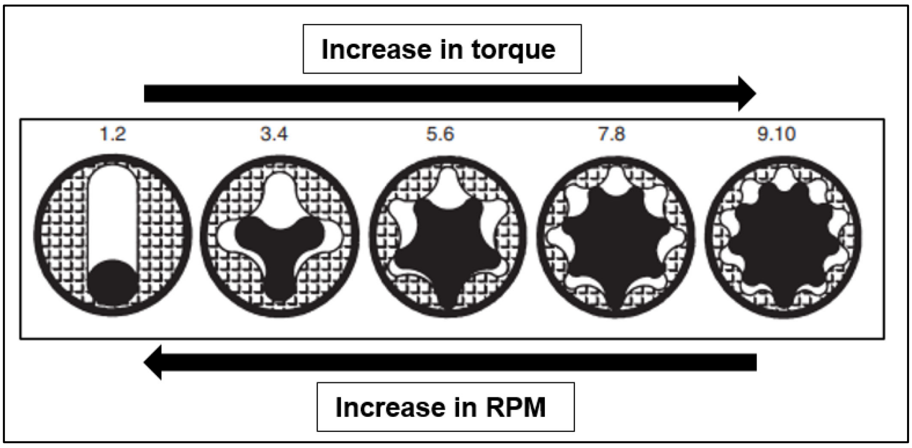

Figure 97: Lobe configuration and effect on torque and RPM output (modified after (Lyons et al. 2016))

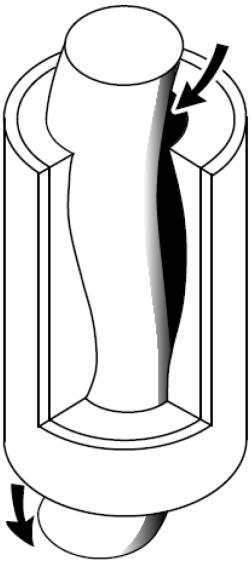

Figure 98: Single chamber of a PDM[1]

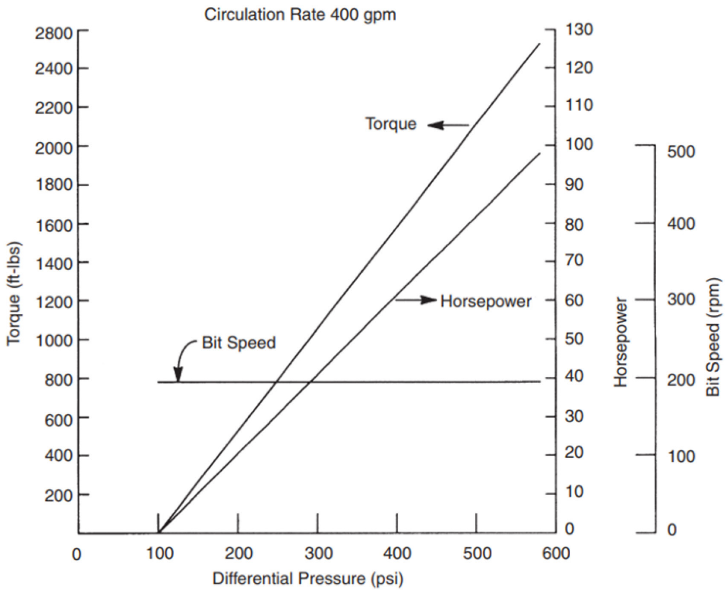

Figure 99: PDM characteristic diagram (6.3/4” OD, 5:6 lobe configuration)[2]

Few characteristic advantages and disadvantages of PDM´s could be obtained from the literature (Baker Hughes INTEQ 1995; Lyons et al. 2016):

Advantages	Disadvantages
• Ability to be used within any rock type in combination with almost any bit type.	• Stator elastomer is sensible to high temperatures.

[1] Baker Hughes INTEQ 1995. *Drilling Engineering Workbook: A Distributed Learning Course*. Houston, Texas: Baker Hughes INTEQ Training & Development.

[2] Lyons et al. 2016. *Standard handbook of petroleum and natural gas engineering*, third edition. Waltham, MA: Gulf Professional Publishing.

- Moderate pressures and flowrates required for operation. It can be operated with aerated muds and foam.
- Torque and power output are directly proportional to the pressure drop across the motor, while bit RPM is linked to the flowrate.
- High torque and low-speed configuration possible (high lobe setup), which is favorable for drilling with TCI or PDC bits within the crystalline basement.
- LCM can be pumped through the motor (manufacturer information needs to be followed).

- When the motor stalls, little to no fluid can be pumped through.

PDM´s are more common than turbines and, therefore, less expensive on the market. When it is intended to perform directional drilling in very hard and abrasive rocks. PDM with a bent sub in combination with a TCI or a special PDC bit might be a promising solution.

Rotary Steerable System (RSS)

RSS are state of the art directional drilling tools, which were invented to overcome the shortcomings of directional drilling by performing sliding actions. An excerpt from the Standard Handbook of Petroleum Engineering gives an excellent introduction to RSS.

