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POTENTIALS FOR COST REDUCTION FOR GEOTHERMAL WELL CONSTRUCTION IN VIEW OF VARIOUS DRILLING TECHNOLOGIES AND AUTOMATION OPPORTUNITIES

Erlend Randeberg[i,a], Eric Ford[i], Gerhard Nygaard[i], Magnus Eriksson[ii], Leif Jarle Gressgård[i], Kåre Hansen[i]

[i)]IRIS – International Research Institute of Stavanger
P.O. Box 8046, N-4068 Stavanger, Norway

[ii)]SINTEF Materials and chemistry
R. Birkelandsvei 2, N-7465 Trondheim, Norway

[a)]Corresponding author: erlend.randeberg@iris.no

ABSTRACT

Drilling cost is a bottleneck for commercial development of most unconventional geothermal energy projects. Direct transfer of technologies and experience from drilling of oil and gas wells generally involves costs that may be unbearable when developing cost-effective geothermal energy projects.

A discussion of necessary means for reducing costs when drilling geothermal wells is presented in this paper. In recent years, several new drilling concepts have been suggested, such as tools for more efficient hard rock drilling. In addition, possibilities of implementing off-the-shelf automation technologies used in various other industries, such as supervisory control, are emphasized. Requirements for "fit-for-purpose" sensor systems, automated procedures, as well as existing automation equipment developed for drilling of oil and gas wells are investigated in terms of reduced crew costs, reliability and risk.

Possible replacement of drilling crew members by utilizing "state-of-the-art" automation technologies raises questions as to how the drilling crew organization may be re-structured. Relevant aspects on drilling crew re-organization and reluctance towards changes are discussed.

Furthermore, it is considered essential to understand the entire drilling operation, in terms of pinpointing cost elements and duration of the phases involved. Implementation of tools for probabilistic well cost estimation is discussed as a way forward.

Implementation of discussed technologies and methodologies for geothermal drilling and well development may also prove valuable for oil and gas industry, thus ensuring competence transfer in the opposite direction of what has historically been the case.

INTRODUCTION

The costs of constructing wells are challenging for the geothermal energy industry, especially when deep and complex wells are required for sufficient heat extraction. The potential for major penetration of geothermal energy into the general energy market relies on significant reduction of well construction costs.

Construction of deep boreholes is associated with expensive and time-consuming operations, with the drilling process being the major constituent. Drilling typically accounts for more than half of total geothermal power plant costs, and the costs for drilling operations involving existing drilling equipment and automation level, typically increase nonlinearly with depth (e.g. Tester *et al*., 2006; Augustine *et al*., 2006; Teodoriu & Cheuffa, 2011). This suggests that reduced geothermal energy costs rely heavily on more cost-effective drilling.

On the other hand, the question of how the well construction costs can be reduced may be addressed by investigating the cost drivers. Generally speaking, well construction technologies and methods are developed for the petroleum industry. Building up this expertise has allowed the development of deep and complex wells. However, it may prove very challenging to transfer technology and practices from the petroleum to the geothermal industry especially due to the cost.

The petroleum industry's potential for large profits, combined with high standard safety solutions, have contributed to a secondary focus on well construction costs. For the geothermal industry – conventionally more or less adopting solutions from the petroleum industry – high well construction costs make the extraction of geothermal heat unattractive in many cases. In addition to the cost of the drilling rig, crew etc., it is worth considering that geothermal well

construction often involves hard rock drilling, very deep wells (especially in the case of Enhanced Geothermal Systems – EGS), and requirements for equipment withstanding high temperatures. However, as petroleum wells are drilled deeper, the reserves are more difficult to attain, and more complex well construction is required, the cost issue is rising on the agenda even for the oil and gas industries. The relation between geothermal and petroleum drilling – and its synergies – is therefore an important aspect for both industries.

Technology transfer between the petroleum and the geothermal industry has been discussed by e.g. Falcone & Teodoriu (2008) and Petty *et al*. (2009). Challenges of geothermal exploitation around the world are elaborated, focusing specifically on those aspects that overlap with the oil and gas expertise. Examples are drilling and completions practices, characterization of fluid flow through porous media and in wellbores, as well as reservoir fracturing issues. It should be emphasized that drilling rigs, casing, tools, and other oil field services are also used for drilling geothermal wells, illustrating the synergies especially between EGS and petroleum drilling. Technology transfer between these energy sectors is considered very potent.

To enable the highest energy efficiency of the EGS, these wells need to be drilled deeper than conventional geothermal wells and very often in hard rock formations. To achieve a sufficient cost reduction for these hard rock operations, new technologies originating from other areas than oil and gas can also play an important role. In this respect there might be a significant potential for technology transfer from drilling tools, materials, procedures and systems developed within the area of mining and construction; such as blast holes for mining, water wells and geology operations, as well as large and small scale tunnelling and continuous mining operations.

In general, the geothermal industry's need for reduced well construction costs should be addressed through discussion of several possible solutions. Therefore, key technological issues, as well as means for systematizing the complex well construction process, will be discussed in the following. The approach of multiple focus areas may be increasingly valuable as EGS is developed further, as stated by Polsky *et al*. (2008).

Significant reductions in well construction costs depend upon a number of factors, and this paper includes a discussion of some of the means available. The approach is based on the authors' experience from the field of petroleum well construction, allowing a relatively broad approach.

The structure of the paper is the following. First, geothermal well construction is reviewed with regards to its relation to petroleum well construction and investigations of well cost. Second, means for improved performance and reduced cost through tools for well cost estimation, new drilling technologies and automation opportunities are discussed. A case study showing possible improvements in well construction cost-effectiveness is given for a petroleum well. Finally, a discussion of possible improvements and implications is given as well as some concluding remarks.

REVIEW OF GEOTHERMAL WELL CONSTRUCTION

Construction of a geothermal well is a complex process and the area of geothermal well construction and different means for reducing its costs are being approached by a number of research communities. This section includes a literature review of geothermal well construction with special emphasis on energy cost, decision-support, well cost modelling tools and some relevant research initiatives focusing on building up competence.

The European research network *ENGINE*[1] is one of the key initiatives. The main objective is coordination of research and development initiatives for unconventional geothermal resources and in particular EGS, ranging from the resource investigation and assessment stage through to exploitation monitoring (e.g. Ledru *et al*., 2006). ENGINE gathered 35 partners from 16 European and 3 non-European countries including 8 private companies from 2005 to 2008. One outcome of the network was a techno-economic performance tool for EGS (described in the following subsection).

The *GEBO* technology transfer program aims at improving the economics of geothermal energy recovery from deep geological strata by investigating new concepts and basic scientific work (Reinicke *et al*., 2010). Based in Lower Saxony (Germany), more than 40 scientists and engineers work together with industry to develop and evaluate new concepts, materials and devices. Among the key areas are decreasing deep drilling costs, development of reliable drilling technology at temperatures above 200°C and improvements within hard rock drilling.

[1] ENhanced Geothermal Innovative Network for Europe (the ENGINE Co-ordination Action). http://engine.brgm.fr/

Relevant US EGS efforts are described e.g. by Polsky *et al*. (2008). An evaluation of well construction technology is given, assessing the ability of existing technologies to develop EGS wells, and identifying research areas and technologies critical for cost-effective well construction. Cost estimates for case studies are based on the WellCost Lite model.

Tools for Geothermal Energy Cost Estimation

This section deals with some existing tools and initiatives for the estimation of geothermal energy cost and improving energy cost effectiveness. The existing tools and models for analysis of geothermal energy cost are generally developed for decision support. Generally speaking, when the total geothermal energy cost is addressed, some cost model for the well construction part is implied. Such cost models are treated in the following subsection.

