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Enhanced Geothermal Systems (EGS) Well Construction Technology Evaluation Report

Yarom Polsky, Louis Capuano Jr., John Finger, Michael Huh, Steve Knudsen, A.J. Chip Mansure, David Raymond and Robert Swanson

Prepared by
Sandia National Laboratories
Albuquerque, New Mexico 87185 and Livermore, California 94550

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Yarom Polsky, Steve Knudsen, David Raymond and Michael Huh
Geothermal Research Department, Sandia National Laboratories

A.J. (Chip) Mansure and John Finger
Sandia National Laboratories, Retired

Robert Swanson and Louis Capuano, Jr.
Thermasource Inc.

Abstract

Electricity production from geothermal resources is currently based on the exploitation of hydrothermal reservoirs. Hydrothermal reservoirs possess three ingredients critical to present day commercial extraction of subsurface heat: high temperature, in-situ fluid and high permeability. Relative to the total subsurface heat resource available, hydrothermal resources are geographically and quantitatively limited.

A 2006 DOE sponsored study led by MIT entitled "The Future of Geothermal Energy" estimates the thermal resource underlying the United States at depths between 3 km and 10 km to be on the order of 14 million EJ. For comparison purposes, total U.S. energy consumption in 2005 was 100 EJ. The overwhelming majority of this resource is present in geological formations which lack either in-situ fluid, permeability or both. Economical extraction of the heat in non-hydrothermal situations is termed Enhanced or Engineered Geothermal Systems (EGS). The technologies and processes required for EGS are currently in a developmental stage. Accessing the vast thermal resource between 3 km and 10 km in particular requires a significant extension of current hydrothermal practice, where wells rarely reach 3 km in depth.

This report provides an assessment of well construction technology for EGS with two primary objectives:
1. Determining the ability of existing technologies to develop EGS wells.
2. Identifying critical well construction research lines and development technologies that are likely to enhance prospects for EGS viability and improve overall economics.

Towards these ends, a methodology is followed in which a case study is developed to systematically and quantitatively evaluate EGS well construction technology needs. A baseline EGS well specification is first formulated. The steps, tasks and tools involved in the construction of this prospective baseline EGS well are then explicitly defined by a geothermal drilling contractor in terms of sequence, time and cost. A task and cost based

analysis of the exercise is subsequently conducted to develop a deeper understanding of the key technical and economic drivers of the well construction process. Finally, future research & development recommendations are provided and ranked based on their economic and technical significance.

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1 Introduction

The concept of Enhanced Geothermal Systems (EGS) has long been recognized by geothermal energy experts as being the necessary technology for substantially increasing the contribution of geothermal energy to the nation's production of domestic electricity. This belief has been further bolstered recently by the 2006 DOE sponsored study led by MIT entitled "The Future of Geothermal Energy", hereafter referred to as the MIT Report. Commercial demonstration of EGS has not been achieved to date, although there are at least three ongoing pilot projects with this aim. The MIT Report therefore largely represents a feasibility study based on historical data and the current technical understanding of the geological conditions, physical processes, operational steps and technologies believed to be required to realize EGS. An examination of the assumptions and conclusions of the MIT Report, as well as a broad survey of existing industry technology in the context of EGS, has also been recently published in the 2008 DOE Geothermal Technologies report "An Evaluation of Enhanced Geothermal Systems Technology". Both reports represent significant synopses of the current status and direction of EGS research and development. This document will attempt to provide a more focused and in-depth investigation of the technologies currently available and needed for EGS well construction.

This assessment of well construction technology for EGS considers two perspectives:
1. The ability of existing technologies to develop EGS wells.
2. The identification of critical well construction research lines and development technologies that are likely to enhance prospects for EGS viability and improve overall economics.

The foundation for the study will be a hypothetical exercise performed by a geothermal drilling contractor in which the steps, tasks and tools involved in the construction of a prospective baseline EGS well are explicitly defined in terms of sequence, time and cost. A task and cost based analysis of the exercise is then conducted to develop a deeper understanding of the key technical and economic drivers of the well construction process. Content and perspective for both the exercise and analysis are drawn from the experience of project personnel, past DOE sponsored assessments, existing literature, and interviews with geothermal, oil and gas and other industry professionals.

It is important to emphasize at the outset that this exercise is not intended to represent the final word on EGS well design. Many crucial "to be determined" aspects of EGS implementation related to creating and operating the reservoir can impact well construction. For example, achievable flow productivity, fracture placement and spacing, and zonal isolation strategies are a small subset of the interrelated system level issues that are likely to ultimately affect well profile and geometry. Current understanding of issues of this type is based on the limited availability of EGS data to date and will certainly continue to evolve with the lessons learned from EGS pilot projects. As our understanding of how to implement EGS improves, so will our understanding of the well specification required to make EGS economically successful.

Because of this uncertainty, the hypothetical well construction exercise and analysis in this report primarily represents a methodology for better understanding well construction R&D needs. Although some conclusions of the analysis will likely hold irrespective of the accuracy of the case studied, others may diminish in importance if the ultimate commercial EGS scenario is significantly different than the presented baseline scenario. Additional technology areas meriting focus will also emerge as well design complexity increases in conjunction with a better grasp of EGS implementation.

This report will begin with a discussion of the considerations necessary to develop a robust, reasonably accurate well specification. It will be argued that many of the critical considerations are insufficiently defined today and therefore merit additional investigation outside of this report. This EGS systems level analysis will require collaboration between all EGS subject matter experts in order to identify interactions between different EGS components that are likely to influence subsurface installations and operational processes.

A baseline well specification will then be provided in the context of current thinking within the EGS research community. The specification is founded on recommendations in the MIT Report. This well specification is based on a target output of 5 MWe from 80 kg/s, 200°C well head fluid produced from a depth of 6 km (~20,000 ft). It is meant to represent a modest incremental advance beyond current geothermal hydrothermal practices, where wells rarely exceed 3 km in depth, and serves as a starting point for appreciating how simple EGS wells may differ from those currently developed in the geothermal industry.

A task, time and cost based description of the well construction process for the baseline well specification is performed for this well construction technology evaluation by a leading geothermal drilling contractor, Thermasource Inc. The Thermasource effort represents a "drilling on paper" exercise intended to provide a detailed account of how the well of interest might be constructed using today's technologies. The governing assumption of the exercise is that all construction steps must employ existing tools and practices. Much of the envisioned well construction description draws on proven deep gas well practice because of the absence of geothermal experience at the depths of interest. It provides both a script of the daily, sequential tasks used to build the well and accounting of the tools used to perform those tasks. Rental, service and consumable cost estimates are also provided in order to assess total well cost.

The Thermasource well construction script is then subjected to an analysis in which all steps are described using a set of repetitive work elements. Distinct work elements, times and costs are summed in order to evaluate the relative importance of each element with respect to the well construction process as a whole. By logically decomposing the process in this manner a more manageable method for identifying where time and money are spent is achieved. The execution of each work element is dependent on the specific technology and operating process employed. Potential improvements for the well construction process are then outlined in terms of the technologies or operational processes needed to improve the relevant work elements.

The remainder of the report focuses on defining proposed thrusts for well construction technology R&D and providing more detailed descriptions of some of the technologies of interest. Research recommendations are grouped in three categories:

1. Systems Analysis - Investigation of interdependent EGS components for the purpose of developing a more refined and accurate understanding of well construction needs.
2. Enabling Technologies – Technologies or components that are generally believed to be important in future EGS applications, but whose exact purpose or use are not currently well defined.
3. Target Technologies – Technologies with well defined purposes that have been selected through systematic analysis of the well construction process.

Category 1 and 2 R&D recommendations will be offered without rigorous justification. In general they embody consensus investigation subjects frequently noted in EGS publications and workshops. Their relevance will be discussed primarily in relation to EGS well construction. Category 3 recommendations are mostly put forth based on the case study and analysis presented in this report.

Finally, it is noted that the analysis within this report was presented at a DOE sponsored EGS well construction technology evaluation workshop attended by well construction experts from the geothermal industry, oil & gas industry and national laboratory complex. The R&D recommendations within this report reflect a combination of prior investigation and feedback received at the workshop.

2 Well construction considerations and baseline well specification

The definition of EGS continuously evolves as it approaches proof of concept and commercial demonstration. In some instances it has been defined by what it is not. The MIT Report considers EGS "to include all geothermal resources that are currently not in commercial production and require stimulation or enhancement". This is an extension of the previously narrower U.S. Department of Energy definition of "Enhanced (or engineered) Geothermal Systems (EGS) as engineered reservoirs that have been created to extract economical amounts of heat from low permeability and/or porosity geothermal resources".

Regardless of the precise definition of EGS, it is likely that EGS wells may be substantially different in many respects from hydrothermal wells. Well construction disparities may occur because of differences in the geological structure of the EGS reservoir, reservoir manipulation procedures, and geothermal fluid production practices and procedures. A small subset of the factors that may influence EGS well design and construction are:

- Resource depth
- Influence of lithological variation on drilling
- Influence of lithological variation on well completion
- Influence of lithological variation on stimulation
- In-situ stress state influence on stimulation
- Presence of natural fracture features
- Stimulation methodology used to create reservoir volume and surface area
- Production strategy
- Intervention strategy

The remainder of this section will discuss a few of the factors that can affect future EGS well construction practices and illustrate the difficulty of constraining expected well specifications at the current stage of EGS development.

2.1 Resource depth

Commercial hydrothermal well depths in the United States range from shallow applications less than 1 km to approximately 4 km in a few cases. The MIT Report presents a variety of plots showing temperature at depth underlying the surface of the United States. These plots indicate that the vast majority of thermal resource lies in sedimentary and basement rocks well below 4 km in depth. The report does recommend that short term development focus on shallower high grade resources. However, if the long term objective is to extract heat from deeper resources then it will be necessary to significantly extend drilling requirements beyond current practice. Extending well depth can add significant complexity to drilling operations and well design. Drilling difficulties may include longer drilling at high temperature, greater formation variability, high formation fluid pressure, borehole integrity issues, and greater challenges controlling rock reduction and borehole trajectory. Greater depths also tend to increase well design complexity because more and larger casing intervals are required to successfully reach terminal depth as a result of the telescoping effect. Successfully projecting well construction technology needs will require a better understanding of future EGS application depths.

2.2 Lithological variation

Typical geothermal reservoirs are often monolithic as opposed to the layered varieties encountered in oil and gas applications due to the unique conditions required to form hydrothermal reservoirs[1]. The rock drilled is often hard and abrasive and sometimes is encountered from surface down to terminal depth. Accessing the vast sedimentary and basement rock thermal resource will significantly increase the variability of lithology encountered. In many instances EGS drilling may be more favorable than typical hydrothermal drilling because a significant fraction of easier-to-drill overlying rock may be encountered en route to the EGS reservoir. This lithological variability will however increase the difficulty of understanding programmatic well construction needs by increasing the range of drilling conditions encountered and well completion possibilities.

2.3 Reservoir creation

There are many unknowns related to reservoir creation with the potential to affect EGS well construction. At the heart of these unknowns is the manner in which the requisite quantity of surface area will be created in the volume of rock from which heat is to be recovered. An order of magnitude estimate of the rock volume required can be obtained by equating the heat flow rate from the reservoir (extracted heat) with the change in stored thermal energy in the reservoir assuming uniform extraction of heat from the volume[2]. The heat flow rate is then given as

$$Q = \rho C V \frac{dT}{dt} \qquad \textbf{2-1}$$

where
Q = heat flow rate
C = rock heat capacity
V = rock volume
T = rock temperature
ρ = density.

Assuming a spherical rock volume, the thermal heat flow rate per unit change in rock volume temperature in degrees C then becomes

$$\frac{Q}{\Delta T} = \frac{4\pi\rho C R^3}{3\Delta t} \qquad \textbf{2-2}$$

For granite properties (C=840 kJ/kgC, ρ=2600 kg/m3) and a 30 year thermal extraction period, Figure 2-1 below shows the heat flow rate per degree C change in rock temperature as a function of reservoir volume.