> *“RSS allows continuous rotation of the drill string while steering the bit. This reduces drag, improves ROP, decreases the risk of sticking, and achieves superior hole cleaning.” (Lyons et al. 2016)*

Currently, there are two main RSS types on the market Push-the-bit systems (Figure 100) which use steering pads to push the bit into the desired direction, and point-the-bit systems (Figure 101) which points the bit into the desired direction, comparable to a bent-sub, but allowing continuous rotation. Steering commands are transferred to the downhole system via a downlinking. Downlinking is performed by flowrate adjustments of the surface mud pumps. (Griffiths 2009)

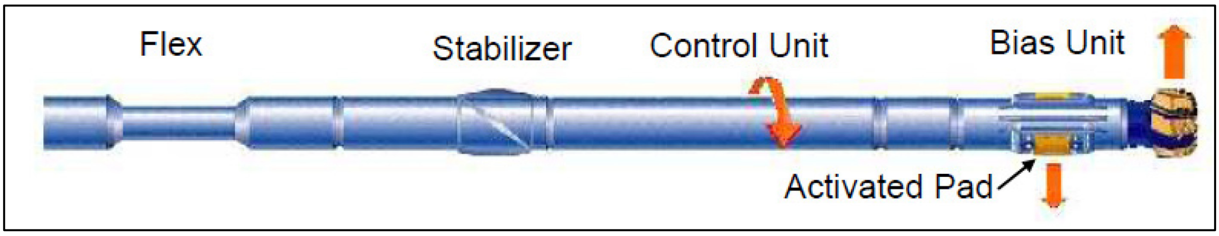

Figure 100: Push-the-bit RSS setup[1]

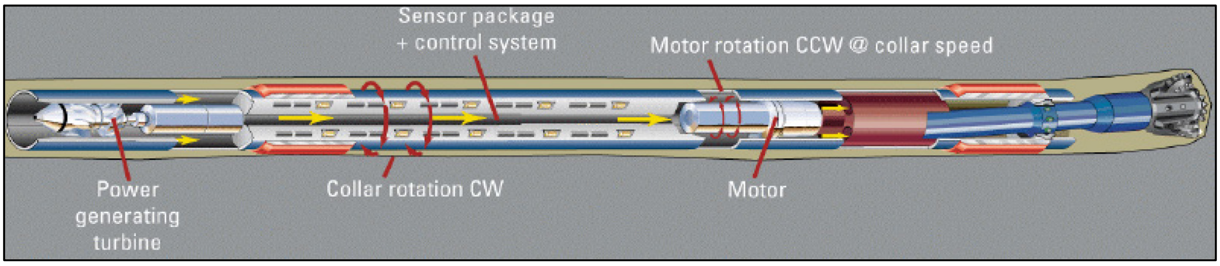

Figure 101: Point-the-bit RSS setup[2]

RSS can be operated as standalone or in combination with a downhole motor to increase bit RPM. Some service companies deliver an RSS with an integrated power section. Since RPM should be kept low, standalone systems or low-speed downhole motors are preferred for hard rock drilling. Furthermore, pads should be equipped with special hard facing to prevent premature erosion caused by abrasive formations.

Multi-Cycle Circulation Sub

Use of special downhole equipment such as PDM´s, turbines, MWD´s and RSS limits the maximum allowed pump rate (hole cleaning) and the use of LCM material (loss of circulation). Loss of circulation is a major concern when drilling within fractured crystalline basement. To bypass such BHA components, a multi-cycle circulation sub can be installed within the BHA. Different designs and operating principles are available on the market. However, the basic principle remains the same. Multi-cycle circulation subs allow multiple opening and closings of a flow path from the drill pipe to the annulus, bypassing sensible BHA components.

Drilling-on-Gauge (DOG) Sub

Drilling on gauge boreholes within extremely hard and abrasive formations presents a challenge. Drill bit gauge loss is a major concern when drilling within crystalline basement. Downhole tools such as the DOG sub are developed to maintain on gauge boreholes and to get feedback in case the bit loses its gauge.

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[1] Griffiths 2009. *Well placement fundamentals*. Sugar Land Tex.: Schlumberger.

[2] Griffiths 2009. *Well placement fundamentals*. Sugar Land Tex.: Schlumberger.

The Dictionary of Petroleum Exploration gives the following explanation:

> "***drilling-on-gauge sub*** *a sub with gauge inserts on the sides that is run above the bit or between the bit and downhole motor to ream the borehole*" (Hyne and Ormston 2014)

Figure 102: Drilling-on-gauge sub[1]

[1] Schlumberger 2012. *DOG Drilling on Gauge Sub*, https://www.slb.com/-/media/files/smith/product-sheets/dog-sub-ps.ashx (accessed 17 May 2020).

Appendix D - Engineering Charts Describing Minimum Gas Flowrates for Lifting Solids and Water

The engineering charts provided in this appendix give an overview of the required air injection rate for drilling vertical sections.

Following assumptions are made:

- Direct circulation method used
- Specific gravity of cuttings = 2.70 (water = 1)
- Average borehole roughness = 0.1 in.
- Minimum specific kinetic energy required for hole cleaning = 3 lb-ft
- Ambient pressure = 14.7 psia
- Ambient temperature = 60 °F
- Geothermal gradient = 0.01 °F/ft
- Relative air humidity = 0%