A principle approach to energy cost estimation is suggested by Barbier (2002), considering the phases of a geothermal project development as illustrated in Figure 1.

Tools and analysis of geothermal energy cost are generally relatively simple models, and typically spreadsheet-based.

The ENGINE project delivered a tool for Performance Assessment (*ENGINE PA*) and a Decision Support System (*ENGINE DSS*). As described by van Wees *et al*. (2008), the approach is based on four aspects of the techno-economic chain of geothermal energy projects for calculating the performance:

1. Basin properties
2. Underground development (well)
3. Surface development (topside)
4. Economics

The model is a full-field production/cash flow model, based on flow in natural or stimulated fractures. When including economic figures on capital expenses, operating expenses and energy prices, the economic performance and uncertainties can be evaluated.

The cost of well development in ENGINE is only treated in terms of a simple expression depending on length of the borehole and a scaling factor (user inputs in the spreadsheet).

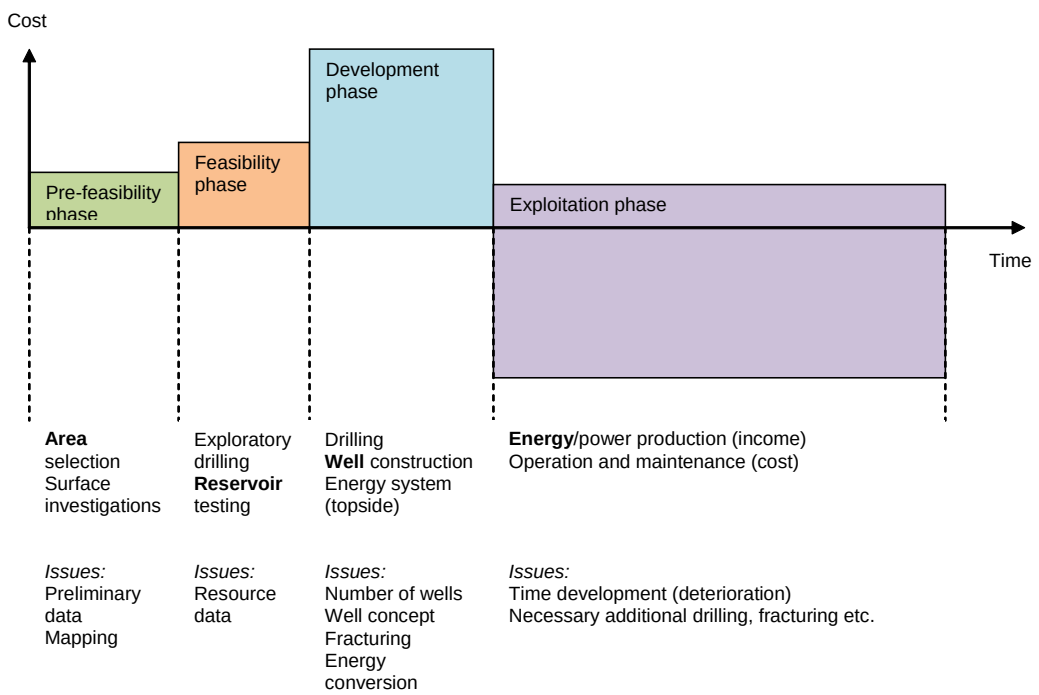

Figure 1 Phases, issues and cost of a geothermal project, as structured by Barbier (2002)

The *GETEM* (Geothermal Electric Technology Evaluation Model) is another techno-economic systems analysis tool for evaluating and comparing geothermal project cases (Entingh *et al*., 2006; Mines, 2008; Young *et al*., 2010). Both EGS and hydrothermal geothermal projects are included in the analysis, aiming at estimating cost of geothermal electricity.

Cost calculations in GETEM are broken down into five sections:

1. Resource definition and confirmation
2. Well-field construction
3. Reservoir management
4. Conversion system
5. Economics

Well costs are determined through selecting a well cost curve, the depth of the wells, a user cost multiplier, surface equipment cost per well, the success rate of exploration drilling, the number of confirmation wells required, the success rate of confirmation drilling, ratio of injection to production wells, and the number of spare production wells. Well costs are not calculated from the detailed factors that govern well costs; it uses available information of cost as a function of depth. Because GETEM does not calculate well costs from governing factors, but instead uses generic well costs, the model includes a cost multiplier that allows the user to adjust generic costs to those applicable to a specific project. This is being done by using another model – WellCost Lite (see next subsection).

The *HDRec* (Hot Dry Rock economic) software is a cost-benefit analysis program for geothermal projects that combines economic aspects with the technical characteristics of the surface installations and the hydro-geological and thermal properties of the subsurface. The cost of boreholes is one of many input parameters. The software was developed in relation to the Soultz-sous-Forêts (France) EGS project (Heidinger *et al*., 2006).

The *MIT EGS* model, also referred to as "EGS Modeling for Windows", is a tool for economic analysis of enhanced geothermal systems. The model has been updated using the results of several previous studies with regard to the cost of drilling, plant costs, stimulation costs, and the learning-curve analysis (Tester *et al*., 2006).

Sanyal (2010) suggests steps that can be taken towards minimizing the levelized cost of electric power from EGS. Numerical simulations of the economic performance using a number of uncertain variables, including cost of drilling, are done based on a drilling cost versus depth correlation.

Generally speaking, the cost of constructing geothermal wells is considered as direct input or based on simple functions of depth in the energy cost models described above. As the well cost depends on a large number of parameters, there is clearly a need for more comprehensive investigations on the well construction cost itself. The following section reviews available well construction cost models.

Geothermal Well Construction Cost

Treating the well construction cost as a "black box" clearly simplifies the challenge of supplying decision support on investments in geothermal energy projects. However, being the major cost element in most geothermal plants, it is essential to assess the well construction costs in a somewhat greater level of detail.

Geothermal well cost estimates are often based on relatively simple cost per depth inputs or historical data. Entingh *et al*. (2006) put it this way:
"In the past, people have tried to estimate geothermal drilling costs by multiplying oil & gas costs by a scaling factor. That does not work. A second lesson is that geothermal well costing must be done in context. That is, one can not meaningfully discuss geothermal well costs without establishing the context including the location, the design, problems to be encountered, etc. A third lesson is that the well design and technology employed are very important."

Cases showing cost of well construction are fewer for the geothermal than for the petroleum industry. However, comparison of the two, including an indication of development over time, can be done, as shown in Figure 2.