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[1] DOE sponsored EGS reservoir creation workshop, August 21, 2007, Houston, TX.
[2] Norm Warpinski, "Enhanced Geothermal Systems", Internal memo, Sandia National Laboratories

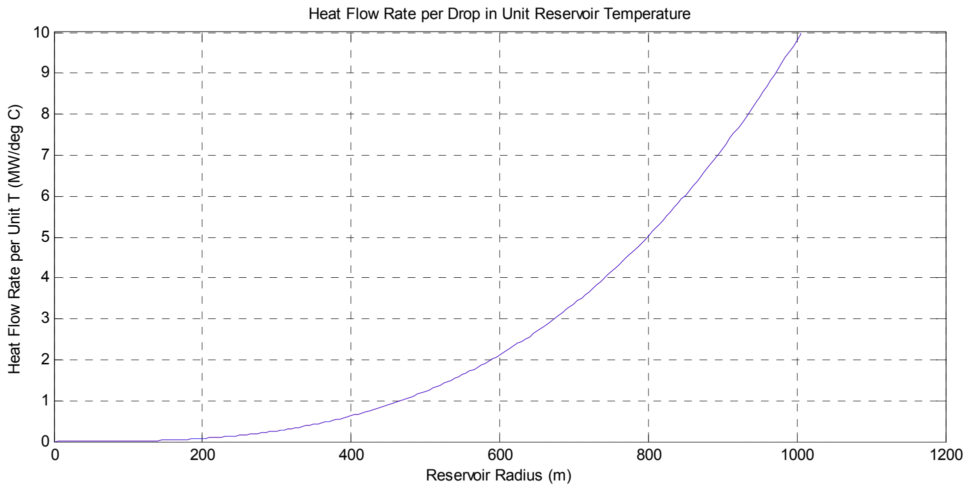

Figure 2-1 Heat flow rate per drop in unit reservoir temperature

If a 15% thermal to electric conversion efficiency is assumed then approximately 33 MW thermal heat flow rate will be needed to produce 5 MWe. If a 30°C drop in reservoir temperature is assumed then a reservoir radius of approximately 500 m and volume of 0.5 km^3 is required.

A recent, more rigorous assessment of EGS power generation prospects using numerical simulation studies[3] suggests that the electrical power generation rate achievable on a unit rock volume basis is 26 MWe/km^3. This power production correlation requires a volume of roughly 0.19 km^3 to generate 5 MWe, which is equivalent to a cube measuring 575 m on a side, but is based on the assumption of uniform properties within the stimulated region (including permeability). The Sanyal and Butler study evaluated well arrangements ranging from doublets (single production and single injector wells) to 5-spots (four producers and one injector). It concluded that if production of the reservoir is controlled so as to maintain a flat production rate, then generation capacity is primarily a function of stimulated rock volume with geometry being of secondary importance.

Though the geometry of the stimulated rock volume may be of secondary importance with respect to generation capacity, it is of primary importance with respect to how the well is stimulated to produce the EGS reservoir. This is so because the shape of stimulated volume will be related to the well configuration (geometry) in addition to other factors such as the number of wells used within a volume, the reservoir mechanical properties, the reservoir stress state and natural fracture features present in the production interval. These characteristics will collectively determine how the reservoir is best artificially manipulated to produce the necessary stimulated volume.

Reservoir stimulation of EGS will occur by hydraulic stimulation. Whether fracturing of the rock occurs by shear destabilization of natural fractures or by extensional failure of weaker zones, it is likely that a preferred arrangement of fractures and some control of

[3] Sanyal, S. K. and S. J. Butler. 2005. “An Analysis of Power Generation Prospects from Enhanced Geothermal Systems.” *Geothermal Resources Council Transactions*, 29.

the fracture process will be required to create the flow paths necessary for effective heat extraction. Even the simple doublet arrangement has numerous possible configurations if a fixed number of fractures are used to generate the desired stimulated rock volume. Armstead and Tester, for instance, show that for eight fractures, a total of 125,000 m^2 of surface area is able to maintain a production rate of 50 kg/s at 200°C[4]. The length of the production interval for a doublet with eight distinct fractures can vary significantly depending on the orientation of the fracture plane and the spacing between fracture zones.

For the sake of argument, assume only that the fracture plane has a vertical orientation. If mostly vertical production and injection wells are used, then the length of the production interval will be a function of the height of each fracture and the spacing between the eight fractures. If mostly horizontal wells are used and vertical fracturing occurs, then the overall length of the production interval can be considerably shorter because it will be limited only by the fracture spacing. Furthermore, if there is limited communication between the separate fractures then some well configurations will simplify the task of drilling a wellbore that intersects the fractures created by the stimulation. In the vertical well arrangement with vertical fractures, the narrow width of the fractures creates a narrow window through which the intersecting wellbore must be drilled. The horizontal well arrangement with vertical fractures by contrast creates a much larger drilling window (refer to Figure 2-2).

Creation of these eight fractures will presumably involve some selective placement strategy along the production interval of the wellbore in order to control issues such as communication between fractures and injection loss to the formation. Selective stimulation of zones is generally a sequential process. In some instances it can be accomplished in a relatively low-tech manner. Staged fracturing in which the well is "bull-headed" or stimulated from the wellhead is one example of a simple selective stimulation technique that creates zones from the bottom of the well upwards. Lower zones are fractured leaving proppant in the hole, often referred to as a sand plug, above the stimulated zone to permit fracturing of the next overlying zone in an upward progression. The use of straddle packers while pumping through tubing is a more technologically complex method for which more specialized tools and procedures are required. Casing is often required over the production interval for this method if retrievable tools are to be used. Multi-stage fracturing processes involving specialized packer systems and permanent well completion systems consisting of production tubing separated by production packers with anchor seals or polished bore receptacles are even more complex, but more versatile selective stimulation methods. <u>Thus it evident that the stimulation methodology employed can significantly influence the well completion.</u>

[4] Armstead, H.C.H. and Tester, J.W., *Heat Mining*, E. & R.N. Spon, London, 1987.

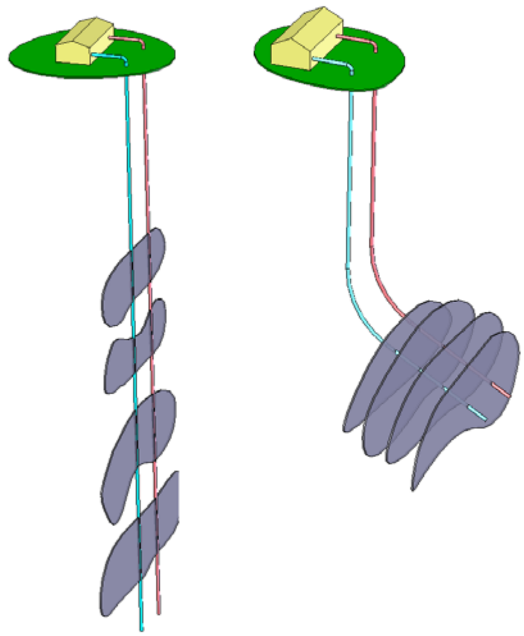

Figure 2-2 Vertical and deviated well arrangements with vertically oriented fractures

2.4 Reservoir Production

In many respects EGS may be more like enhanced oil production than conventional hydrothermal geothermal production. Hydrothermal wells generally possess open-hole or slotted liner completions for which there is no zonal isolation along the production interval. This type of completion is possible because of the high permeability, high transmissivity and convective nature of hydrothermal reservoirs and the relative unimportance of communication between zones. EGS by contrast is likely to more closely approximate a closed loop type of flow system with more direct flow paths from injection to producing wells. The production of EGS reservoirs may therefore be more influenced by the path taken by the fluid from injection to production wells.

This concern is reflective of water and steam flooding operations in the oil and gas industry. In these applications water or steam is injected into the formation to displace oil from injection to production wells. If the path of injected fluid is not properly controlled, "breakthrough" or the equivalent of short circuiting occurs in which injected fluid takes a more direct path between injector and producer resulting in ineffective sweeping of the oil in place. Specialized completions are often used in operations of this nature to better control zonal injection. These completions primarily serve to selectively choke or restrict individual zones to more evenly distribute injected fluid into the formation or they can provide the capability to isolate breakthrough prone zones. If this type of injection control is desired for EGS then the use of more complex completions, as opposed to open hole or slotted liners, will certainly be required and will significantly influence well construction specifications and technology.

2.5 Reservoir Intervention

It is likely that at some point over the course of the EGS well life cycle some form of intervention will be required. Injected fluid loss, short circuiting or scale-induced flow restriction of individual zones are potential problems whose remedy may involve intervention operations. The selective treatment of a zone may be more cost and functionally effective if the well completion in place permits the use of a more technologically effective method. This again will require a departure from the simple completions characteristic of hydrothermal wells and must be factored into the EGS well construction process during the design stage. In more extreme cases it may even be necessary to re-drill the completion interval. A better grasp of the objectives and prospective processes to be used is required in order to better integrate intervention strategies with EGS well construction practice.

2.6 Section Summary

The previous subsections provide discussion of issues that may affect EGS well construction. In simplest terms, each of the considerations described has the ability to influence one or more of the factors listed below that can affect well construction technology or the well construction process:

- Required drilling tools
- Preferred drilling practice
- Well trajectory
- Well branching (monobore versus multilateral)
- The number of casing strings and casing diameters required (telescoping effect)
- Well completion

3 Baseline Well Specification

The specification for the baseline EGS well to be analyzed in this report is shown below in Figure 3-1. As mentioned in Section 2.1, the 6 km (~20k ft) terminal vertical depth (TVD) is significantly greater than what is currently drilled within the commercial geothermal industry where wells rarely exceed 3 km. This profile has been selected to represent the simplest departure from current geothermal practice with the potential to tap a modest amount of 200°C source rock[5]. The remainder of this section will present discussion and calculations demonstrating preliminary indication of the feasibility of this well profile to generate the fluid production rates at temperature referenced as necessary for EGS economic viability in the MIT Report.

3.1 EGS Artificial Lift Preliminary Considerations

The MIT panel in the "Future of Geothermal Energy" noted that it is critical to develop a production flow rate of 80 kg/sec at 200°C well head temperature to make EGS systems viable. The calculations presented in this section are used to provide a first order estimate of the ability of the well depicted in Figure 3-1 to meet this production flow specification with and without artificial lift.

Currently demonstrated flows of approximately 20 kg/sec have been achieved at Soultz at a productivity index (PI) of about 0.04 kg/sec/psi.[6] Two ways of increasing well flow are to improve the stimulation of the well (increase the PI) and to increase the pressure across the reservoir. The pressure at the inflow to the reservoir (injection well) must be limited to prevent unwanted growth of the reservoir and leakage of fluid out of the reservoir. This pressure has already been "maximized" at Soultz and other EGS projects. Artificial lift in the injection well (lowering the pressure of the outflow from the reservoir into the production well) has not been "maximized."

Two kinds of artificial lift are applicable to geothermal systems: line shaft pumps and electrical submersible pumps (ESP). Line shaft pumps work at lower flow rates and pump set depths than ESPs. Thus ESPs have higher potential for aiding in reaching EGS economic flow rates.

In order to use an ESP the diameter of the well must accommodate the pump. Thus the need for well construction specifications that allow for acceptable artificial lift. Acceptable artificial lift is assumed in this study to place a parasitic load on the system that is no greater than 20%. An EGS system will further benefit from artificial lift (exceed acceptable requirements) if the extractable energy content of the additional flow is proportionately greater than the parasitic load of the pumps. For example, if the parasitic load of the pumps is 20% of the output of the system and the increase in the flow associated with the pump contributes more than 20% to the useable system energy. Assuming this condition is met, it is advantageous to use as big an ESP as practical.

[5] MIT Report, Figure 2.8b
[6] IGA News N0. 71, January-March 2008.