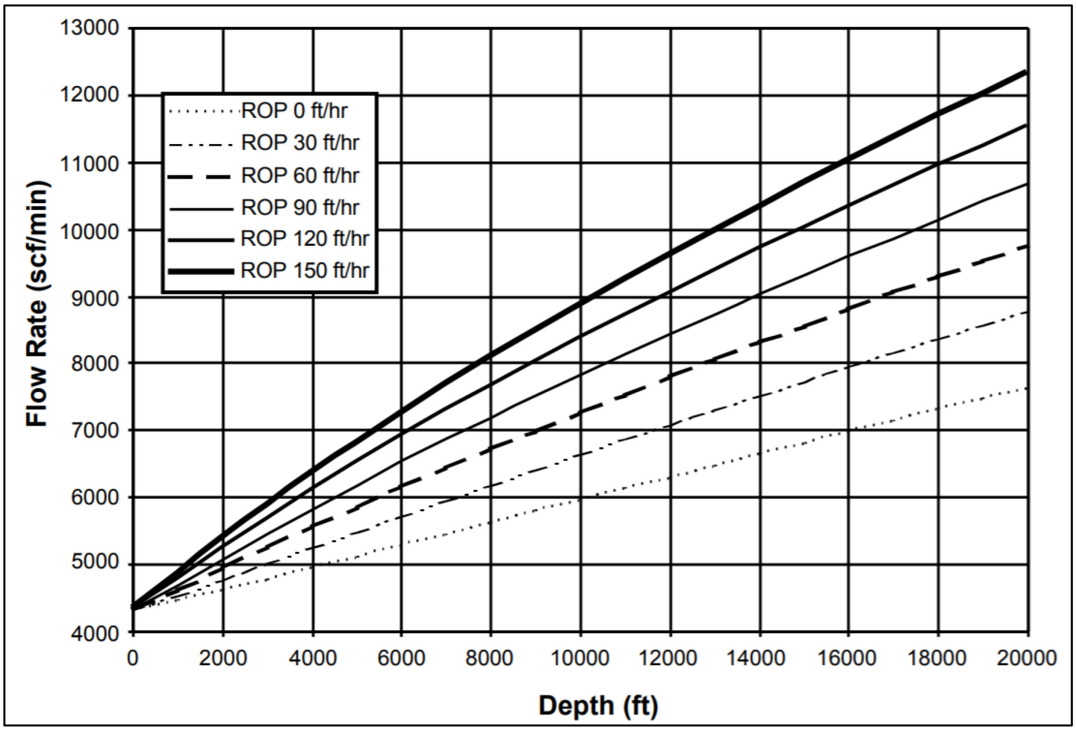

Figure 103: Required air flowrate for 17.1/2” borehole and 6.5/8” drill pipe[1]

[1] Guo and Ghalambor 2005. *Gas volume requirements for underbalanced drilling: Deviated holes*. Norwood Mass.

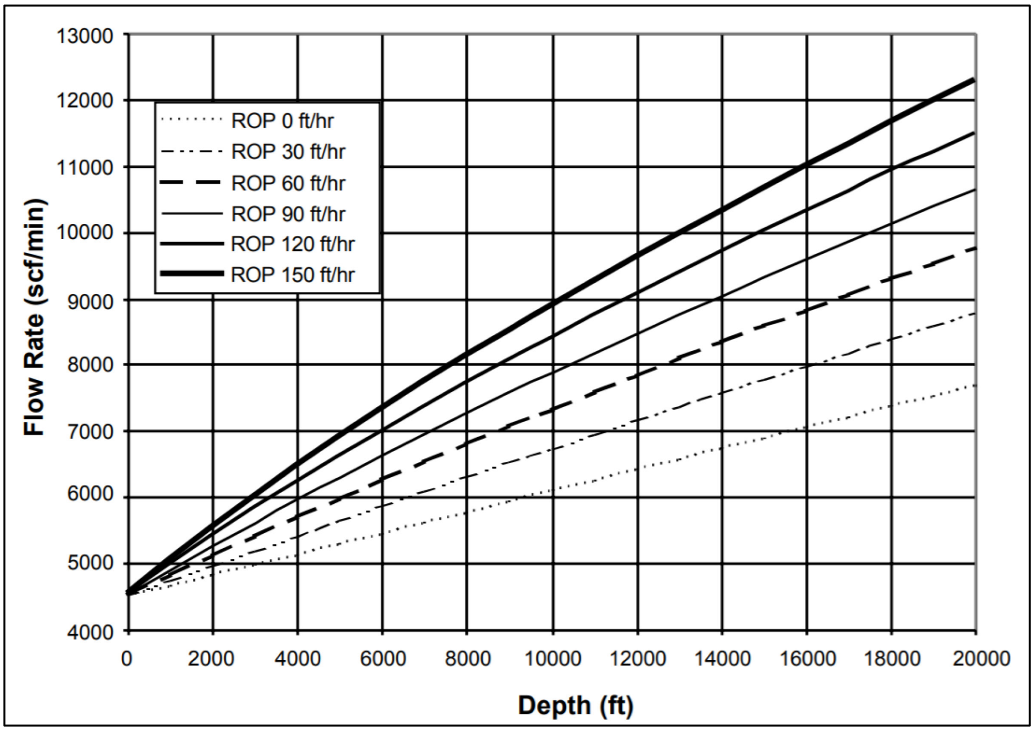

Figure 104: Required air flowrate for 17.1/2” borehole and 5.1/2” drill pipe[1]