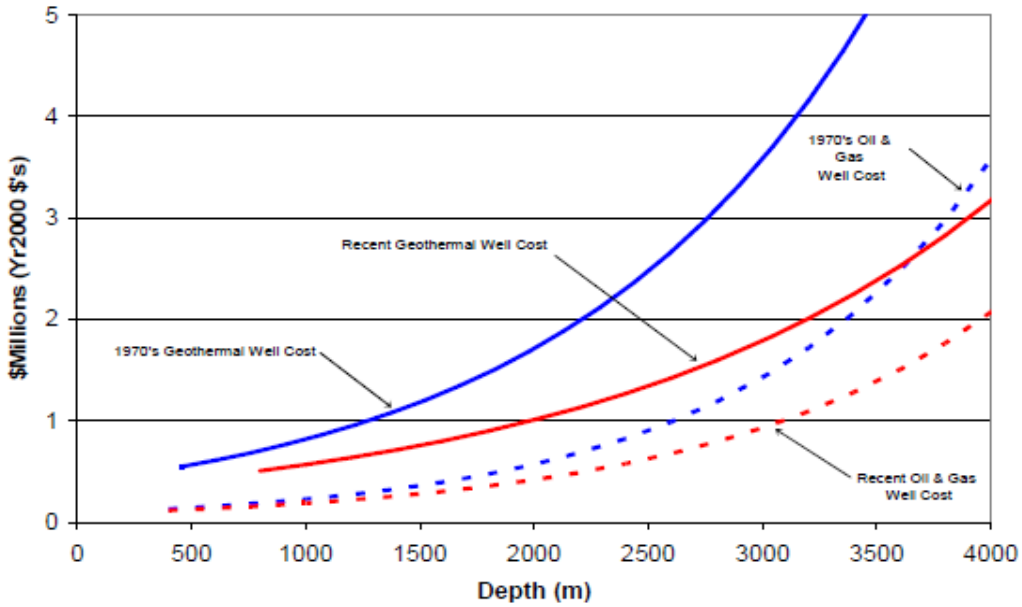

Figure 2 Cost trends for oil & gas and geothermal wells in year 2000 dollars (Mansure et al.*, 2005)*

As pointed out e.g. by Tester *et al*. (2006), an apparent challenge is that there is insufficient detailed cost history of geothermal well drilling to develop a statistically based cost estimate for predicting well costs where parametric variations are needed. Therefore, correlations giving a general estimate of drilling costs based on depth can hardly explain what drives the costs allowing one to make a well-specific estimate.

The *WellCost Lite* model (Mansure *et al*., 2005; Augustine *et al*., 2006) was developed for estimation of well costs based on a wide array of factors. Figure 3 shows completed well costs as a function of depth for oil and gas wells and hydrothermal and EGS geothermal wells. In addition, predicted costs based on the WellCost Lite model are shown. The principles of flow of information in the model are given in Figure 4, indicating the approach taken.

The model is spreadsheet based and allows the input of a casing design program, rate of penetration, bit life and trouble map for each casing interval. The time to drill each interval is calculated, including rotating time, trip time, mud and related costs and end of interval costs such as casing and cementing and well evaluation. Also, the cost for materials and time required to complete each interval is calculated. The calculated time is multiplied by the hourly cost for all rig time related cost elements such as tool rentals, blow out preventers (BOP), supervision etc. The total cost is obtained by summing all intervals. The cost of the well is displayed as both a descriptive breakdown and on the typical authorization for funds expenditure (AFE) form commonly used to estimate drilling costs.

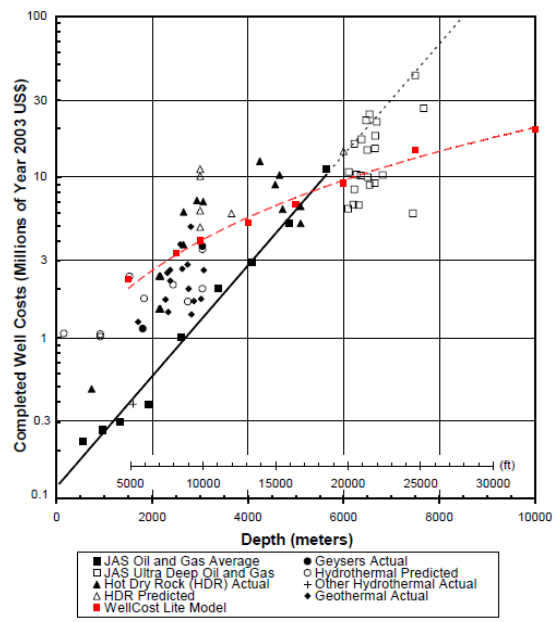

Figure 3 Completed well costs as a function of depth in year 2003 US$, including estimated costs from WellCost Lite Model (red curve). See Augustine et al. *(2006) for details.*

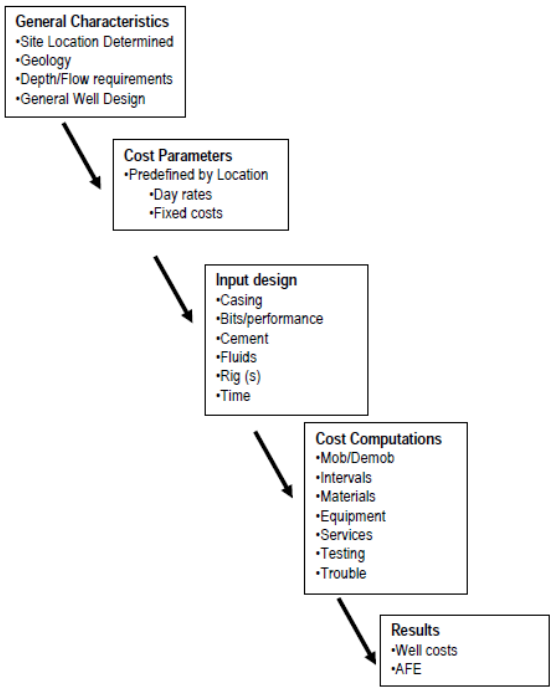

Figure 4 Flow of information in WellCost Lite from general Characteristics to resultant well cost, as presented by Entingh et al. *(2006).*

The WellCost Lite model's cost elements can be structured into five categories:

1. Pre-spud costs
2. Casing and cementing
3. Drilling – rotating costs
4. Drilling – non-rotating costs
5. Trouble costs

Mansure *et al*. (2005) indicate that the cost of drilling geothermal wells can be divided in three almost equal parts:

1. Rock reduction and removal
2. Permanent well stabilization (casing)
3. Other

This leads to the conclusion that more than one technology issue needs to be addressed in order to achieve a factor of two cost reduction.

In a study by Polsky *et al*. (2008) a hypothetical well construction exercise was performed in which the steps, tasks and tools involved in the construction of a prospective baseline EGS well were explicitly defined in terms of sequence, time and cost. A task and cost based analysis was conducted to develop a deeper understanding of the key technical and economic drivers of the well construction process. The starting point of the exercise was to provide a detailed account of how the well of interest might be constructed using today's technologies.

The case study's well cost distributed across tasks is given in Figure 5. It is implied that well construction cost reduction efforts will have to focus on multiple elements because the ability to substantially reduce any single task cost is inherently limited.

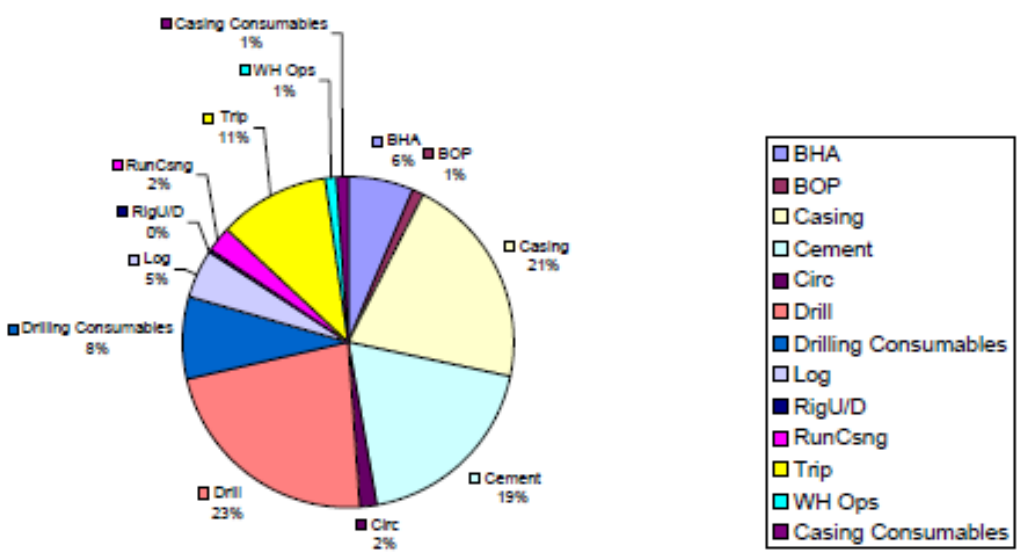

Figure 5 Well cost breakdown by task categories for EGS case study by Polsky et al. *(2008).*

Teodoriu & Cheuffa (2011) discuss the cost drivers involved when drilling a well, suggesting some causes of different costs of petroleum and geothermal well construction. Key cost driving elements of geothermal well construction are pinpointed, e.g. large production casings, deep wells in hard rock formations, tectonically challenging geology and high temperatures. According to a study on German drilling activities, a well cost reduction of 18 % requires a reduction of drilling rig costs, drilling and trip time with 50 % respectively.