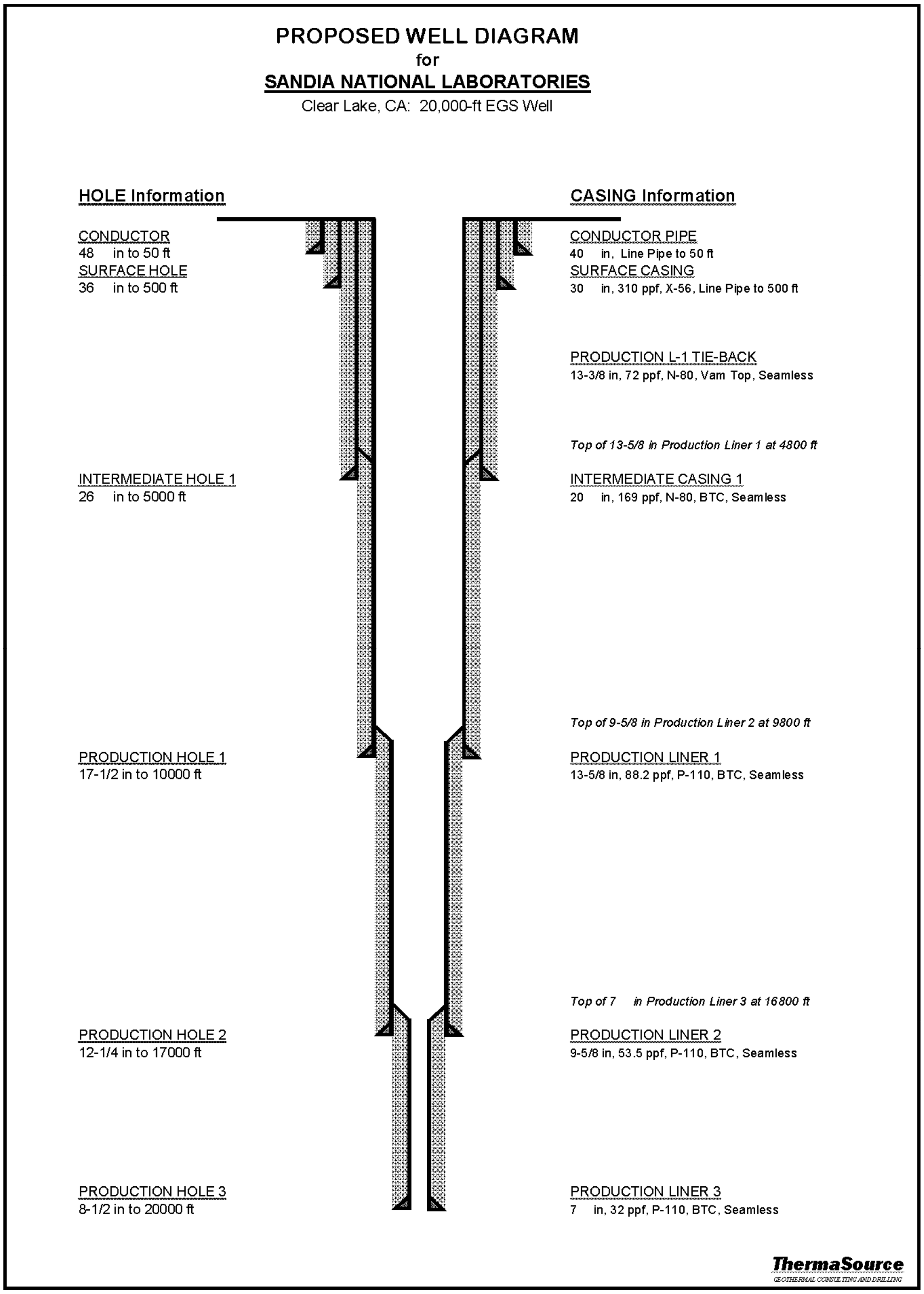

Figure 3-1 Baseline well schematic

The artificial lift system places a variety of constraints on the specifications of well construction including:

- Wellhead configuration
- Trajectory of the well (assumed vertical in this case)
- Diameter of the well to pump set depth (assumed to be 13 3/8” casing in this case).

The pump set depth determines the maximum allowable lift at a given flow rate given the available power. Exceeding maximum allowable lift (using too big an ESP at too shallow a pump set depth) will cause the fluid to boil at the pump inlet damaging the pump.

ESPs have been demonstrated in geothermal applications[7]; however, they are not considered proven technology. In other words, the limitations of ESPs are not known for long term geothermal applications. High temperature (~215°C in steam flooding) and high flow rates (~86 kg/sec in off-shore) have been achieved in oil field operations, but these have not been done simultaneously. Furthermore, geothermal applications introduce additional design considerations over oil field operations:

- Thermal cycling destroys ESP motor insulation
- Back-spin damages ESPs in hydrothermal applications (the higher viscosity of oil in oil field applications makes back-spin less of an issue)
- Scaling and corrosion are aggravated by high temperature and geothermal brines
- Simultaneous high pressure differential and flow requires additional horse power which results in extra heat generation in the motor and extra load on components
- Water is a better cooling fluid than oil, so ESP motors won’t require as much de-rating for geothermal applications (~290°C →215°C for SAGD)
- Larger bowls increase reliability
- Multi-stages reduce reliability

3.2 Well Flow Capacity

While ESP manufacturers publish specifications implying EGS suitable ESPs can be set in well diameters as small as 8 5/8”, current best practices for geothermal applications would be to use 13 3/8” casing.

Since the considered well design meets the trajectory and diameter at pump set depth (vertical and 13 3/8”) noted above, two primary questions arise:

1. Does the well have adequate flow capacity?
2. What benefit can be obtained with current ESPs capabilities?

To address these questions a set of calculations have been made using the following assumptions:

- Elevation: insufficient to impact performance of system,

[7] William C. Price and Lawrence Burleigh, “Electrical Submersible Pumps for Geothermal Resources”, *Geothermal Resources Council Transactions*, Vol. 25, August 26-29, 2001.

- Well type: vertical: 20,000 ft
- PI: 0.04 kg/sec/psi (Soultz average),
- Formation temperature & pressure: 200°C & hydrostatic,
- Pump set depth: 4000 ft, and
- Completion interval: 17,000 ft to 20,000 ft.

Target performance is 80 kg/sec using less than 20% of an assumed 6.5 MWe output generated from a doublet well pair (a triplet would be a refinement of these calculations and may allow some additional control over reservoir performance). Temperature change along the injection and production wells (that is heat loss or gain) is not considered. Heat loss should not be large enough to affect conclusions drawn as a result of these calculations.

A functional well design must not only have adequate space for the ESP, it must also not choke well flow by providing too much frictional resistance to flow. Frictional head loss increases proportional to the inverse fifth power of well diameter ($\sim/d^5$). Figure 3-2 shows the pressure loss per 1,000 ft as a function of diameter for 200°C liquid water flowing at 80 kg/sec through rough pipe. The 6" ID corresponds to the liner in the completion interval. A liner length of 3,000 ft results in approximately 280 psi of head loss, which by comparison is about 30% of the head or buoyancy due to the contrast in produced and injected fluid density. Thus, the frictional resistance to flow through the completion interval liner is neither insignificant nor so large as to choke the flow. The impact of frictional pressure loss through the completion interval liner can therefore only be evaluated by modeling flow from the injection wellhead to the production wellhead.

Appendix A describes the approach used to model flow down the injection well, through the reservoir, and back up the production well. In summary the approach uses Bernoulli's equation and a Moody friction factor for flow in the casing and a PI for flow through the reservoir.

Using the parameters noted above, a flow of approximately 33 kg/sec is expected for a PI of 0.04 kg/sec/psi. This is better than Soultz performance indicating that the well design is appropriate for the assumed EGS resource (200°C at 20,000 ft with a hydrostatic reservoir gradient). Figure 3-3 shows the pressure profiles in the injector and producer for this case.

With an ESP the expected flow rate is approximately 77 kg/sec, close to the goal of 80 kg/sec. Thus, the combination of an ESP pump together with a correspondingly appropriate well design can significantly contribute to achieving the flow rate assumed necessary by the MIT panel. The ESP pump (and charge pump on the injector) more than doubles the flow rate while consuming only 20% of the electrical generation (based on an ESP efficiency of 75%). Figure 3-4 shows the pressure profiles in the injector and producer for this case. The balance between the injection well charge pump and ESP found to balance the pressure difference across the reservoir was 0.7 MWe for the ESP and 0.6 MWe for the charge pump. The shaft load between the ESP motor and pump is 700 hp and is within the capabilities of existing ESP motors, even at a de-rating factor of

50% for geothermal conditions. The pressure boost required from the ESP is approximately 825 psi.

Note: By balancing the pressure difference across the reservoir it is meant that the pressure at the bottom of the injector over hydrostatic was the same as the pressure at the bottom of the producer under hydrostatic. These pressure differences are adjustable when there is both an ESP and a charge pump. "Balancing" these pressures gives a degree of control of water leakage out of the reservoir. Too much over pressure in the injector can result in unintended growth of the reservoir requiring additional water and may contribute to short circuiting.

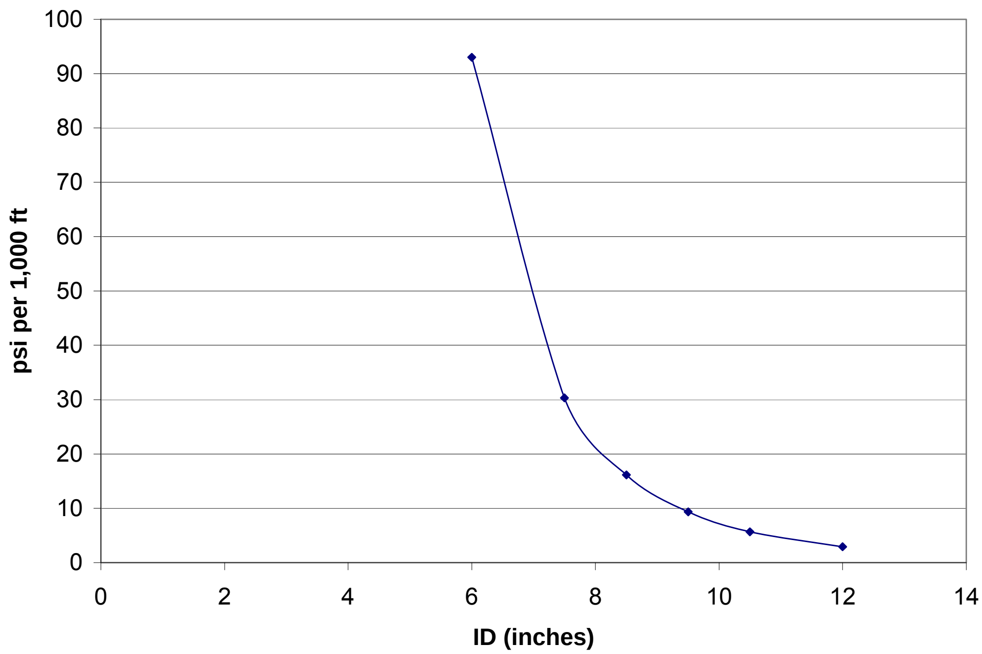

Figure 3-2 Pressure loss per 1,000 ft as a function of diameter for 200°C liquid water