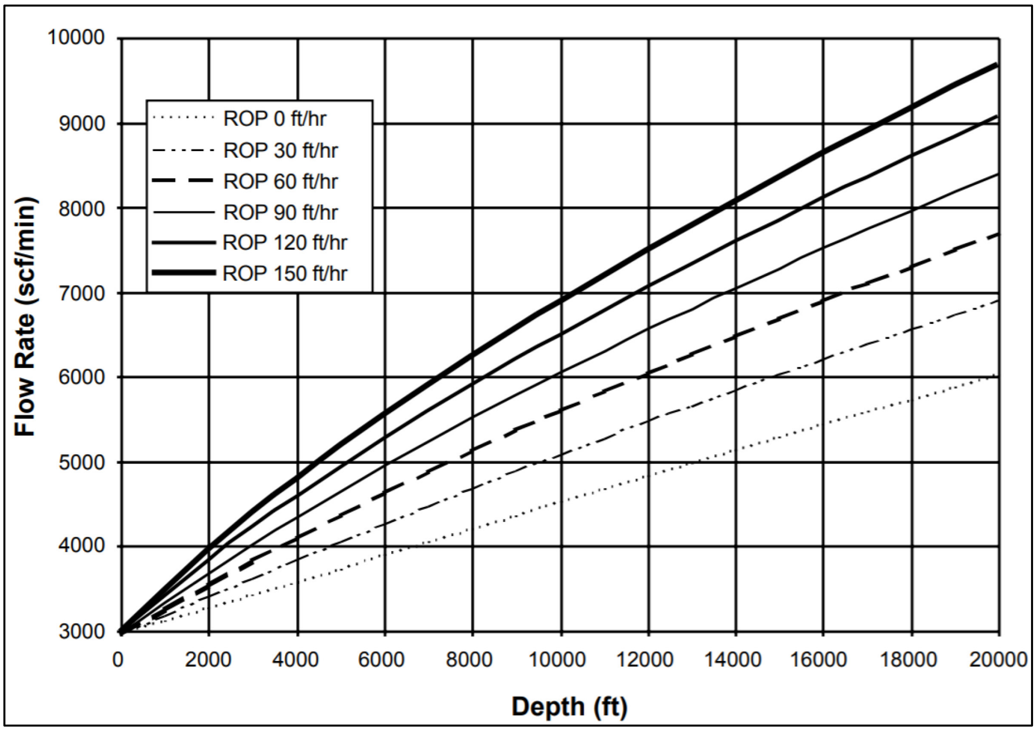

Figure 105. Required air flowrate for 15” borehole and 6.5/8” drill pipe[2]

[1,2] Guo and Ghalambor 2005. *Gas volume requirements for underbalanced drilling: Deviated holes*. Norwood Mass.

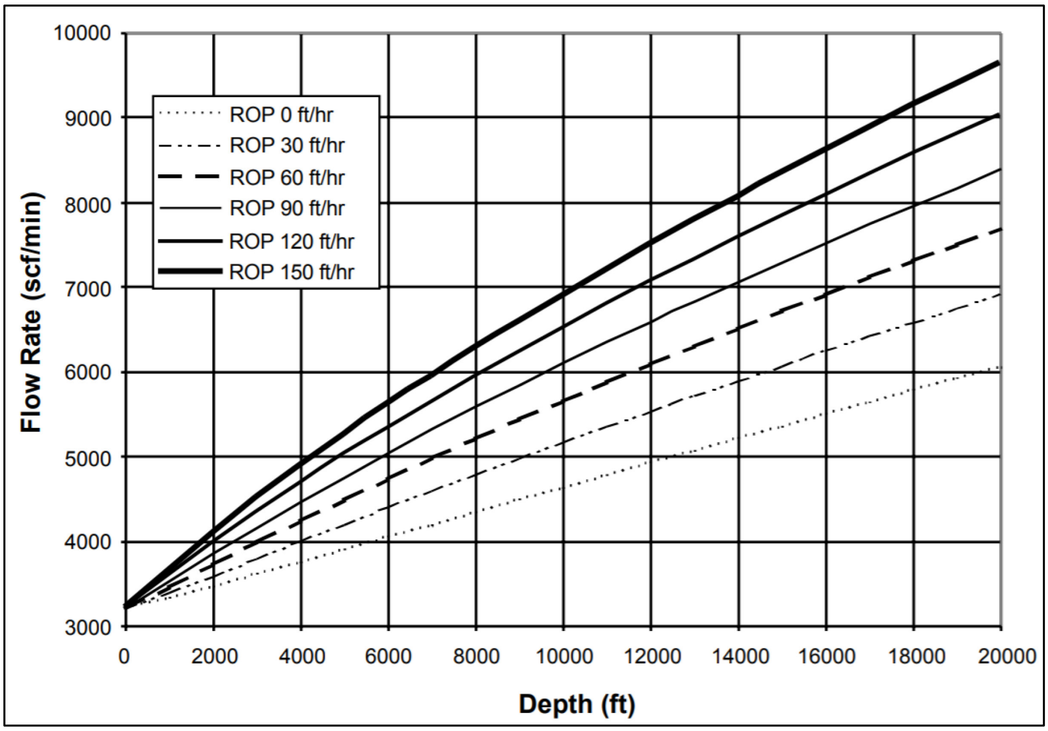

Figure 106: Required air flowrate for 15” borehole and 5.1/2” drill pipe[1]

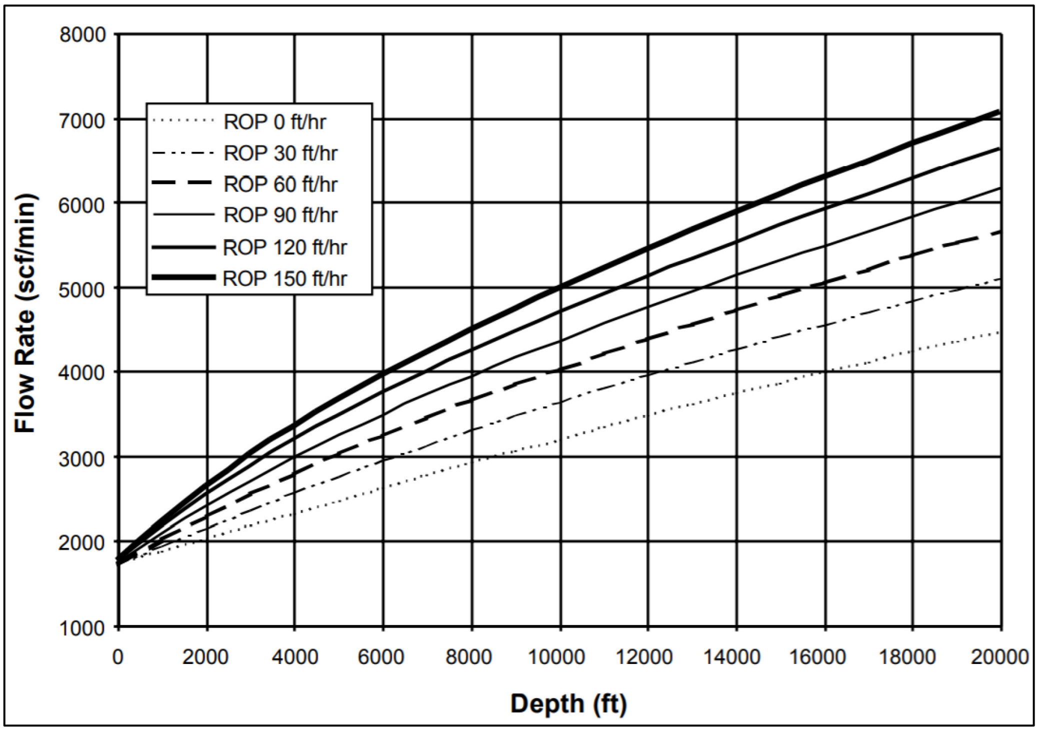

Figure 107: Required air flowrate for 12.1/4” borehole and 6.5/8” drill pipe[2]