Thorhallsson (2011) reviews advances made in geothermal well construction during the past decade. Emphasis is placed on the actual time spent drilling, being only 30-40 % of the total time constructing the well. The rest of the time is spent rigging up and down, installing and cementing casings, and solving various types of problems. Improvements in reducing trouble time can therefore significantly improve total costs. A number of measures are discussed, including increased bit life, Measurement While Drilling (MWD) tools, automation (specifically of the pipe handling), improved casing cementing procedures, new rig types, etc.

The next section discusses some of the means that can be implemented in order to reduce geothermal well costs. The discussion is based on experience from the petroleum industry, which in many respects obviously differ from the geothermal applications. Many challenges are nevertheless similar, and means for cost reduction in petroleum cases will also be relevant for the geothermal cases.

MEANS FOR IMPROVED DRILLING PERFORMANCE AND REDUCED WELL COST

There are a number of approaches to reducing cost and improving drilling performance (see e.g. Blankenship *et al*., 2005). The present approach involves investigating two principal strategies for reducing cost of well construction:

1. Increased bit penetration by utilizing new technologies, tools and methods
2. Implementing procedures (e.g. automation) for increasing the efficiency of the well construction process in terms of reduced crew expenses, fewer trips, improved safety etc.

The two strategies may well be interconnected as new procedures may require new measurement technologies, new technologies for drilling may require different operating strategies, etc. Obviously, new equipment and technologies are in many cases combined with new operating methods and procedures. The present investigation is primarily based on experience from petroleum well construction, investigating synergies, further development of existing technologies, and assessing impacts for the field of geothermal well construction.

In terms of pinpointing cost drivers, also important organizational issues are discussed in this section. The starting point is how work is organized in today's oil and gas drilling operations.

Systematically reviewing the entire operation is also considered important when aiming for more cost-effective geothermal well construction. Key principles of a software tool for probabilistic well cost estimation are also presented in this section.

Increased Bit Penetration Technologies

Various technologies for increased bit penetration compared to conventional drilling technologies have been suggested and are under thorough investigation. One of the earliest reviews on novel and exotic methods to attack rock is done by Maurer (1968). A comprehensive review of drilling methods relevant for deep geothermal is made by Teodoriu & Cheuffa (2011).

The classical, and maybe the most efficient, method to transmit energy to the end of a borehole is by mechanical energy. In general there are three basic methods of mechanically attacking rock: percussive, rotary and combined rotary-percussive action.

In percussion drilling the drill bit applies a force perpendicular to the rock surface and the bit moves into the rock surface, forming a crater beneath it. In rotary drilling the drill bit applies a constant force perpendicular to the rock surface while a torsional force moves the bit parallel to the surface. Rotary-percussive drilling is a hybrid form of drilling, where the weight-on-bit and the angular velocity are acting as in conventional rotary drilling and a percussive force on the bit moves it into the rock at an angle to the surface.

With respect to efficient net rate penetration in hard rock drilling there are some parameters in the drilling process that are considered essential and may be different from drilling in softer soil and sediment based formations. Firstly, it is desired to deliver as much as possible energy per area to the bottom of the hole. This can be done by generating higher pressing forces in percussive drilling or rotary drilling. However there are some limitations due to the current materials used in today's drill bit designs and this puts some constrains on the maximum stresses that can be imposed to the rock surface. Secondly this energy

increase may be achieved through a higher angular velocity in rotary drilling or through higher impact frequency in percussion drilling, which thereby is delivering a higher amount of energy for a specific time. Currently the maximum excitation frequency is around 100 Hz (Hydraulic tophammer Atlas Copco 3038).

If the energy is delivered through a percussive stroke the limitations may be connected to the length of the longitudinal stress pulse. A short stress wave/pulse may then not be able to move the drill bit far enough into the crushed surface. A long stress wave on the other hand requires the striking hammer, or piston, to be longer and correspondingly heavier which then requires a much higher energy input to accelerate. Besides delivering more energy to the rock formation facing the drill bit there is also a large correlation between rock fracturing efficiency and the shape of the mechanical pulse running through the drill string to end in the drill bit. In general the most instant pulse, i.e. a higher frequency in the Fourier spectra, is mostly desired for hard rock formations although a certain pulse shape may be optimal for a specific rock formation. Even though the elastic pulse may be optimised for a specific rock formation the fractured rock surface will create boundary conditions and a new response to the following strokes. The complexity of this interaction implies huge improvements to be done by measuring and controlling the longitudinal stress waves in this system.

The present subsections mainly deals with a few examples of promising developments taken from a Norwegian context, being developed based on experience with petroleum well construction, and potentially offering significant technology improvements in the near future.

Sonic or Resonance Drilling

These are some systems that utilises combinations of percussive and rotary drilling. One example is *Resonator*[2] that uses a magnetically controlled mass who is moving between two springs and creates a striking force with high energy efficiency and supposedly high control. Another example is called sonic drilling where rotating out of balance weights are used to create a sinusoidal striking force with high frequency and low energy input. These methods (i.e. products) have shown impact frequencies of around 120 Hz and are currently targeted to geothermal drilling.

[2] See http://resonator.no/

New Hammer Designs

New percussion drilling concepts are currently being developed (*Pen-Rock* AS[3]) where a new hammer design creates the percussion action. The technology is under development but the company claims the ROP to be up to 30 m/hour and reach up to 10 km. It is designed to drill in any but the softest formations. Crystalline rocks like granite, gneiss etc. seems to be well suited.

Electro Pulse Drilling

The Electro Pulse Drilling method is a technology under development and evaluation in Norway. An electrode pair is touching the rock surface and a 1-500,000 Volt electric pulse creates a plasma based explosion that breaks the rock in front of the electrodes (Rødland, 2004). The method has shown promising results with high ROP and large cuttings were achieved. However there might be some limitations to moderate ambient temperatures, i.e. as the rock is brittle and the temperature gradients are high. At higher temperatures and pressures the efficiency of this principle is decreasing and the rock might also become more ductile. However, this may be most promising as a combination technology to rotary or percussion drilling.

An Electrically Driven Drilling Concept

Traditional drilling is usually based on a concept where a motor at the ground level is driving a rotary table that is rotating the whole drill string. This string is assembled of a number of sections and gravity is the main forward driving force in the case of vertical downward drilling. The *Georigg* concept[4], on the other hand, is one example of new technology that can contribute to significant reduced drilling cost due to simplifications of the whole operation. The concept is based on:

- Use of continuous non-rotating carbon drillstrings that also support use of electric power and communication cables to drive the downhole equipment.
- Use of well tractors for pulling the wellstring and forward thrust of the bottom-hole assembly and drill bit.
- Use of bottom-hole electric motors that are mechanically driving the drill bit.