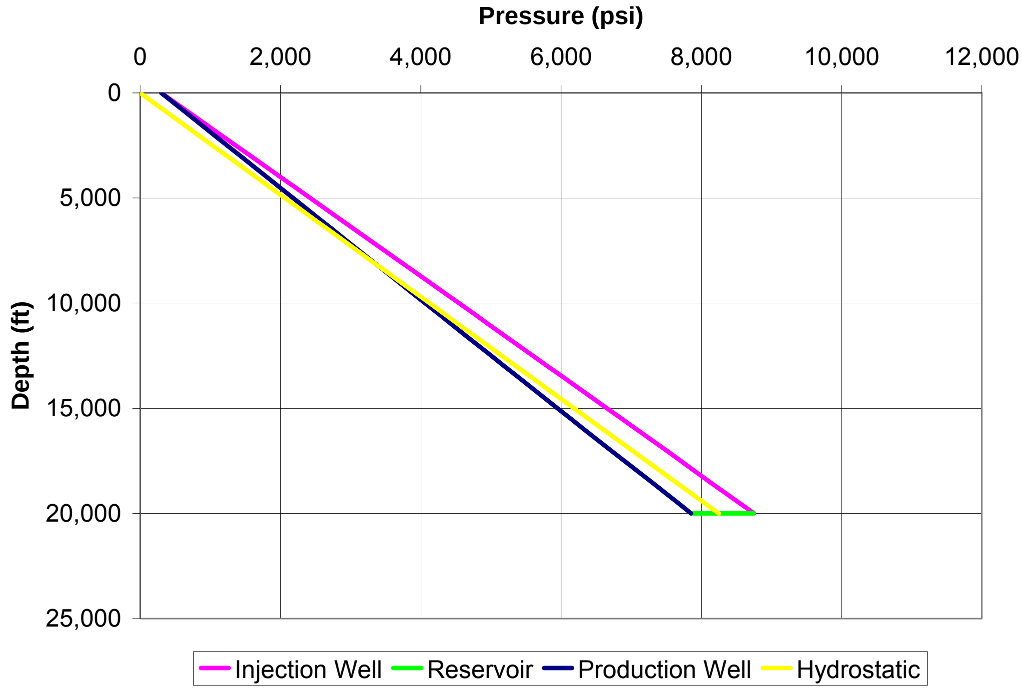

Figure 3-3 Pressure profiles with no ESP

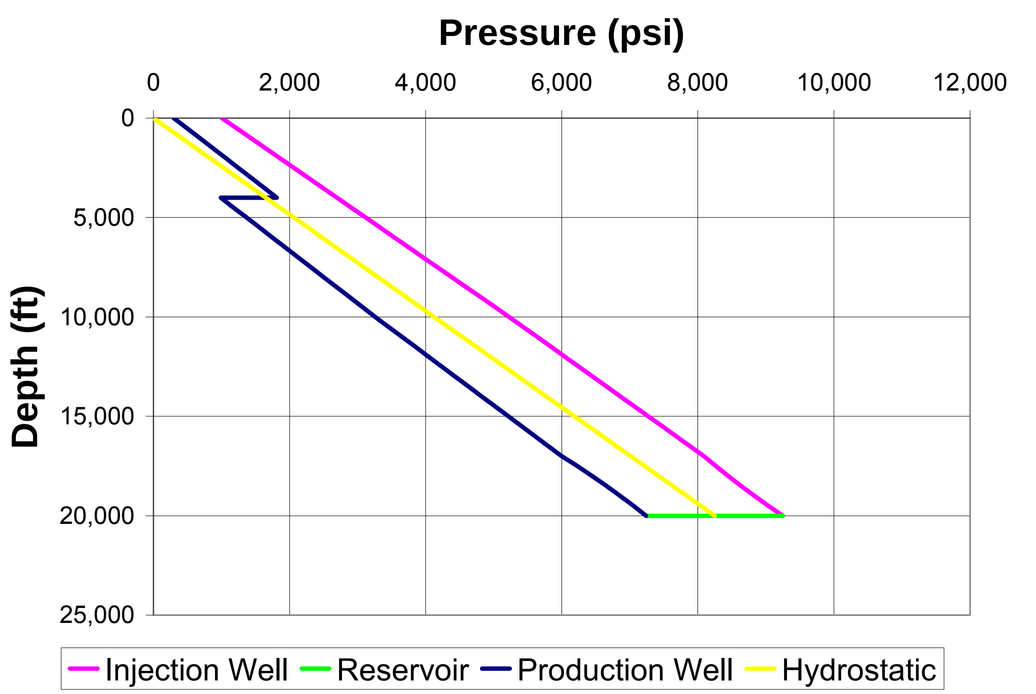

Figure 3-4 Pressure profiles with an ESP and injection well charge pump

4 Well Construction Case Study

Thermasource Inc., a premier geothermal consulting and drilling company, was commissioned to perform a "drilling on paper" exercise in which the tools, tasks and times required to construct the baseline well specification were explicitly defined in sequential order. Operations in most instances are parsed to an hourly level. This resolution of description in the drilling script is intended to depict the effort associated with utilizing distinct technologies and processes so as to more easily identify improvement opportunities.

This "bottom up" definition of the well construction sequence was complemented by lumped time and cost estimates for completing each interval. Lumped estimates were based on Thermasource field experiences and discussions with other industry experts with deep gas well experience. Bottom up and top down time estimates were iteratively compared and modified to settle upon what Thermasource considered to be a reasonable drilling scenario.

Many of the assumptions used in the analysis are presented in Appendix B. It is important to note that the particular case planned does not incorporate mobilization and demobilization costs, site preparation costs, trouble time and does not assume a specific lithology profile. Drilling related parameters and performance are instead assumed based on experience in the general area in which the well is to be drilled. It is recognized in this report that future well construction analysis should focus on specific locations and lithologies based on near and longer term implementation strategies for EGS.

The presented well construction case is in some respects conservative and others moderate. Assumed drilling rates for example are reflective of favorable conventional geothermal situations. It is highly plausible that future EGS locations can be selected for which a large extent of less hard and abrasive rock overlies the low permeability zone of interest in order to improve drilling rates. On the other hand, as stated above, no non-productive time (NPT) is assumed in this analysis. NPT in many instances is caused by wellbore integrity issues, lost circulation, formation pressure problems and poor drilling control (stuck pipe, trajectory control, etc.). These causes of NPT tend to be formation related and therefore require a more precise definition of the geology to be drilled. Evaluation of NPT related influence on well construction technology and practice will be left to future investigation.

The remainder of this section will consist of the summary documentation provided by Thermasource.

The well design produced by Thermasource is shown in the following sub-section and drilling operations are divided into these six phases:

- PHASE (I): SURFACE: (36" Hole to 500' with 30" Casing)
- PHASE (II): INTERMEDIATE 1: (26" Hole to 5000' with 20" Casing)
- PHASE (III): PRODUCTION LINER 1: (17-1/2" Hole to 10,000' with 13-5/8" Casing)
- PHASE (IV): PRODUCTION LINER 2: (12-1/4" Hole to 17,000' with 9-5/8" Casing)

- <u>PHASE (V): PRODUCTION LINER 3: (8-1/2” Hole to 20,000’ with 7” Casing)</u>
- <u>PHASE (VI): PRODUCTION TIEBACK: (13-3/8” Casing)</u>

A detailed description of well parameters, drilling performance, and the step-by-step drilling script is given in Appendix B.

A summary of the costs and times for the six phases is given in the following section.

4.1 Lumped time and cost estimates

ThermaSource
GEOTHERMAL CONSULTING AND DRILLING
3883 Airway Drive
Suite 340
Santa Rosa, CA 95403
TELEPHONE: (707) 523-2960

GENERAL INPUT FOR CASING AND HOLE DETAILS

NAME OF OPERATOR: SANDIA NATIONAL LABORATORIES
FIELD NAME: Clear Lake, CA
Well Name: 20,000-ft EGS Well
Estimator / Engineer: Robert J. Swanson
Date: August 13, 2008

Well Schematic ID: EGS-20000

WELL STRING DETAILS	Used Y or N	Cemented or Slotted	CASING DETAILS										HOLE DETAILS	
			OD (in)	Weight (ppf)	Grade	Connection	Mftg Process	Nom ID (in)	API Drift Diameter	Special Drift ✓	Pipe Length	Lap Length (ft)	Size (in)	Depth (ft)
Conductor Pipe	Y	Cemented	40			Welded	Line Pipe	38.000	38.000		50		48	50
Surface Casing	Y	Cemented	30	310.0	X-56	Dril Quip	Line Pipe	28.000	28.000		500		36	500
Intermediate Casing 1	Y	Cemented	20	169.0	N-80	BTC	Seamless	18.376	18.188		5000		26	5,000
Intermediate Casing 2	N	Cemented									0			
Intermediate C-2 Tie-Back	N	Cemented												
Production Liner 1	Y	Cemented	13-5/8	88.2	P-110	BTC	Seamless	12.375	12.250		5200	200	17-1/2	10,000
Production L-1 Tie-Back	Y	Cemented	13-3/8	72.0	N-80	Vam Top	Seamless	12.347	12.191	Required	4800			
Production Liner 2	Y	Cemented	9-5/8	53.5	P-110	BTC	Seamless	8.535	8.379	Required	7200	200	12-1/4	17,000
Production Liner 3	Y	Cemented	7	32.0	P-110	BTC	Seamless	6.094	5.969	Required	3200	200	8-1/2	20,000
Production Liner 4	N												6	

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Figure 4-1 Case study well details

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GENERAL INPUT FOR PLANNED DAYS and PLANNED COST vs DEPTH CURVE

Sort Activities | Reset

OK: Cost Allocation Matches Total Estimated Cost

DVD Plot Options: T — Days from Spud = S; Total Days = T	Order of Activities # or "NA"	Hole Depth (ft)	Drill Distance (ft)	Est Ft/Day	Days 92 143	Cost No MobCost $'000
A) Rig Move	1				0	20
B) Drill Surface Hole	2	500	450	110	4	456
C) SF Casing Operations	3				4	660
D) Drill Intermediate Casing 1	4	5,000	4,500	275	16	1,916
E) IC1 Casing Operations	5				7	2,655
I) Drill Production Liner 1	6	10,000	5,000	275	18	1,867
J) PL1 Casing Operations	7				8	2,506
L) Drill Production Liner 2	8	17,000	7,000	205	34	3,293
M) PL2 Casing Operations	9				9	1,985
N) Drill Production Liner 3	10	20,000	3,000	150	20	1,876
O) PL3 Casing Operations	11				14	1,617
K) PL1TB Casing Operations	12				9	2,403
R) Completion Operations	13				0	-
F) Drill Intermediate Casing 2	NA				0	-
G) IC2 Casing Operations	NA					-
H) IC2TB Casing Operations	NA					-
P) Drill Production Liner 4	NA				0	-
Q) PL4 Casing Operations	NA					-

SANDIA NATIONAL LABORATORIES
20,000-ft EGS Well

	Cost	Days	Depth
	0	0	0
A) Rig Move	20	0	0
B) Drill Surface Hole	476	4	500
C) SF Casing Operations	1,136	8	500
D) Drill Intermediate Casing 1	3,052	24	5,000
E) IC1 Casing Operations	5,707	31	5,000
I) Drill Production Liner 1	7,573	49	10,000
J) PL1 Casing Operations	10,079	57	10,000
L) Drill Production Liner 2	13,373	91	17,000
M) PL2 Casing Operations	15,358	100	17,000
N) Drill Production Liner 3	17,234	120	20,000
O) PL3 Casing Operations	18,851	134	20,000
K) PL1TB Casing Operations	21,254	143	20,000
R) Completion Operations	21,254	143	20,000
	21,254	143	20,000
	21,254	143	20,000
	21,254	143	20,000
	21,254	143	20,000
	21,254	143	20,000

Date Printed: 8/21/2008 — General Input

Figure 4-2 Drilling overview

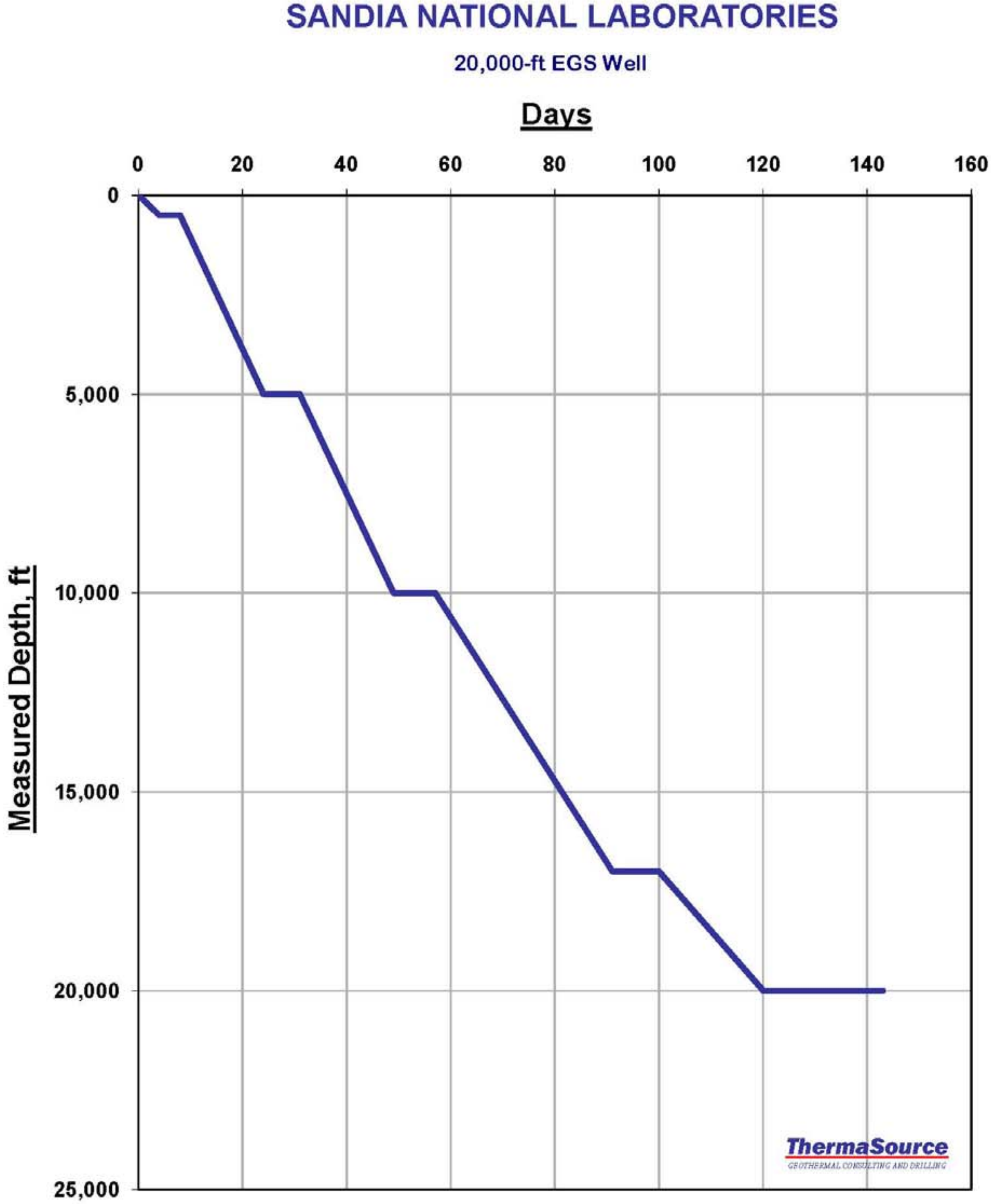

Figure 4-3 Depth versus days plot

Figure 4-4 Cost estimation spreadsheet (following three pages)