[1,2] Guo and Ghalambor 2005. *Gas volume requirements for underbalanced drilling: Deviated holes*. Norwood Mass.

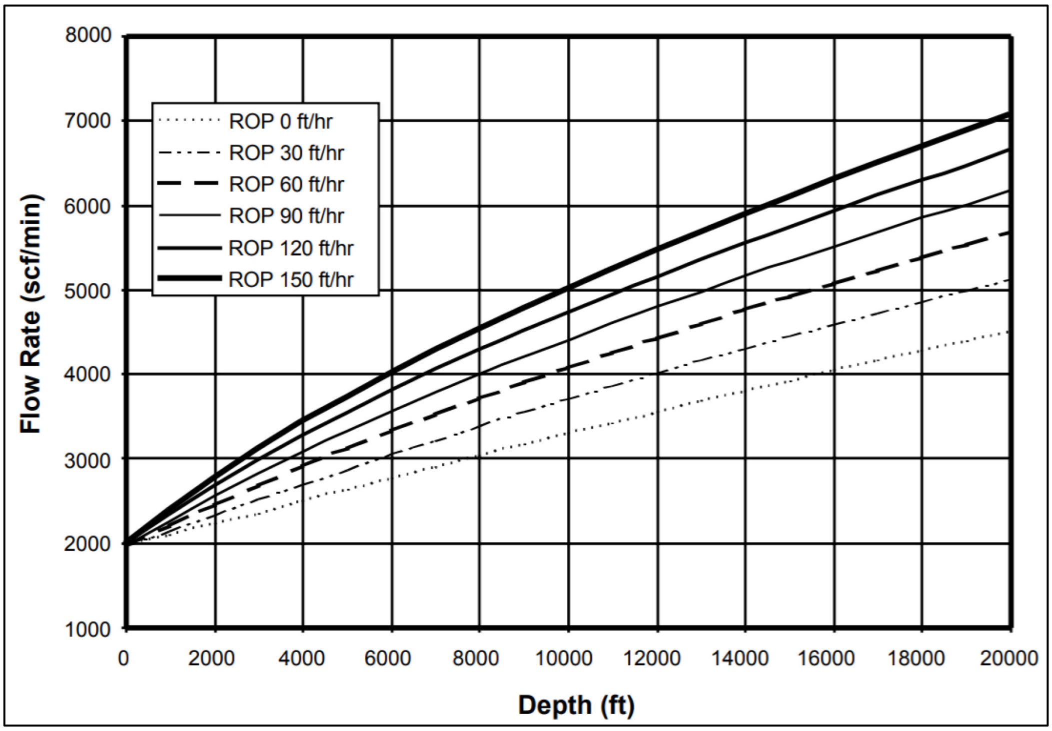

Figure 108: Required air flowrate for 12.1/4” borehole and 5.1/2” drill pipe[1]

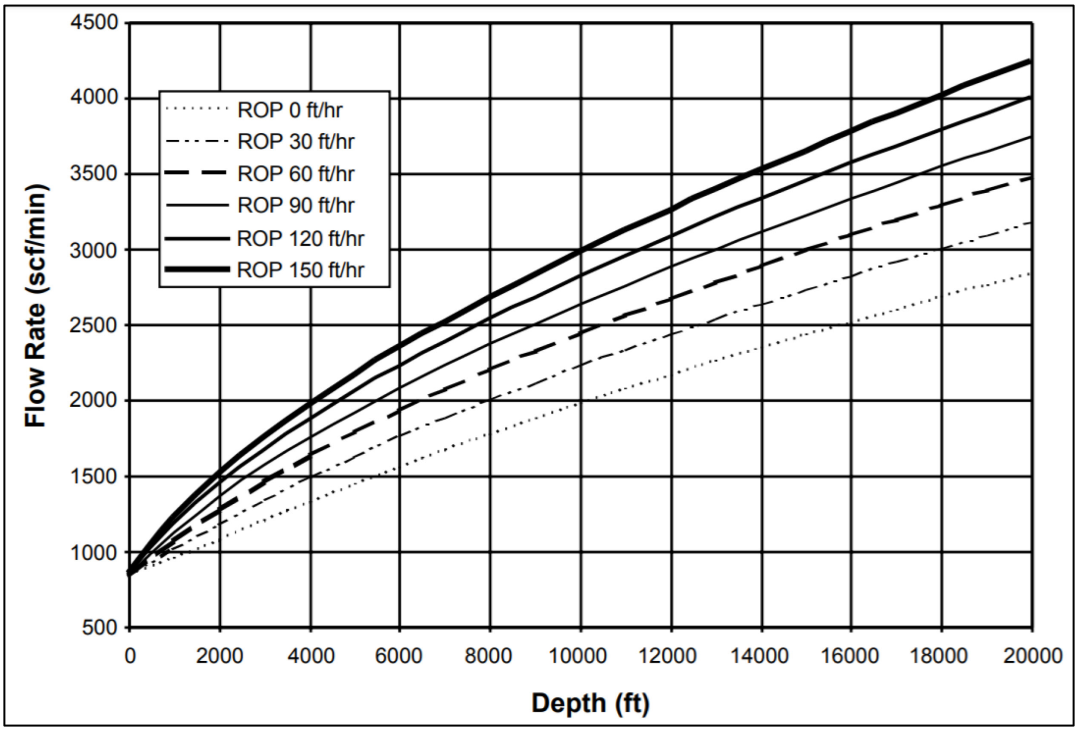

Figure 109: Required air flowrate for 8.3/4” borehole and 5” drill pipe[2]

[1,2] Guo and Ghalambor 2005. *Gas volume requirements for underbalanced drilling: Deviated holes*. Norwood Mass.