[3] See http://pen-rock.com/
[4] See http://www.georigg.no/

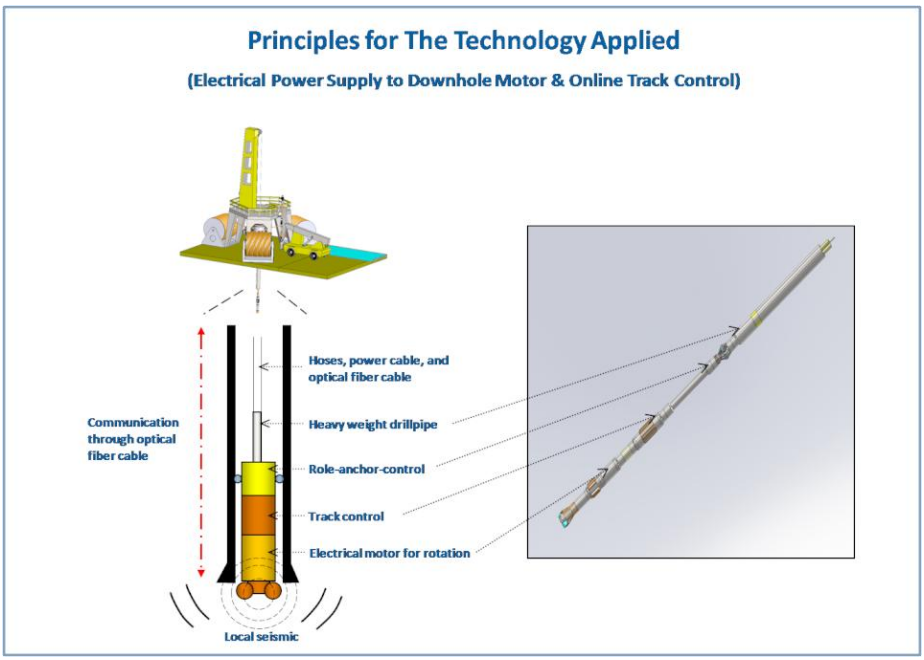

Figure 6 The Georigg concept (http://www.georigg.no/)

Some of the new technological building blocks in the core of this concept include:

- A tailor-made electric motor connected to the drill bit.
- Continuous carbon drill string
- Down-hole compact and robust electromechanical tractor
- Electromagnetic geo-steering tool including seismic-while-drilling sensors

The developing company claims, based on preliminary calculations, that drilling cost may be reduced by the order of 50 % compared with conventional oil and gas drilling.

Continuous Motion Rig

The *Continuous Motion Rig* (CMR) concept allows for jointed pipes to be run or pulled in a continuous manner. In a study described by Grinrød & Krohn (2011) the characteristics of the rig concept are investigated. A 750 ton system has been studied in a Joint Industry Project. In terms of geothermal drilling, a lighter rig is probably more suitable.

The CMR concept is based on automation of a number of operations on the rig, in terms of 1) simple surface operations involving standard equipment and repetitive actions, 2) complex surface operations with many different items and operations, and 3) drilling automation. It is believed that the CMR concept can enable deeper drilling than what is attainable today. Further, the time of drilling is assumed to be reduced, and the target of the project is 30-40 % reduced time spent on well construction.

Automation of the Drilling Process

The principles of the rotary drilling process have been relatively unchanged the last 100 years. The drilling rigs have become more robust and reliable, and several of the drilling operation procedures have been mechanized and remote operated. However, there is still a lot to be done within the field of improving the drilling operation, especially in relation to automated solutions. Literature on automation of geothermal well construction processes is relatively scarce. An evaluation of various automated drilling technologies and their potential when used for geothermal drilling has been performed by Nygaard *et al*. (2010). Spielman *et al*. (2008) describe a system for drilling of deep geothermal wells, implementing an automated closed-loop downhole tool for vertical steering. Other examples of Measurement-While-Drilling (MWD) or Diagnostics-While-Drilling (DWD) in geothermal are described by e.g. Prairie & Glowka (2000), Mansure *et al*. (2000) and Finger *et al*. (2003). Prevedel *et al*. (2010) describe a semi-automatic geothermal rig concept (*InnovaRig*) with automated pipe handling.

The terms “automated”, “remote controlled” or “manual” are sometimes mixed, but the distinction is relatively clear, and is best explained using an example involving valve control. If the control of a valve is manual, then the operator turns the valve handle and opens or closes the valve. If the valve is remote operated, then a hydraulic or an electrics actuator is mounted on the valve handle, and the valve can be opened or closed by pushing the close or

open button. If the valve is automated, then the valve opening is automatically adjusted according to an external reference, for example the pressure upstream the valve.

When comparing the use automation in drilling and in other industries, one will notice that the drilling industry has a relatively low level of automation. In other industries, automation is introduced in order to improve both safety and the quality of the process in question. The drilling industry often compares the risks involved in drilling with the risks involved in aviation. And in a drilling operation, the driller's tasks and responsibilities are often compared with the tasks and responsibilities of the pilot. The last hundred years of aviation automation technology development is tremendous. The first trans-Atlantic fully automated flight was conducted in 1947, and were referred to as "Push-Button Flying". Take-off, navigation and landing were fully automatic. Today, automatic landing systems are required in bad weather, and the pilot is only observing the automatic landing system for erroneous behaviour. Drone aircraft has also been taken into use for more and more flight operations the last 10-15 years.

In a managed pressure drilling (MPD) operation, used for oil and gas exploration wells, focus is on having a correct pressure in the wellbore at all times during the operation. The downhole pressure is influenced by several factors, such as the density of the drilling fluid, the friction pressure drop, loss of drilling fluid, the rig pump flow rate, the MPD choke opening, and the movement of the drillstring. One should assume that all these factors would be controlled by a uniform control system. This is not the case in drilling operations. In a drilling control system, the control system of the main pump and drawworks is coming from a separate vendor than the control system of the MPD choke valve vendor, and the two control systems are not sufficiently integrated. The downhole sensor system is further not directly connected with the rig pump control system. Such a critical downhole sensor should be integrated using a real-time field-bus type of interface. In aviation, however, all factors that influence the flight of the aircraft are conducted using a control system. This includes all the various actuators, from the tail of the aircraft, the flaps on the wing and the main engines giving thrust. In addition, this overarching control system is duplicated or triplicated in order to have redundancy.

Automation Systems

There is a range of automation solutions that already have been developed for drilling operations and already is taken into use and several more that are under development. A drilling operation monitoring system that is constantly evaluation the conditions of the wellbore, is the *Sekal*[5] *DrillScene* monitoring system. This system is monitoring all the parameters of the drilling operation, and calculates the expected behaviour of the wellbore using a combination of both mechanical and hydraulic wellbore models. By comparing the measured and the calculated values of the wellbore, the system automatically alerts the drilling crew when the operating conditions are changed, and actions must be taken to avoid a deterioration of the wellbore. Effects that are typically monitored are cuttings transportation and increased torque due to poor hole-cleaning. Another system that is being introduced is the Sekal *Drilltronics* system. This system calculates a safe envelope for the driller operations. As moving the drillstring affects the downhole pressure, the system calculates the safe limits in order to insert or extract the drillstring. In addition, some operation sequences that are typically handled by the driller are programmed automatically by the system. This is the pump startup sequence and the friction test procedure. Some safeguarding functionalities with respect to packoff detection and pump shut-off are also included.