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Estimator / Engineer: Robert J. Swanson
August 13, 2008
OK: Cost Allocation Matches Total Estimated Cost

COST ESTIMATING DATA INPUT TABLE

SANDIA NATIONAL LABORATORIES
Clear Lake, CA
20,000-ft EGS Well

TOTAL ESTIMATED DAYS: 143
DRILLING DAYS: 92

ROUNDED-UP TOTAL COST $ 21,340,000

Acctng Code	COST CATEGORIES			Units	Quantity	Unit Cost	Total Est Cost $ 21,254,091
	EQUIPMENT RENTAL AND SERVICES					$	15,745,691
10	**RIG MOBILIZATION and DEMOBILIZATION**						$ -
	Mobilization			$	1	-	-
	Demobilization			$	1	-	-
20	**CONTRACT DRILLING RIG**						$ 6,224,075
	Rig Move Day Rate			$/day	0		-
	Trucks and Cranes for Rig Move			$	0		-
	Rig Operating Day Rate			$/day	143	28,000.00	4,004,000
	Top Drive Rental			$/day	143	3,200.00	457,600
	Rig Welding Services			$/day	143	700.00	100,100
	Fuel			gal/day	2,500	4.25	1,519,375
	Rig Crew Travel and Accommodations			$/day	143	1,000.00	143,000
30	**PLANNING, ENGINEERING AND PROJECT MANAGEMENT**						$ 747,000
	Rig Site Management			$/day	143	2,000.00	286,000
	Engineering Services			$/day	143	2,000.00	286,000
	Project Management			$/month	6	25,000.00	150,000
	Well Insurance			$	1	25,000.00	25,000
40	**DRILLING FLUIDS AND SOLIDS CONTROL**						$ 1,057,916
	Drilling Fluids Engineer			$/day	143	900.00	128,700
	Drilling Fluid Materials	Status	Size				
	Surface Hole	Y	*36 in*	$/bbl	2,645	7.00	18,515
	Intermediate Hole 1	Y	*26 in*	$/bbl	14,781	10.00	147,810
	Intermediate Hole 2	N		$/bbl			-
	Production Hole 1	Y	*17-1/2 in*	$/bbl	7,440	14.75	109,740
	Production Hole 2	Y	*12-1/4 in*	$/bbl	5,104	21.15	107,950
	Production Hole 3	Y	*8-1/2 in*	$/bbl	1,053	25.50	26,852
	Production Hole 4	N		$/bbl			-
	Shakers, Mud Cleaner and Centrifuge Rental			$/day	143	1,200.00	171,600
	Shaker Screens			$	50	500.00	25,000
	Mud Cooler Rental			$/day	143	750.00	107,250
	Sumpless Drilling and Cuttings Management Services			$/day	143	1,500.00	214,500
50	**DIRECTIONAL DRILLING SERVICES**						$ 1,392,000
	Directional Drilling Equipment			$/day	92	12,000.00	1,104,000
	Directional Drilling Personnel			$/day	144	2,000.00	288,000
60	**CEMENT and SERVICES**	**Status**	**Cemented**				$ 3,671,900
	Surface Casing	Y	Cemented	$/bbl	350	630.00	220,500
	Intermediate Casing 1	Y	Cemented	$/bbl	2,030	595.00	1,207,850
	Intermediate Casing 2	N	Cemented	$/bbl			-
	Intermediate C-2 Tie-Back	N	Cemented	$/bbl			-
	Production Liner 1	Y	Cemented	$/bbl	940	760.00	714,400
	Production L-1 Tie-Back	Y	Cemented	$/bbl	970	660.00	640,200
	Production Liner 2	Y	Cemented	$/bbl	600	920.00	552,000
	Production Liner 3	Y	Cemented	$/bbl	115	2,930.00	336,950
	Production Liner 4	N	0	$/bbl			-
70	**AIR DRILLING SERVICES**						$ 527,500
	Air Compressor Standby Day Rate			$/day	75	1,500.00	112,500
	Air Compressor Operating Day Rate			$/day	68	2,500.00	170,000
	Air Compressor Personnel			$/day	68	1,500.00	102,000
	Air Drilling Flow Line and Separator System Rental			$/day	143	1,000.00	143,000

Date Printed: 8/21/2008 Cost Data Input

ThermaSource
GEOTHERMAL CONSULTING AND DRILLING

Estimator / Engineer: Robert J. Swanson
August 13, 2008
OK: Cost Allocation Matches Total Estimated Cost

COST ESTIMATING DATA INPUT TABLE

SANDIA NATIONAL LABORATORIES
Clear Lake, CA
20,000-ft EGS Well

TOTAL ESTIMATED DAYS: 143
DRILLING DAYS: 92

ROUNDED-UP TOTAL COST $ 21,340,000

Acctng Code	COST CATEGORIES	Units	Quantity	Unit Cost	Total Est Cost $ 21,254,091
80	GEOLOGIC EVALUATION AND RESERVOIR ENGINEERING				$ 1,075,450
	Mud Logging Services	$/day	143	2,000.00	286,000
	H2S Monitoring, Testing and Training Services	$/day	143	750.00	107,250
	Wireline Services	$	5	125,000.00	625,000
	Coring Services	$/day			-
	Well Testing Services	$/day			-
	Geologic Services	$/day	143	400.00	57,200
90	DRILLING TOOLS RENTAL AND REPAIR				$ 473,200
	Stabilizers, Roller Reamers and Hole Openers Rental	$	92	900.00	82,800
	Rebuild Charges for Stabilizers, Roller Reamers and Hole Openers	$	1	50,000.00	50,000
	Jars, Intensifiers and Shock Subs Rental	$/day	92	800.00	73,600
	Rebuild Charges for Jars, Intensifiers and Shock Subs	$	1	40,000.00	40,000
	Drill Pipe, HWDP and Drill Collar Rental	$/day	92	150.00	13,800
	Drill Pipe Hard Banding and Repair	$	700	100.00	70,000
	Tubular Inspection Services	$/day	143	1,000.00	143,000
100	WELL CONTROL EQUIPMENT RENTAL AND SERVICES				$ 312,100
	BOP Rental	$/day	143	1,500.00	214,500
	BOP Inspection and Repair	$	3	10,000.00	30,000
	BOP Consumables	$	1	20,000.00	20,000
	Rotating Head Rental	$/day	86	350.00	30,100
	Rotating Head Rubbers	$	5	1,500.00	7,500
	Drill Pipe Floats	$	20	500.00	10,000
110	RIG SITE LOGISTICS				$ 164,450
	Communications	$/day	143	250.00	35,750
	Rig Monitoring System	$/day	143	250.00	35,750
	Rig Site Living Accommodations	$/day	143	500.00	71,500
	Potable Water and Power	$/day	143	150.00	21,450
120	ROAD AND LOCATION CONSTRUCTION				$ -
	Permits and Surveying	$	1	-	-
	Roads and Location Construction Costs	$	1	-	-
	Conductor and Cellar Installation	$	1	-	-
130	TRUCKING AND TRANSPORTATION				$ 100,100
	Equipment Transportation	$	143	500.00	71,500
	Vacuum Trucking	$			-
	Vehicle Rental	$/day	143	50.00	7,150
	Forklift and Man Lift Rental	$/day	143	150.00	21,450
140	COMPLETION SERVICES				$ -
	Perforating Services	$			-
	Stimulation Services	$			-
	Coiled Tubing Services	$			-
150	FISHING TOOLS AND SERVICES				$ -
	Daily Service	$/day			-
	Tool Rental	$/day			-
	Fishing Tool Repair	$			-

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GEOTHERMAL CONSULTING AND DRILLING

Estimator / Engineer: Robert J. Swanson
August 13, 2008
OK: Cost Allocation Matches Total Estimated Cost

COST ESTIMATING DATA INPUT TABLE

SANDIA NATIONAL LABORATORIES

Clear Lake, CA
20,000-ft EGS Well

TOTAL ESTIMATED DAYS: 143
DRILLING DAYS: 92

ROUNDED-UP TOTAL COST $ 21,340,000

Acctng Code	COST CATEGORIES			Units	Quantity	Unit Cost	Total Est Cost $ 21,254,091
	MATERIALS, CONSUMABLES AND RELATED SERVICES					$	**5,508,400**
160	**BITS**	**Status**	**Size**				**$ 784,000**
	Surface Hole	Y	36 in	$	1	80,000.00	80,000
	Intermediate Hole 1	Y	26 in	$	4	85,000.00	340,000
	Intermediate Hole 2	N		$			-
	Production Hole 1	Y	17-1/2 in	$	3	50,000.00	150,000
	Production Hole 2	Y	12-1/4 in	$	6	25,000.00	150,000
	Production Hole 3	Y	8-1/2 in	$	4	16,000.00	64,000
	Production Hole 4	N		$			-
170	**CASING AND TUBING**	**Status**	**Size**				**$ 4,364,400**
	Conductor Pipe	Y	40 in	$/ft	50	400.00	20,000
	Surface Casing	Y	30 in	$/ft	500	300.00	150,000
	Intermediate Casing 1	Y	20 in	$/ft	5,000	190.00	950,000
	Intermediate Casing 2	N		$/ft	0		-
	Intermediate C-2 Tie-Back	N		$/ft	0		-
	Production Liner 1	Y	13-5/8 in	$/ft	5,200	216.00	1,123,200
	Production L-1 Tie-Back	Y	13-3/8 in	$/ft	4,800	235.00	1,128,000
	Production Liner 2	Y	9-5/8 in	$/ft	7,200	98.00	705,600
	Production Liner 3	Y	7 in	$/ft	3,200	68.00	217,600
	Production Liner 4	N		$/ft	0		-
	Casing Crews and Lay Down Machine			$	7	10,000.00	70,000
180	**CASING ACCESSORIES**						**$ 187,000**
	Production Liner 1 Hanger and Running Services	Y		$	1	45,000.00	45,000
	Production Liner 2 Hanger and Running Services	Y		$	1	35,000.00	35,000
	Production Liner 3 Hanger and Running Services	Y		$	1	25,000.00	25,000
	Production Liner 4 Hanger and Running Services	N		$			-
	Liner Adapter	6	13,667	$			-
	Centralizers			$	1	25,000.00	25,000
	Float Shoes and Float Collars			$	1	57,000.00	57,000
190	**PRODUCTION EQUIPMENT**						**$ 173,000**
	Surface Casing Head			$	1	20,000.00	20,000
	Intermediate Casing Head			$	1	15,000.00	15,000
	Tieback Casing Head			$	1	10,000.00	10,000
	Expansion Spool			$			-
	Master Valves			$	2	35,000.00	70,000
	Wing Valves			$	3	4,000.00	12,000
	Nuts, Studs, Flanges and Gages			$	1	10,000.00	10,000
	Wellhead Welding and Installation Services	3	57,667	$	3	12,000.00	36,000
200	**NEW CATEGORY**						**$ -**
							-
							-
							-
							-
							-