Appendix E – DTH Air Hammer Air Consumption Charts

This appendix provides an overview of air and pressure requirements for selected air hammer types in various sizes and from different manufacturers.

<u>Category above 20” nominal hole size</u>

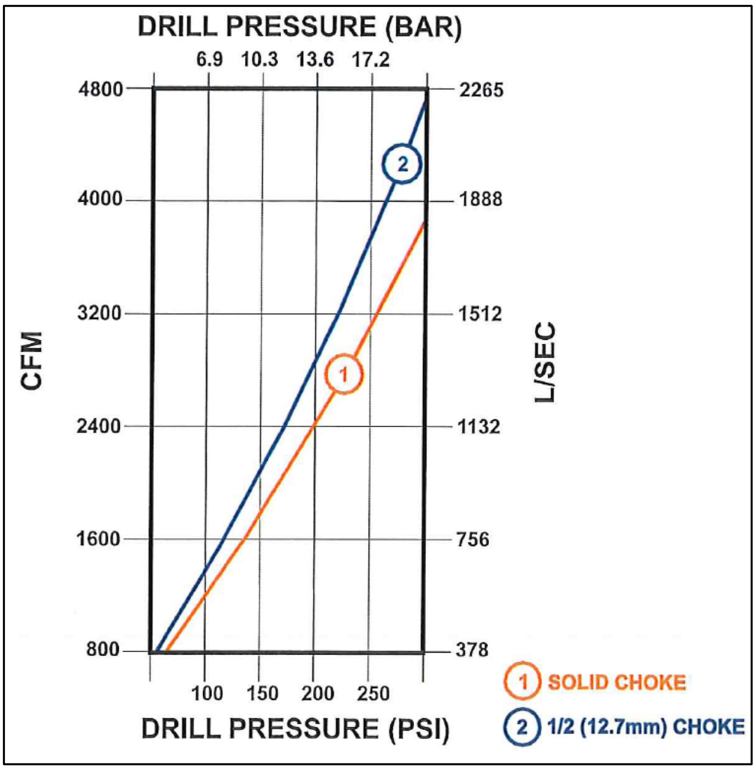

Figure 110: Numa Patriot 185 Air Hammer (Holes from 18” to 30”)[1]

[1] Numa 2020b. *Patriot 185 Down Hole Hammer Datasheet*, 2020.

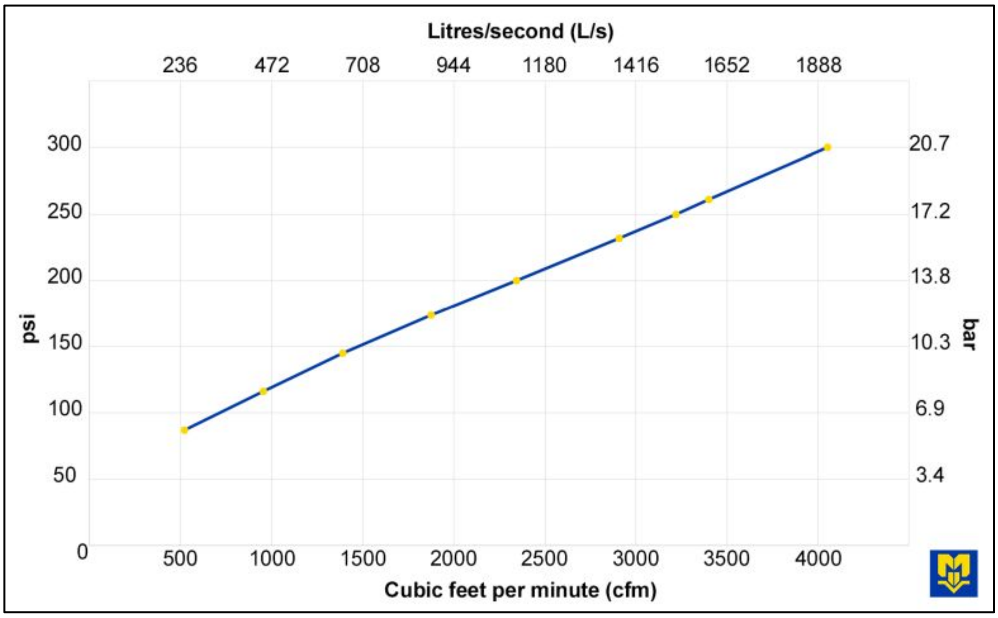

Figure 111: Mincon MP180N180 Air Hammer (Hole size min. 18”)[1]