In petroleum drilling, the handling of an influx situation is critical. Typically, the influx detection is performed manually by the mud logger. In order to circulate out for the influx, both the driller and the drilling supervisor are operating the main rig pump and the rig choke. The correct coordination between the rig pump operation and the rig choke operation of the well control procedure is critical. Systems are now being developed to both detect influx automatically and to automatically coordinate the operation of the rig pump and the rig choke (Carlsen *et al*., 2008).

Monitoring of the drilling fluid properties is extremely important both in petroleum drilling and in geothermal drilling. Manual inspection of the drilling fluid using a mud balance or a Marsh funnel is well proved, but out-dated methods. A system currently being tested in Norway is called the "Instrumented Standpipe", where a few "off-the-shelf" differential pressure sensors with high accuracy are mounted on the standpipe (Nygaard, 2011). Using this system both the density and the viscosity is measured constantly during the drilling operation. This ensures a correct monitoring of all the fluid entering the wellbore.

[5] See http://sekal.com/

MPD operations have for the last decade been utilized in drilling projects where there are narrow pressure margins. The current generation of MPD systems involves extra crew of the rig. There is currently under development a more user-friendly system that is enabling the driller to monitor and operate the system. The MPD system can be referred to as "Driller Operated MPD" (Nygaard, 2011). When introducing this kind of user-friendly MPD systems, then the cost of MPD operation will be reduced.

All these systems that are mentioned lay the ground for a new level in drilling operation. This new level of drilling control can be referred to as coordinated control. Coordinated control focuses on operating the equipment automatically according to some overarching specification from the driller (Breyholtz, 2011). The coordinated control system operates the rig pumps, the top drive, the draw works, and the MPD choke system. The driller is defining the sequence and operating limits, but the coordinating control system is optimizing the operation of each individual machine. Such systems have already been taken into use in several industries. What, then, are the barriers for automation system implementation in the petroleum industry?

Lessons learned from other industries when introducing automated solutions show that automation and introduction of new automation technology always lead to changes in the workforce composition and the everyday tasks for the remaining workforce. When automation systems are being implemented on a drilling rig, the various roles of the drilling crew members will therefore be changed. Some of the proposed automation technologies will most probably lead to a radical change of existing procedures, and will lead to changes in both drilling crew organization and drilling crew training. In addition, these supervisory drilling control systems also challenge the existing structure of the drilling industry.

"The Organizational Factor"

The offshore rigs today are very different in organizational set-up and role definitions. However, the set-up is in general heavily influenced by a North-American tradition, and the drilling operations are carried out by personnel from the operator, drilling contractor, and service companies. The main roles and responsibilities are:

- Operator
  - *The drilling superintendent* is responsible for planning and executing all aspects of the drilling program. He is located onshore.
  - *Drilling supervisor* is responsible for the drilling operation (i.e. ensuring that all activities are performed safely and efficiently).
- Drilling contractor
  - *Toolpusher* is the location supervisor for the drilling contractor, and is responsible for equipment and personnel. The toolpusher also serves as an advisor to many personnel on the rig, including the operator's representative/the company man.
  - *Driller* is supervisor for the rig crew, and the main responsibilities concern supervision of the operation and ensuring that the activities are run in accordance with established procedures and guidelines.
  - *Assistant driller*'s main responsibility is to assist the driller in operating drilling and mud circulation equipment. Supervision of Derrickman and Roughnecks is also a central responsibility.
  - *Derrickman* is responsible for volume control and maintain the drilling fluids conditions. He/she also handles the drill pipe when tripping out.
  - *Roughnecks* perform most of the manual work in maintaining drilling equipment and extracting hydrocarbons, and follow up tasks assigned by the Supervisor.
  - *Deck crew* is responsible for all operations and equipment on deck.
- Service companies
  - Some of the most common roles/positions (from several companies) represented on the rig are ROV operators, directional drillers, MWD, mud engineers, mud loggers, sample catchers, and cementers.

This overview shows that there are many people (holding various roles) from numerous companies involved in offshore drilling operations. Naturally, this has consequences for drilling costs. For example, the total cost reduction as a result of removing one person from an offshore rig on the Norwegian Continental Shelf is estimated to be around NOK 16,000 ($ 2,600) per day (Erikson *et al*., 2011). However, the business models in offshore drilling today are different for operators and for drilling contractors and service providers. The business models of contractors and service companies have traditionally been centred around a day rate service, and they have therefore not had much of a motivation to change (Hsieh, 2011). Cost reduction as a result of automation of drilling processes necessitates a closer collaboration and cooperation between the operator, drilling contractor and service companies, which again may require a change in business models. Some

of the automation technologies described earlier will most probably lead to a radical change of existing procedures, and will lead to changes in both drilling crew organization and drilling crew training. Thus, the existing organizational setup and reluctance/conservatism regarding business model change is one of the most important factors explaining why the degree of automation is low (and the costs are high) in offshore drilling.

Another important factor explains the conservatism regarding work process organization, is the way drilling is exposed to risk. From other sectors of working life (e.g. mining) it is known that high risk is often associated with resistance towards change, and maybe for good reasons. Employees working in high risk environments will naturally be more sceptical when major changes in technologies and/or procedures are introduced. Risk, or fear of accidents, may also function as a power base for those who have an interest in keeping status quo. In this way risk exposure is an important factor for the lack of technological progress and cost efficiency.

As already mentioned, offshore drilling operations have some common characteristics that are influenced by what may be called the North-American model. Even though these common features exist, the costs of drilling operations are also influenced by different regulatory regimes. In Norway for instance, the regulations of offshore drilling are considered to add much more costs to the operations than in areas in Asia. When discussing cost reduction in drilling operations, these regulatory regimes have to be considered as an important factor. However, it seems that drilling onshore is much less regulated. This may represent both a problem and an opportunity for the geothermal well construction and the development of new drilling technologies.

A Structural Approach to Well Cost Estimation

Estimation of well cost, as discussed above, is essential both in the petroleum and geothermal industries. Here, the principles of a tool for probabilistic well cost estimation – developed for petroleum with potential relevance for geothermal – are presented.

The software tool *Risk€* is developed by IRIS for planning of construction of oil and gas wells, in addition to offering decision support with regards to cost and duration. A general discussion of the well cost estimation and modelling principles used is given by Løberg *et al*. (2008).

The strength of Risk€ compared to traditional well cost estimation is that of the probabilistic based cost estimates, showing a more complete uncertainty picture regarding well construction cost and duration. The risk analysis is well specific, which means that it takes into account variations between different fields and wells. It is based on a stochastic modelling approach, using Monte Carlo simulations. Input to the different operations involved in the model is based on expert inputs from different disciplines.

Costs and duration results are presented using distributions, allowing consideration of both the most probable values and the total spread. Sensitivity analysis is also provided in order to make adjustments on parameters related to critical operations and undesirable events. This allows for comparison of different well designs.

Analysis results from the tool include:

- Quick results for drill depth and cost versus time based on expected values in probability distributions for input parameters
- Percentile curves for drill depth versus time
- Distributions of the total well construction cost and duration
- Probability of finishing the well construction within user defined cost and time limits
- Comparison of different solutions for the well construction process
- Sensitivity analysis
- Cost breakdown

The construction of the well is divided into several sub-operations for which the cost and duration can be expressed by probability distributions. That is, the variation in cost and duration for each sub-operation is provided by experts on the well construction process.

The analysis is performed by running simulations of all operations and associated undesirable events. Results are given as probability density functions and histograms, which fully reproduce the uncertainties in construction time and expenses. Both readily calculated results based on the expected values in the input parameter distributions, and advanced results based on Monte Carlo simulations can be presented.