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GEOTHERMAL CONSULTING AND DRILLING
3883 Airway Drive
Suite 340
Santa Rosa, CA 95403
TELEPHONE: (707) 523-2960

WELL COST ESTIMATE

NAME OF OPERATOR: **SANDIA NATIONAL LABORATORIES**
FIELD NAME: Clear Lake, CA
Well Name: 20,000-ft EGS Well
Estimated Number of Days: **143**

SUMMARY OF ESTIMATED COSTS

EQUIPMENT RENTAL AND SERVICES	$ 15,810,000
MATERIALS, CONSUMABLES AND RELATED SERVICES	$ 5,530,000
TOTAL DRILLING COST	**$ 21,340,000**

Code	COST CATEGORIES	Total Cost
	EQUIPMENT RENTAL AND SERVICES	$ 15,810,000
10	RIG MOBILIZATION and DEMOBILIZATION	-
20	CONTRACT DRILLING RIG	6,230,000
30	PLANNING, ENGINEERING AND PROJECT MANAGEMENT	750,000
40	DRILLING FLUIDS AND SOLIDS CONTROL	1,060,000
50	DIRECTIONAL DRILLING SERVICES	1,400,000
60	CEMENT and SERVICES	3,680,000
70	AIR DRILLING SERVICES	530,000
80	GEOLOGIC EVALUATION AND RESERVOIR ENGINEERING	1,080,000
90	DRILLING TOOLS RENTAL AND REPAIR	480,000
100	WELL CONTROL EQUIPMENT RENTAL AND SERVICES	320,000
110	RIG SITE LOGISTICS	170,000
120	ROAD AND LOCATION CONSTRUCTION	-
130	TRUCKING AND TRANSPORTATION	110,000
140	COMPLETION SERVICES	-
150	FISHING TOOLS AND SERVICES	-
	MATERIALS, CONSUMABLES AND RELATED SERVICES	$ 5,530,000
160	BITS	790,000
170	CASING AND TUBING	4,370,000
180	CASING ACCESSORIES	190,000
190	PRODUCTION EQUIPMENT	180,000
200	NEW CATEGORY	-

Date Printed: 8/21/2008 Cost Summary

Figure 4-5 Cost category summary

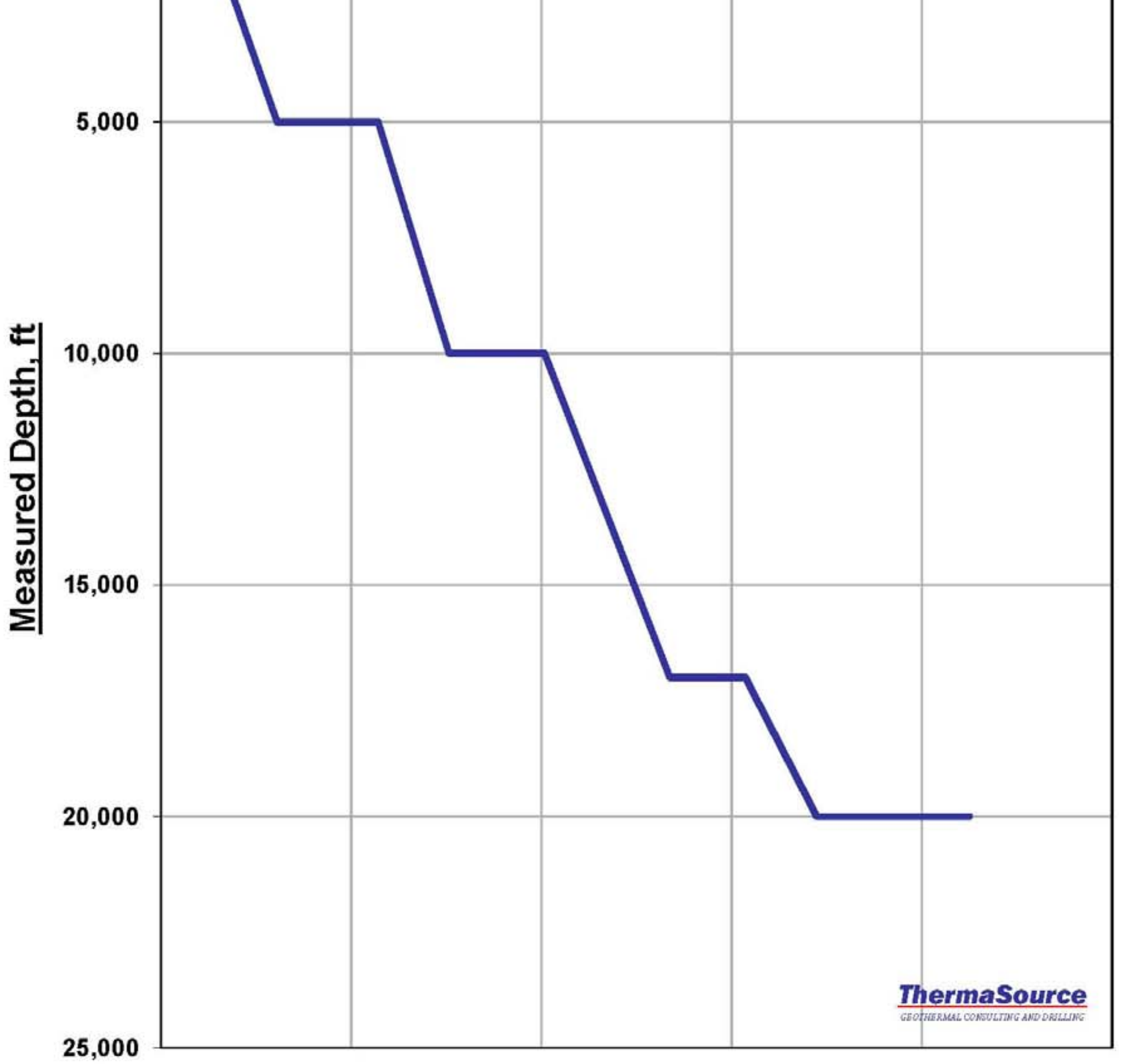

Figure 4-6 Cost versus days plot

5 Analysis of Well Construction Case Study

The drilling on paper exercise performed by Thermasource represents a substantial effort to describe in detail the sequence of steps and tools required to build the case study well. In order to better understand where time and money are spent in this well construction effort it is necessary to organize the nearly 400 listed steps in a categorical manner that reduces what effectively is a job log to operational elements. Representing the well construction process in terms of these elements provides a more manageable way to comprehend the critical building blocks of the process and facilitates the development of strategies to improve the economic bottom line through technological or operational process improvement.

In principle it is possible to break the well construction process down into numerous categorical levels of detail. The current analysis is intended primarily to illustrate the basic approach and therefore uses only two hierarchical levels in order to simplify analysis output. The first hierarchical level describing a step represents the general well construction objective or activity. For this analysis the three fundamental activities are:

- Drilling – Any action associated with extending or expanding the borehole
- Casing – Any action associated with installing permanent hardware within the borehole for the purpose of maintaining borehole integrity
- Logging – Any action associated with measuring borehole or formation characteristics.

Within each activity there are a number of repetitive operations, called tasks, which are performed to complete the activity. Some of these tasks may be performed in more than one activity and some are exclusive to a particular activity. The ten tasks defined in this analysis are:

- Drill: Extending or expanding the borehole
- Trip: Conveying tools or consumables in or out of the hole
- Circ: Circulating fluid for the purpose of cleaning the borehole
- BHA: Assembling or disassembling bottom hole assembly (BHA) components
- Rig U/D: Assembling or disassembling non-BHA surface equipment
- BOP: Conducting blow out preventer (BOP) related activities
- WH Ops: Conducting well head related activities
- RunCsng: Convey casing
- Cement: Cementing related activities
- Log: Logging activities

Time and costs are associated with each step in the ThermaSource script (see Appendix B). The analysis begins by assigning activity and task labels to each step in this well construction process. Times and costs can then be summed for each category to identify their influence on overall economics. The next section will present the time analysis of the operation.

5.1 Time Analysis of Case Study

The well construction script was placed in an Excel spreadsheet with column identifiers for activity, task, time and cost attributed to each step. Pivot tables and charts were then created for different parameter sets to indicate the relative influences of activities and tasks on the overall process. The table and figure below display the cumulative time in days associated with each task by interval and time percentage of each task associated with the overall well construction process (refer to Figure 3-1, well schematic, for phase descriptions).

Phase	Drill	Trip	Circ	BHA	RigU/D	BOP	WH Ops	RunCsng	Cement	Log	Grand Total
1 Surface	1.4	0.5	0.1	1.9	0.4	1.3	0.7	0.5	0.6	0.1	7.5
2 INT-1	12.6	2.8	0.2	2.1	0.2	1	1.2	1.5	0.8	0.7	23.1
3 PROD-1	11.6	4.3	0.5	4.3	0.2	0		1.5	0.7	1.3	24.4
4 PROD-2	22.8	10.4	1.8	3.4	0.1	0		2	0.4	2	42.9
5 PROD-3	10.9	11.8	2.2	3.8	0.1	0		2	0.5	2.5	33.8
6 PL1-TB	0.1	1.6	0.2	3.4	0.1	1.3	1.1	0.7	0.8		9.3
Grand Total	59.4	31.4	5	18.9	1.1	3.6	3	8.2	3.8	6.6	141

Table 5-1 Time breakdown in days by task and interval

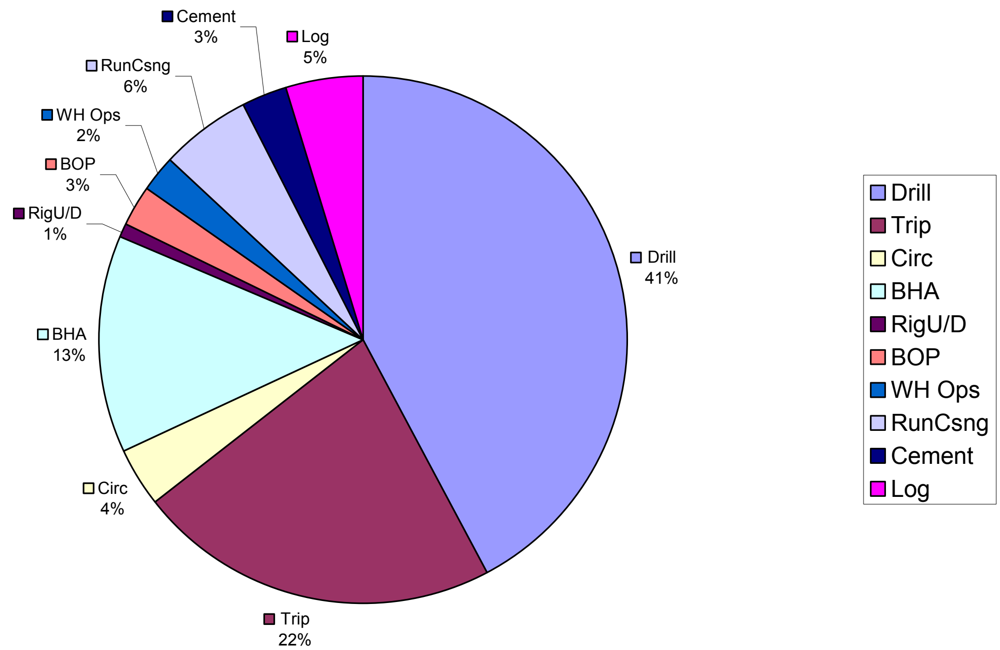

Figure 5-1 Well construction task time percentages

In an ideal process virtually all time would be spent expeditiously creating a borehole with little time required for ancillary drilling tasks and installation of borehole support hardware. Drilling is by far the largest operational time consumer in the presented case, but it only represents roughly 41% of overall operational time. This means that considerable time is spent performing functions not directly related to extending the borehole. In particular it is evident that substantial time is spent tripping (31.4 days) and handling the BHA (18.9 days).

Figures 5-2 and 5-3 below provide alternative representations of times associated with individual tasks by interval. These graphical representations help provide insight into the relative influences of tasks as a function of drilling depth and interval length. It is evident, for example, that the relative time associated with tripping in the deeper intervals becomes a larger fraction of the overall time associated with that interval. This is in general intuitive, but the quantitative impact is particularly informative. It can be seen, for example, that more time is spent tripping than drilling in the 3,000 ft production interval. If drilling penetration rates and causes for tripping remain consistent, it can be assumed that this increasing trend continues for deeper wells. This will be shown to be very important later in the cost analysis section as the cliché "time is money" holds true when it comes to well construction.