Category 12.1/4” to 20” nominal hole size

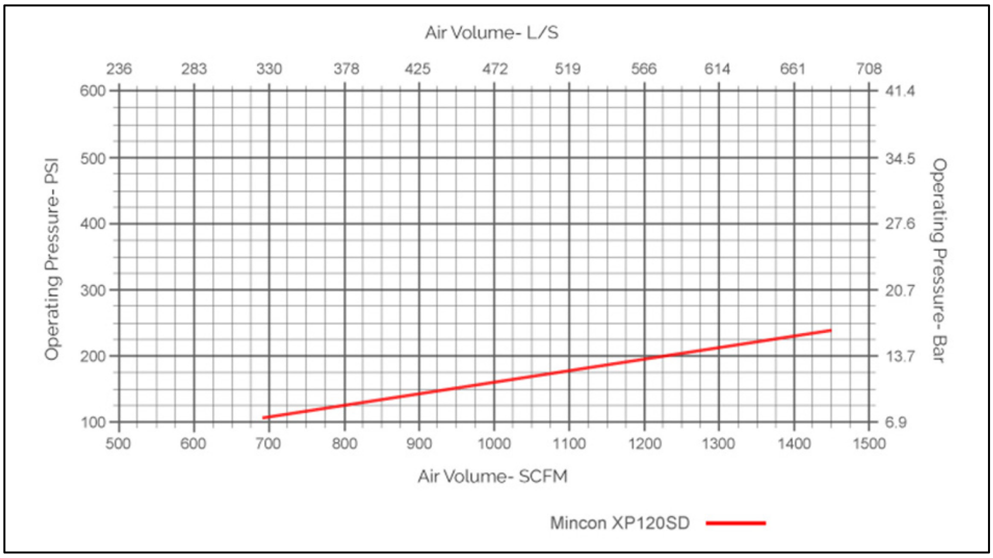

Figure 112: Mincon XP120QL Air Hammer (Hole size min. 12”)[2]

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[1] 2020. *Mincon MP180N180 Hammer - Mincon Group PLC: Air Consumption Chart*, 1 June 2020, https://www.mincon.com/products-popup/109-dth-hammers/18-dth-hammers/504-mincon-mp180n180-hamme.html#air-consumption (accessed 1 June 2020).

[2] 2020. *Mincon XP120QL Hammer - Mincon Group PLC*, 1 June 2020, https://www.mincon.com/products-popup/44-dth-hammers/12-dth-hammers/233-mincon-xp120ql-hammer.html#air-consumption (accessed 1 June 2020).

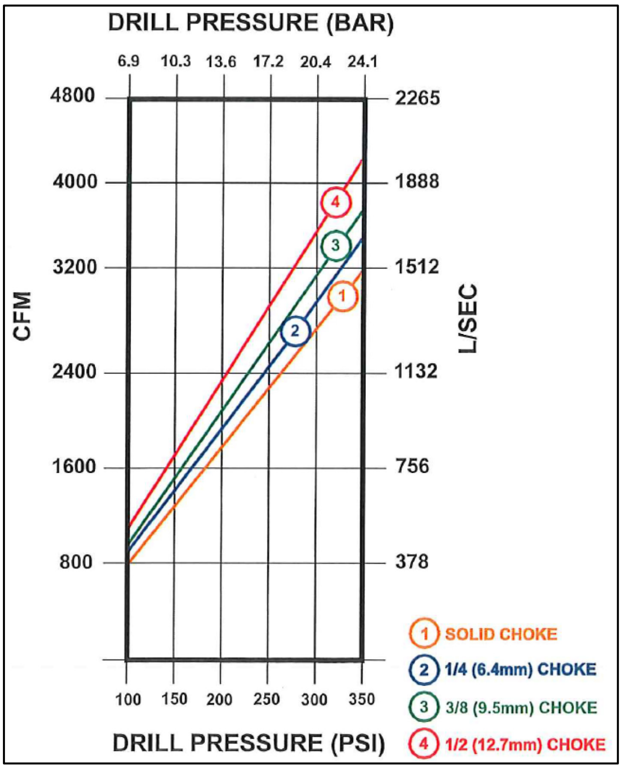

Figure 113: Numa Patriot 125 Air Hammer (Holes from 12.1/4" to 20")[1]

Category 6.1/8" to 12.1/4" nominal hole size

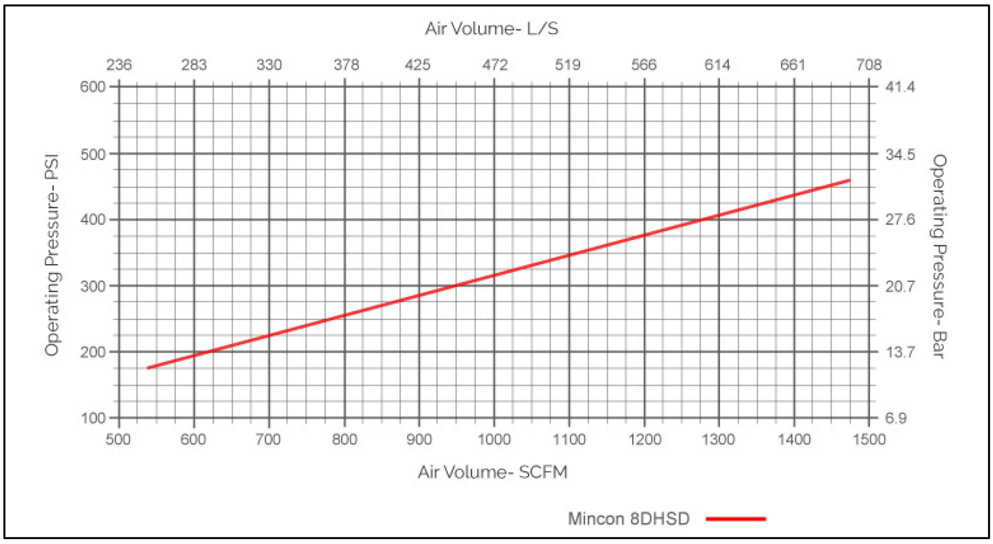

Figure 114: Mincon 8DHSD Air Hammer (Hole size min 8")[2]

[1] Numa 2020a. *Patriot 125 Down Hole Hammer Datasheet*, 2020.