The phases involved when establishing a well is considered in the following steps:

1. Mobilization of rig
2. Spudding
3. Placement of blowout preventer (BOP)
4. Drilling
5. Abandonment

Phases mainly consist of input parameters for duration of different operations, fixed costs and cost

rates. Alternatively, input parameters are defined by velocity and distance, giving the duration of a certain task indirectly.

In all phases, one or more sub-tasks are identified, thus covering the entire chain of events involved. For instance, in the spudding phase, three different technologies are considered, namely jetting, hammering and drilling top hole. The drilling phase deals with the construction of a new hole section, with or without running casing string and cementing. The user can specify a number of alternatives giving project specific and detailed input to the calculations. Alternatively, Risk€ offers default options based on typical project parameters. In this case, the software generates the standard operations that must be performed within each phase. However, the operation list can be edited by the user, allowing removal and adding of operations manually. The input list is given in Figure 7.

The five phases included in Risk€ correspond mainly to the *development* phase and to some degree to the *feasibility* phase, as structured by Barbier (2002) for geothermal project development (see also Figure 1). Using the Risk€ tool, the prior investigations in terms of reservoir mapping, area selection etc. are not considered. The equivalent to a geothermal exploitation phase, i.e. production of oil and gas, is also not considered. The well completion phase is as of yet not covered, but is planned to be included in future versions of the tool. Costs and durations related to any items not covered by the tool may however still be included in an analysis, but must then be specified as a lump-sum figure without a refined cost-breakdown.

Generally speaking, geothermal projects may consist of a number of options making modelling of development significantly more comprehensive than for development of a single well (for oil and gas in the case of Risk€). In the tools developed for decision support for geothermal projects, simplifications are done in order to be able to make estimates and prognosis of energy production. Basing a new decision support tool on the structure of Risk€ would therefore require implementation of physical models or library data offering generic or default calculations of performance in the various phases.

Risk€ input parameters						
		Basic well input				
			Casing program	Open hole section	Riser	
		Cost rates (applies to all phases)				
		Rig rate Support costs	Spread rate	Drilling/BHA costs	Wellhead costs	Fixed costs
		Additional costs:				
		Risk events: Probability of occurrance/cost impact				
Operational phase		**Operation-specific costs**				
Mobilise		Distance to move	Move velocity	Rig up duration	Skid rig distance	Skid rig velocity
Spudding	Hammering	Rig up duration	Rig down duration	Conductor section lenght	Conductor accessories cost	Hammering speed
	Jetting	Make up jetting assembly Conductor cost	Break jetting assembly Jetting speed	RIH speed	POOH speed	Conductor accessories cost
	Top hole	ROP	Bit cost	Make up BHA	Break BHA	RIH speed
Drilling		POOH speed Cement volume	Conductor section lenght Cement slurry cost	Conductor accessories cost	Conductor running speed	Cementing duration
		Section length	ROP	Expected bit life	Bit size	Bit cost
		Bit change duration Fluid cost	Circulation duration Waste treatment	Drilling fluid hole volume Make up BHA	Drilling fluid surface volumes Break BHA	Expected fluid losses RIH speed
		POOH speed Casing run speed LOT duration	Casing/liner length Cementing duration Log duration	Casing/liner accessories cost Cement volume Log cost	Cast cost Cement slurry cost	Casing services LOT formation length
BOP		Nipple up BOP duration	Pressure test BOP duration			
Abandon		Rig up/run logs duration	Rig up/run logs cost	Nipple up BOP duration	Deanchor/Rig down duration	Move out duration
		Cement plugs duration	Cement volume	Cement slurry cost	Corrosion cap duration	Corrosion cap cost

Figure 7 Inputs for the Risk€ well construction cost estimation tool.

The Risk€ model is especially suitable when historical data are insufficient and when expert judgement is necessary. Indeed, there are insufficient geothermal well cost historical data to create an index based on geothermal wells alone (Tester *et al*., 2006). Further, drilling cost data are scattered due to that drilling cost records are often missing important details, or the reported drilling costs are inaccurate. The Risk€ model takes into account the well construction in different levels, and establish a flexible platform for relating uncertainty statements to the quantities which contribute to the uncertainty of the cost and duration of well construction. While it is clear that Risk€ would need adaptation to take into account the specifics of geothermal drilling, it could very well prove to be a viable point of departure, especially in terms of modelling approach, for more accurate well construction cost estimates.

WELL COST ESTIMATION – A CASE STUDY

To further illustrate some of the aforementioned discussions, Risk€ simulations were performed on an oil and gas land well provided from an operator company. While the case itself is realistic, some of the inputs have been modified for the sake of illustration, and several cost items do not necessarily apply for an equivalent geothermal well. As such, the following section should be perceived as an attempt to show how well construction costs may be modelled and the effects which cost reducing measures may have – not as an attempt to model the true costs of a geothermal well.

The case data is for a land rig with four cased sections with casing shoe depths 45, 305, 1035 and 1505 meters, respectively. Outer diameters for the casing sections are 20, 13 $^{3}/_{8}$, 9 $^{5}/_{8}$ and 7 inches, respectively. The well construction phase consists of mobilizing the rig to the desired location, spudding by hammering for a section length of 40 meters for the conductor pipe, drilling of a 17 ½" hole, assembling and pressure testing of a BOP, and drilling of a 12 ¼" and 8 ½" hole. Cost elements for these six operational phases cover only those listed in Figure 7.

In the base case example, the rig rate is set to 50,000 $/day. The support cost for Mobilization, covering office overhead, support consultancy, transportation and other expenses is uniformly distributed between 2,000 and 3,000 $/day, fixed at 3,000 $/day for Spudding, and uniformly distributed between 6,000 and 8,000 $/day for BOP installation and testing. The former phase also includes a fixed cost rate covering equipment expenses estimated to 50,000 $/day. Each of these three phases also includes some other cost elements not elaborated on here.

For the Drilling phases, the base case values are shown in Table 1.

Table 1 Base case cost values for the drilling phases of an example case

Phase	Cost rate	Value ($/day)
Drill 17 ½"	Drillstring/BHA	14,000
	Fixed cost	5,000
	Wellhead cost	80,000
	Support cost	6-8,000
	Spread rate	50,000
Drill 12 ¼"	Drillstring/BHA	18,000
	Fixed cost	5,000
	Wellhead cost	80,000
	Support cost	6-8,000
	Spread rate	50,000
Drill 8 ½"	Drillstring/BHA	25,000
	Fixed cost	8,000
	Wellhead cost	80,000
	Support cost	8-12,000
	Spread rate	50,000

Besides these cost rates, each Drilling phase contains many detailed cost elements which will not be presented here. Each Drilling phase does however cover circulation, bit change, drilling fluid injection and waste treatment, casing running, cementing, leak-off tests and tripping. The rates of penetration are for the 17 ½" section triangle distributed T(13, 18, 20) m/h, for the 12 ¼" section T(9, 12, 14) and for the 8 ½" section T(7, 11, 12). Such ROPs could naturally be significantly lower for many geothermal wells drilled in hard rock formations.

Figure 8 shows drill depth versus time for a "bad and good" case, represented by the 10th and 90th percentile curves, respectively, giving scenarios of 24.5 to 28 days required to drill down to target depth of 1505 meters. The duration plot shows a mean duration of 26 days, with a minimum duration of 23 days and a maximum duration of 33 days. The mean total cost is $4.2 million, with a minimum cost of $4.0 million and a maximum cost of $4.7 million. The main cost contributors to the total cost are unsurprisingly the Drilling phases, especially the two latter.

It is in the following assumed that this estimated well construction cost of the project is viewed as too high by stakeholders, who will not allow the project to commence unless the total cost is lower to meet budget restrictions. To try to reduce costs, personnel and equipment costs are investigated further.