Other obvious depth related trends include a greater amount of time spent running casing, circulating and logging as the well gets deeper. It is noted that liners are used for the final four intervals (including the production liner used to tie the production liner 1 back to the surface). If casing had been installed all the way to surface then time and cost associated with casing would be even greater. Tasks apparently not dependent on depth include BHA handling.

Interval length trends can also be gleaned from the data, although it can be argued that more cases would have to be simulated to generate a more reliable statistical correlation. The biggest disparity in terms of relative task contribution can be seen for the drilling and completion of the surface hole. In this case, less time is spent drilling compared to casing and well control related tasks. This is so because much of the work for the latter tasks involves handling and preparatory arrangements that are less time-dependent on the length of the interval. This is also somewhat evident when comparing the 7,000 ft second production interval with the 3,000 ft third production interval. The relative time spent handling the BHA and casing tools increases for the shorter interval, in spite of the greater trip related time, because of the relative interval length independency of these tasks. It is generally acknowledged that it is preferable for drilling intervals to be as long as possible to mitigate telescoping effects and the accompanying costs associated with larger casing sizes and a larger tool inventory. The foregoing also shows that there are time related costs associated with switching between operations.

Tasks times sorted by activity are presented in Table 5-2 and Figure 5-4. Representation of the data in this format separates common tasks with respect to higher level operational objectives. As stated above, tripping is the dominant non-drilling task. Across all activities the lion's share of tripping is performed during drilling (19.2 days when drilling compared to 8 days when casing). BHA handling by comparison is roughly equivalent between drilling and casing at 9.3 days and 8.1 days respectively. All other tasks, with the exception of running casing, have comparatively small time contributions.

Correlation of time consuming tasks with the drilling script provides an indication of the specific actions performed during the task. Tripping tasks, for example, are primarily comprised of bit changes, logging tool conveyance, wiper runs and deployment of

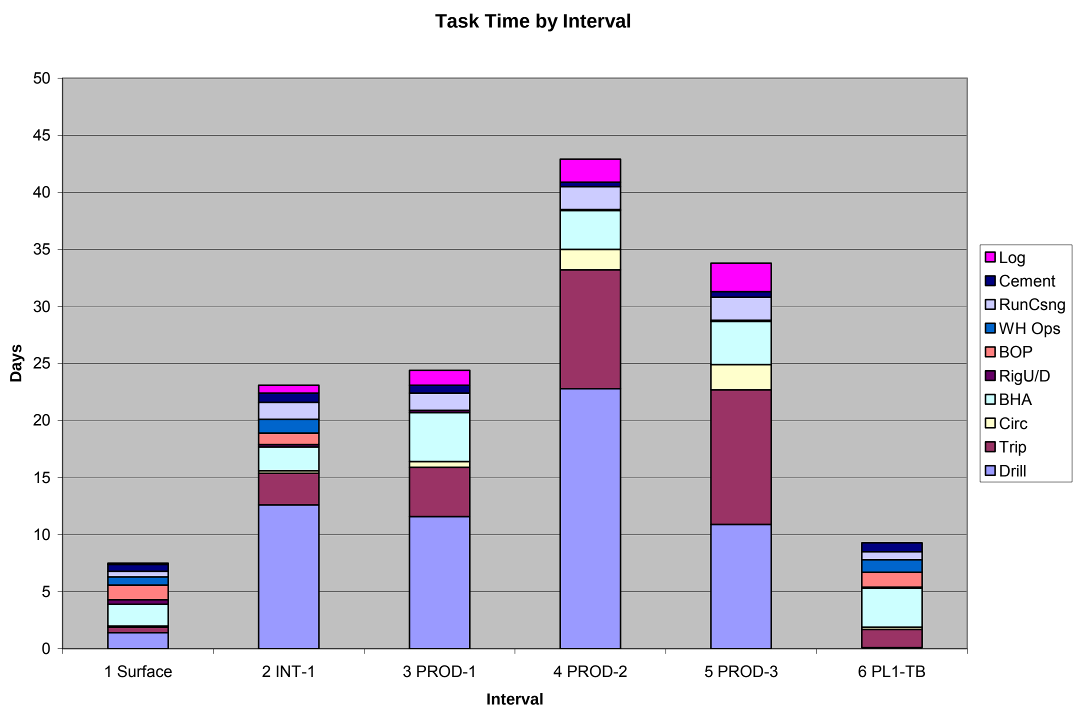

Figure 5-2 Task time chart by interval

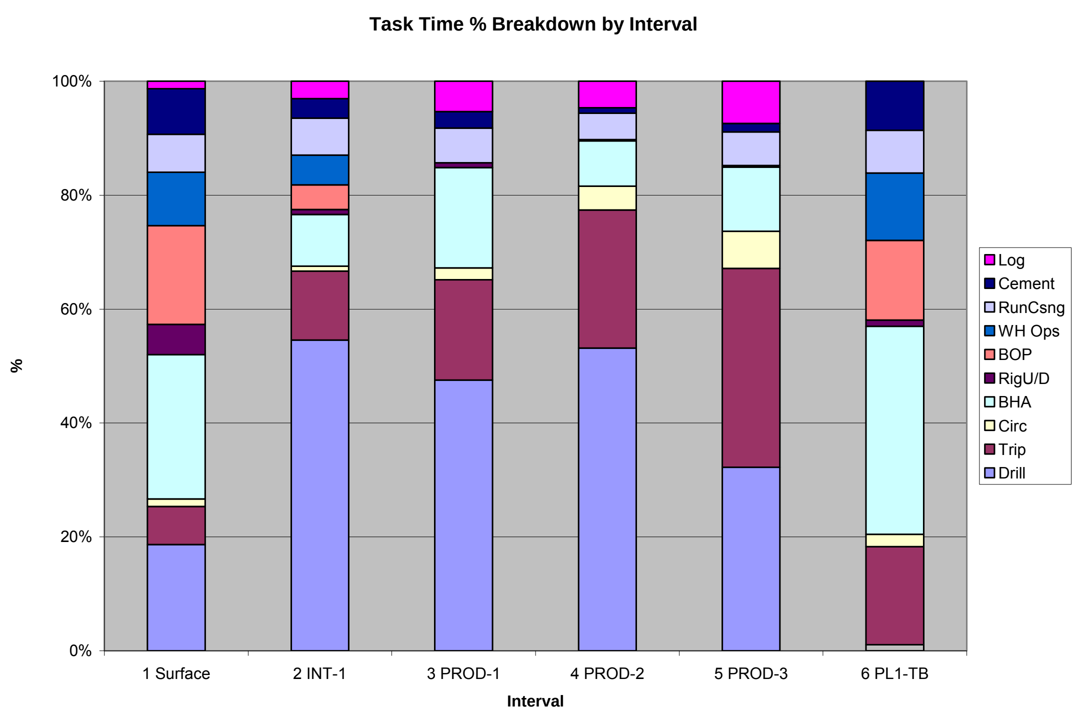

Figure 5-3 Task time chart percent by interval

Activity	Task Code	1 Surface	2 INT-1	3 PROD-1	4 PROD-2	5 PROD-3	6 PL1-TB	Grand Total
Casing	BHA		0.3	2.4	0.4	1.6	3.4	8.1
	BOP	1.3	1	0	0	0	1.3	3.6
	Casing							
	Cement	0.6	0.8	0.7	0.4	0.5	0.8	3.8
	Circ	0.1	0.1	0.2	0.4	0.8	0.2	1.8
	Drill					0.1	0.1	0.2
	RigU/D	0.2	0.2	0.2	0.1	0.1	0.1	0.9
	RunCsng	0.5	1.5	1.5	2	2	0.7	8.2
	Trip	0.2	0.5	0.7	1.2	3.8	1.6	8
	WH Ops	0.7	1.2				1.1	3
Casing Total		3.6	5.6	5.7	4.5	8.9	9.3	37.6
Drilling	BHA	1.9	1.5	1.5	2.6	1.8		9.3
	Circ	0	0.1	0.2	1.3	1.2		2.8
	Drill	1.4	12.6	11.6	22.8	10.8		59.2
	Trip	0.3	1.9	2.8	7.8	6.4		19.2
Drilling Total		3.6	16.1	16.1	34.5	20.2		90.5
Logging	BHA		0.3	0.4	0.4	0.4		1.5
	Circ		0	0.1	0.1	0.2		0.4
	Log	0.1	0.7	1.3	2	2.5		6.6
	RigU/D	0.2	0	0	0	0		0.2
	Trip		0.4	0.8	1.4	1.6		4.2
Logging Total		0.3	1.4	2.6	3.9	4.7		12.9
Grand Total		7.5	23.1	24.4	42.9	33.8	9.3	141

Table 5-2 Task time table sorted by activity

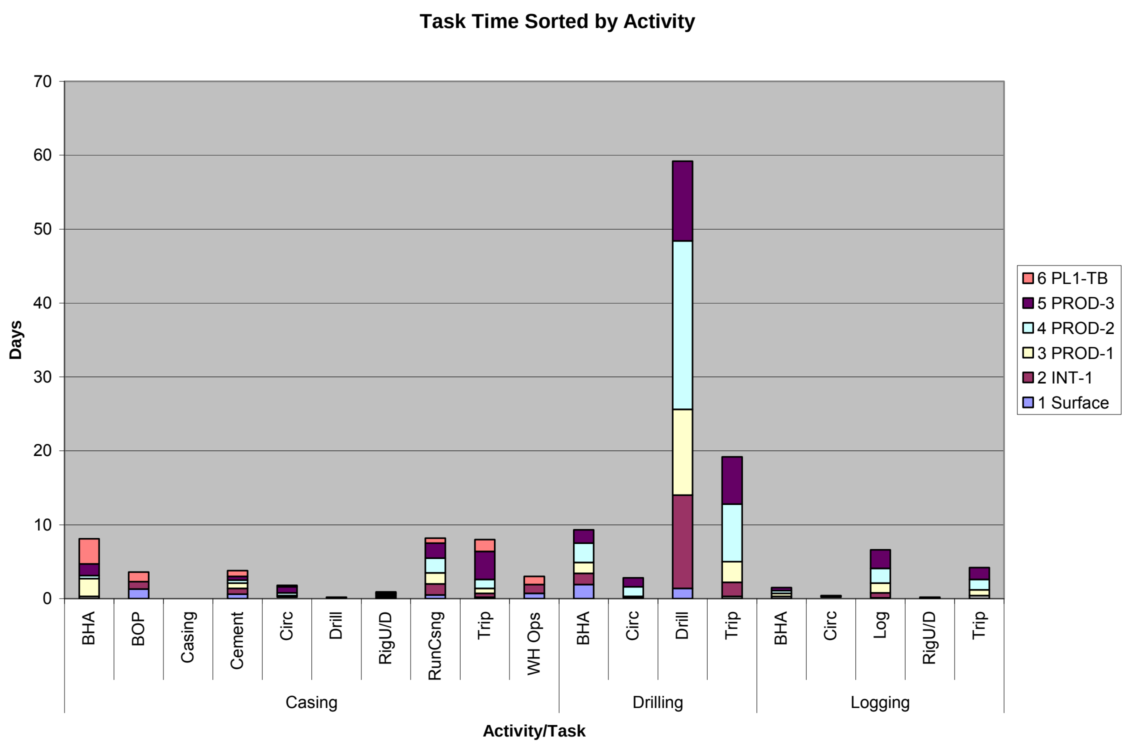

Figure 5-4 Task time chart by activity

casing tools. Further decomposition of tasks in this manner can be used to identify the specific time consuming technologies and/or processes and rank them with respect to quantitative impact. Table 5-3 shows a subtask breakdown of tripping times. Changing worn drill bits and conveying casing tools are by far the largest tripping constituents although significant time is spent on other tripping subtasks.