[2] 2020. *Mincon 8DHSD Hammer - Mincon Group PLC*, 1 June 2020, https://www.mincon.com/products-popup/32-dth-hammers/8-dth-hammers/212-8-mincon-8dhsd-hammer.html#air-consumption (accessed 1 June 2020).

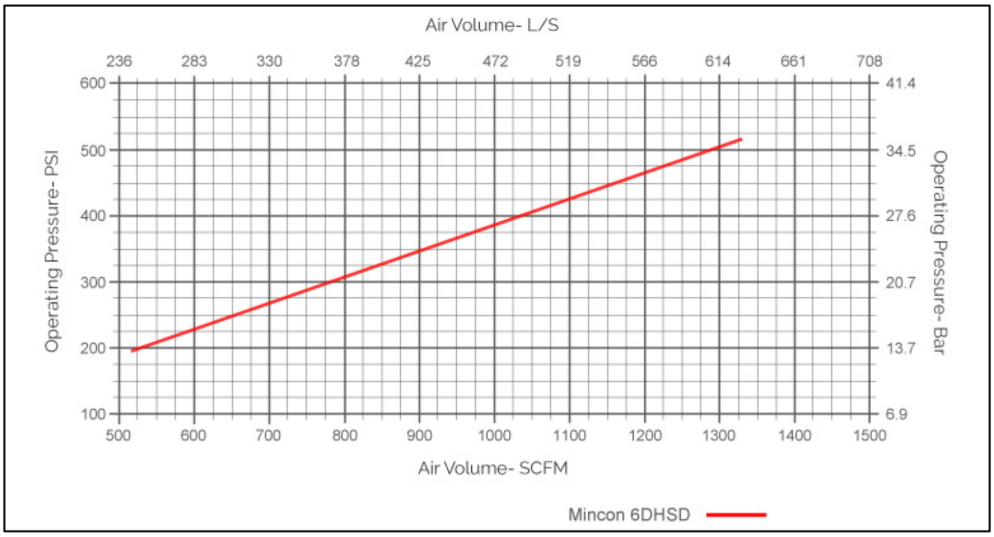

Figure 115: Mincon 6DHSD Air Hammer (Hole size min. 6")[1]

[1] 2020. *Mincon 6DHSD Hammer - Mincon Group PLC*, 1 June 2020, https://www.mincon.com/products-popup/31-dth-hammers/6-dth-hammers/202-6-mincon-6dhsd-hammer.html#air-consumption (accessed 1 June 2020).

Appendix F – Air Package Datasheets

Containerized Air Booster

B18TT-62-3000 – Diesel driven

General Information

	Metric	Imperial		Metric	Imperial
Dimensions	6.060 x 2.440 x 2.590 mm	20' x 8' x 8,6'	Inlet pressure	21 – 34 barg	300 - 500 PSIG
Weight	14 000 kg	30 850 LBS	Outlet temperature	A +40 °C	A +72 °F
Noise level LWA (with extra containers)	116 dB(A) (110 dB(A))		Outlet temperature with extra cooling container	A +15 °C	A +27 °F
Power	563 kW	755 hp	Container approval	DNV 2.7-1	
Fuel consumption (full load)	145 l/hr	38ga/hr	Area classification	Safe area use	
Internal diesel tank	550 lt	145 ga	Inlet connection Outlet connection	ANSI: 4" 300 LBS ANSI: 3" 1500 LBS	
Operating temperature range	-20°C / +45°C	-4°F / 113°F	Safety valves	Fitted on inlet & outlet	

Capacity chart

	Inlet pressure		Outlet pressure				Free air delivery			
			Single stage		Two stage		Single stage		Two stage	
	barg	PSIG	barg	PSIG	barg	PSIG	m³/min	CFM	m³/min	CFM
Tier 2	34	500	100	1450	207	3000	127	4500	91	3200
Tier 2	24	350	69	1000	145	2100	90	3170	64	2250
Tier 4f	34	500	100	1450	207	3000	121	4250	86	3000
Tier 4f	24	350	69	1000	145	2100	85	3000	61	2100

Cat-class: 430-1120 & 430-1130 Version: Europe – January 2019

Figure 116: Containerized B18TT-62-3000 Booster[1]

[1] Copco 2020. *High Pressure Air & Nitrogen Boosters - Atlas Copco Österreich*, 25 June 2020, https://www.atlascopco.com/de-at/Rental/products/air-rental/booster-compressors/AirNitrogenbooster (accessed 25 June 2020).

Y35 Stage IV

Oil-injected air compressor - diesel driven - Stage IV

General Information

Dimensions (l x b x h)	m	5x2.3x2.6 (wagon towbar up)	Ambient temperature	°C	-25/+45
Weight	kg	7690	Internal fueltank	l	750
Sound Pressure at 7m	db(A)	72	Internal AdBlue tank	l	70
Air outlet temperature	°C	A+15	Typical oil content	mg/m³	<3
Air outlet connection		2"			

Performance			Engine		
Pressure range	bar(g)	15-35	Type	Scania DC16 V8	
Nominal pressure	bar(g)	35	Output	kW	478
Max. capacity	m³/min	39,8 @25bar; 35,4@35bar	Fuel consumption (100% load)	l/h	94,5
			Max. AdBlue consumption	l/h	6,6

Main features

Spillage free frame	Spark arrestor
Integrated aftercooler with bypass	Inlet shutdown
External fueltank connection	CE certified

Figure 117: Drill Air Y 35 Stage IV Compressor Datasheet[1]

[1] Copco 2020. *DrillAir Y 35 - Atlas Copco Österreich*, 25 June 2020, https://www.atlascopco.com/de-at/rental/products/air-rental/oil-injected-air-compressors-for-rent/diesel-driven/drillairy35 (accessed 25 June 2020).