Figure 8 Drill depth versus time for the example case, showing estimated duration and cost

Over the years, the oil and gas industry has seen an increase in the use of automation of various tools and equipment, to increase performance, reliability and enhance safety. While there are many operations today which are fully automated, the opportunities for automation have by no means been exhausted. A particular characteristic for the oil and gas industry, which could in part explain why drilling is by and large still a non-automated operation, is that the cost-incentive for the well construction is small, compared to e.g. geothermal drilling, as the revenue streams are incomparably higher for oil and gas drilling. However, in cases where well construction costs are of significant importance, automation of procedures could be an area of improvement and represent a cost reduction.

There is naturally a vast array of possible drilling operations which in principle could be automated. In this example, a selected few have been looked into, based on an NTNU report as an assignment by a major oil and gas operator (Erikson *et al*., 2011). The report identifies several functions which according to the operator could in part be automated:

- Casing crew: One could introduce a tool such as the *UniTong*, remotely operated tubing handling system requiring no manual handling on the drill floor. This would eliminate the need for roughnecks to handle the tongs, minimum 2 persons per shift. Also, connection of the completion string could save 4 persons travelling to the rig, and one would not need separate casing and tubing crews.
- Service company and roughnecks: Actions could be taken to reduce or eliminate the need for a service company to perform logging and certain tests, through better training of roughnecks, establishing a service centre at the service company's site, better tools to remotely operate commands, etc.
- Mud system: Automation of the mud mixing system could typically involve auto transferring fluids and bulk powder, auto density and auto mud mixing.
- Cementing: Systems for auto mixing of the cement and remote control of the cementing operation could yield parts of the cementing crew redundant. There is however regulatory requirements stating such crews must be on site, since the cementing equipment is classified as an emergency system.

The report attempts to quantify the effects of automation in terms of daily cost rate savings. Assuming that the above actions were taken, 15-17 persons could be removed from the site. Assuming a daily cost rate of 2,560 $/day, this would amount to 38,400-43,520 $/day.

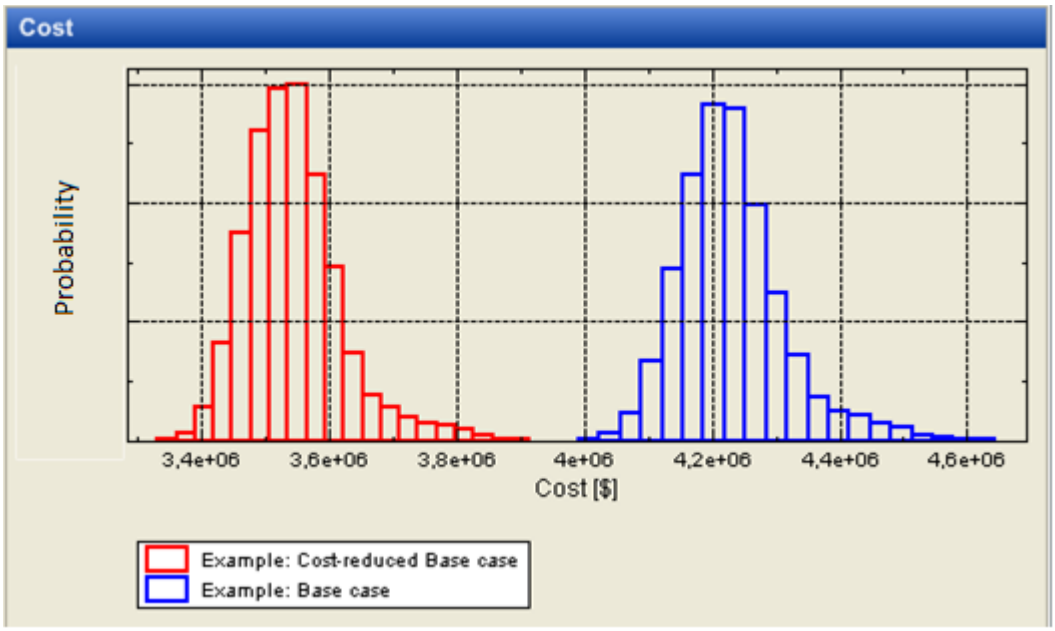

Figure 9 Cost in terms of probability for the example Base case and the Cost-reduced Base case

A comparative Risk€ simulation was performed between the base case and a "cost-reduced base case", in which the cost savings of the proposed measures have been introduced. As with any new equipment, prices would be higher than existing equipment in the early stages, and drop as competition increases and the use becomes widespread. For instance, the typical cost of the UniTong is twice that of an iron roughneck, but rental expenditures would be eliminated.

To attempt to reflect that new equipment is more expensive (in the short term), an equipment cost increase of 30 % was used for the Drilling operations. Certainly, one could discuss the magnitude of the cost reductions, the equipment cost increase, or the possibility of implementing the proposed or other automation processes, but again the example only seeks to illustrate how one could efficiently model well construction costs and reflect how cost saving measures might impact the well planning process.

Figure 9 shows that in terms of overall cost savings (the duration in the cost reduced case is approximately the same as the base case), the mean total case for the alternative case is $3.5 million, with a minimum cost of $3.3 million and a maximum cost of $3.9 million. It is worth noting that since the total cost is a function of total duration, the greater the duration the greater the deviations from the base case would be. If for example the rate of penetration is significantly decreased, this would yield a relatively larger cost reduction.

DISCUSSION OF POSSIBLE IMPROVEMENTS AND IMPLICATIONS

In order to increase the bit penetration rate and lower drilling costs some technology areas are already in focus for research and development. These include drill bit materials that can withstand higher stresses and temperatures, new energy transfer principles such as electro pulse drilling, as well as sensor and actuator technologies for measuring and controlling the motions and forces of the drill bit. Several new drilling rig concepts are also under development, possibly offering significant reduction in well construction cost. The importance of technology transfer from other areas of drilling, especially the petroleum industry, is apparent.

Numerous automation systems for drilling operations have been developed, and many more are under development. Automation of petroleum drilling represents a great potential for increased efficiency and effectiveness, as well as expected HSE improvements. However, there are several factors contributing to a resistance regarding role alterations and a relatively slow adoption rate of automation systems. The nature of the business models of the involved companies represents one important factor. Secondly, the high-risk environment leads to a scepticism regarding major changes, and a third factor concerns the regulatory regimes that the involved companies must act in accordance with. These factors should also be emphasized when considering the potential for cost reduction related to automation of geothermal drilling. However, it is

believed that both the risk levels and regulatory regimes in geothermal drilling to a lesser extent (compared to offshore drilling) represent factors that hinder a cost-effective use of technology and implementation of necessary work processes. More flexible business models of the involved actors may also be advantageous in this respect. In this perspective, implementation of automation systems in geothermal drilling may prove valuable for the petroleum sector.

There is undoubtedly a challenge of accurately assessing well construction costs in a geothermal context, in part due to a lack of accurate historical data. However, the use of a structured tool with well-defined operational phases and cost elements, together with a shift in focus from the use of historical data towards quantifiable assessments based on expert judgement, could improve such assessments and additionally clarify and improve the overall transparency in the decision making process.

Through development of new technologies, methodologies and systems for geothermal well construction, where reduced cost is a definite requirement, it is believed that competence transfer in the direction from geothermal to the petroleum industry may be viable.

CONCLUSION

It is considered essential that more effective technologies, procedures and cost-estimation tools are implemented in order to reduce the cost and financial risk of geothermal well construction. An evaluation of relevant measures has been performed, suggesting that significant improvements can in fact be achieved. However, a broad approach involving both technological progress and organizational changes will be needed.

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