Subtask	Activity	Time
Changing bits	Drilling	9.8 days
Conveying casing tools	Casing	8 days
Changing tools/bit sizes	Drilling	5.7 days
Conveying logging tools	Logging	4.2 days
Wiper trips	Drilling	3.7 days

Table 5-3 Tripping subtask times

Understanding the temporal impact and nature of subtasks facilitates determination of improvement opportunities. Technology improvement strategies may have potential for diminishing the time associated with some subtasks. Increasing bit life, for example, has the potential to eliminate bit change trips and associated time. Technology substitution strategies may mitigate other subtasks. Casing drilling may represent one such instance by eliminating casing related trips, including running casing, and may potentially provide a more expedient method for changing bits. On the other hand, some subtasks may be deemed to have little improvement potential and therefore may merit little or no focus from the R&D perspective. Prospective R&D thrusts will be discussed in more detail in section 6.

Finally, a summary of key findings in the time analysis is presented below.

- Rock reduction is the largest single time component (59/141 days)
- Tripping is a significant time component (31/141 days)
    - Bit replacement can add significant time to operation (9.8/141 days)
- BHA handling is a significant time component (19/141 days)
    - Improvement opportunity?
- Increasing depth amplifies main time contributors
    - Impact of drilling and tripping may be more pronounced for EGS!
- Increasing depth changes relative weights of different tasks
    - Deeper means less relative time spent drilling
- Interval length also changes relative weights of tasks
    - Shorter intervals are less efficient

5.2 Cost Analysis of Case Study

Some discussion of projected baseline well costs from a historical perspective is merited prior to the cost analysis. The MIT Report presents WellCost Lite calculated costs for a 6 km, 6 interval well in Clear Lake county, CA that is in some respects similar to the presented case. The $13.3M cost of the well presented in the MIT Report is significantly lower than the $20.7M cost estimated for the case in this report. A number of the factors responsible for this disparity are listed below:

- The MIT Report case is presented in 2004 dollars.
- The total time on location for the MIT Report case is estimated to be 126 days as opposed to the 141 days estimated for the current case.
- Different casing dimensions and grades are used in the two cases.
- The cost of basic materials such as casing has increased tremendously since 2004.
- Service costs, such as rig rate, have increased tremendously since 2004 (the current rig rate is roughly 50% greater than that used in 2004).

The large discrepancy between the two cases and listed explanations highlight the importance of reliable estimation of well and completion costs in the economic evaluation of EGS. A relative time frame is required to establish the market conditions and input costs from which accurate well field costs can be predicted. This period related shifting of costs, irrespective of the specific well construction tasks performed and technologies utilized, can also affect the relative influences of well construction elements. Rankings of well construction elements with respect to their quantitative impact can consequently be modified, which in turn affects the potential reward obtained from R&D efforts. These remarks are only intended to provide additional context to the ensuing cost analysis and make the reader aware of other considerations that should be taken into account when evaluating prospective well construction research and development options.

The Thermasource cost estimate represents a pairing of their traditional job cost estimation technique with the expected consumables and aggregate operational times of the presented well construction case. Understanding cost impacts of operational task elements and their related technologies is one of the goals of this well construction case study analysis. It was therefore required that estimated costs be associated with individual script steps in order to calculate aggregate element costs.

The association of costs with specific activities and tasks is in some instances straight forward and in others subjective. Consumable costs, for example, can readily be linked to the activities during which they are used and the particular tasks that employ them. Service rates, on the other hand, can be allocated on more than one basis. The daily rig rate is the simplest example of this ambiguity. The rig is assumed to be present for the duration of operations in the cost estimate. In one approach, costs associated with the rig can be allocated only to rig related activities and tasks. On the other hand, because the rig is being paid for while other tasks, such as logging, are ongoing, rig costs can also be factored into their operational costs.

Because time is such a crucial aspect of operational tasks, the latter approach was selected. The allocation assumptions in this analysis include:

- Costs spread over the duration of the well construction process were factored into the calculation of a universal daily rate. Such costs include rig and support equipment rentals, drilling engineering services, mud engineering, geological services and site services.

- Costs related to specific activities and tasks, such as directional drilling services, casing crew rates and liner hanger services were only apportioned to tasks utilizing those specific services.
- Cementing services and consumables are lumped and associated with individual intervals.
- Casing services and consumables are lumped and associated with individual intervals.
- Drilling consumables not clearly associated with particular drilling intervals or tasks are lumped into a single cost that is not apportioned to individual intervals.
- Drilling consumables related to specific intervals such as bit and mud costs are apportioned to specific intervals.

Relevant service and consumable costs are presented in the table below.

Description	Cost Category	Cost
Daily Universal Rate	Service	$58,130/day
Additional Drilling Services	Service	$20,247/day
Additional Casing Services	Service	$4,654/day
Drilling General Consumables	Consumable	$473,200
Interval 1 Specific Drilling Costs	Consumable	$98,515
Interval 2 Specific Drilling Costs	Consumable	$487,810
Interval 3 Specific Drilling Costs	Consumable	$259,740
Interval 4 Specific Drilling Costs	Consumable	$257,950
Interval 5 Specific Drilling Costs	Consumable	$90,852
Casing Miscellaneous Costs	Consumable	$255,000

Table 5-4 Service and selected consumable costs

Rate related costs are calculated by multiplying step times by the relevant rates. Interval related consumable costs are inserted into the spreadsheet as separate line items. An excerpt of the spreadsheet with costs is presented in figure 5-5 below.

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days	Daily universal rate	Service specific rate	Consumable cost	Total rate
1 Surface	Drilling	BHA	1. Make up 26" bit and 36" hole opener on mud motor.	6	0.3	17439.1	6074.011		$23,513.11
1 Surface	Drilling	BHA	2. Pick up 36" stabilizer and cross over to 6-5/8" HWDP.	4	0.2	11626.06	4049.341		$15,675.40
1 Surface	Drilling	Drill	3. Drill and open 36" hole with motor and HWDP from 80' to 240'.	13	0.5	29065.16	10123.35		$39,188.51
1 Surface	Drilling	Circ	4. Circulate	1	0.0	0	0		$0.00
1 Surface	Drilling	BHA	5. Trip out of the hole and stand back 6-5/8" HWDP.	2	0.1	5813.032	2024.67		$7,837.70
1 Surface	Casing	WH Ops	13. Cut and dress 30" casing.	6	0.3	17439.1	1396.277		$18,835.37
1 Surface	Casing	WH Ops	14. Weld on 30" SOW x API 30", 2000 casing head.	6	0.3	17439.1	1396.277		$18,835.37
1 Surface	Casing	WH Ops	15. Pressure test weld to 500 psi.	1	0.0	0	0		$0.00
1 Surface	Casing	BOP	16. Nipple up 30" BOP with blind ram and annular and connect to flow line.	28	1.2	69756.38	5585.106		$75,341.49
1 Surface	Casing	BOP	17. Function test and pressure test BOP and 30" casing to 250 psi	3	0.1	5813.032	465.4255		$6,278.46
1 Surface	Casing	Cement				0		$220,500.00	$220,500.00
1 Surface	Casing	Casing				0		$170,000.00	$170,000.00
1 Surface	Drilling	Drilling Consu	Includes bits + mud			0		$193,155.00	$193,155.00
1 Surface	Logging	Log	Logging services			0		$125,000.00	$125,000.00

Figure 5-5 Cost spreadsheet excerpt

The most general view of the operational cost breakdown is presented in the pie chart below (Figure 5-6). Drilling related costs dominate this level of well construction costs with drilling services being by far the single largest cost component. Hence the applicability of the time is money phrase. It merits mentioning that although casing and cementing costs are significant for this case, they can in some instances be even a larger fraction of overall cost depending on the well design. If the lower two liners had been tied back to the surface, for example, casing and cementing costs associated with these intervals would have been substantially higher.

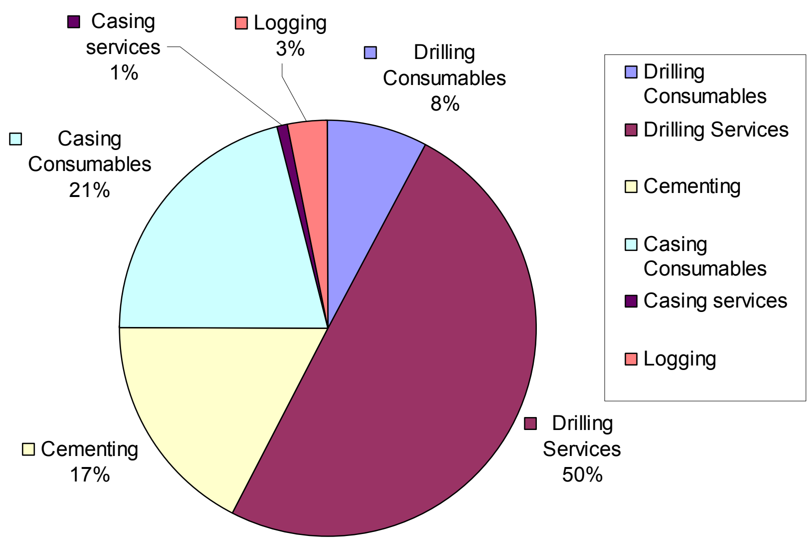

Figure 5-6 Well construction cost breakdown by activity categories

A more informative breakdown is provided by figure 5-7, which shows well construction cost percentages apportioned across tasks. From this perspective no single task element contributes more than 23% to the overall cost. It is therefore implied that well construction cost reduction efforts will have to substantially focus on multiple elements because the ability to substantially reduce any single task cost is inherently limited. The larger components meriting focus are obvious, however it will be pointed out later that many of the smaller cost components also warrant focus because they may be more amenable to improvement through technological innovation or operational optimization.

A strictly cost based ranking of tasks warranting R&D attention can be derived directly from the well cost breakdown by task category. In this manner the order of major tasks by cost fraction is:

1. Drilling (rock reduction)
2. Casing
3. Cementing
4. Tripping
5. Drilling consumables

6. BHA handling
7. Logging

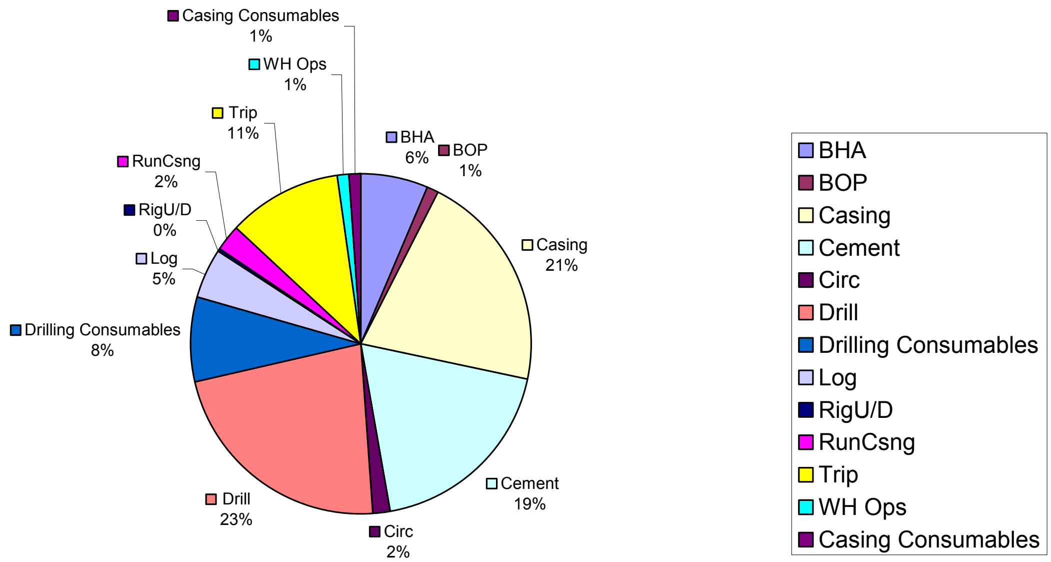

Figure 5-7 Well cost breakdown by task categories

Task cost magnitudes and percentages by interval are shown in Table 5-5 and 5-6 and Figures 5-8 and 5-9. These representations provide insight into relative task cost influences as functions of interval length, depth and borehole diameter. Table 5-6 in particular displays the calculated cost per foot for each task by interval. Although more case studies would have to be performed to produce a more statistically meaningful data set, some inferences can be drawn for the current case. Based on this data, the general cost structure of well construction operations appears to be driven by both competing influences and quasi-fixed type costs (largely independent of interval length, depth or diameter).

The most consistent trend is the drastic reduction in casing and cementing costs associated with decreasing interval diameter. Because of the telescoping effect in which diameters decrease from the top to the bottom of the well this trend also relates to well depth. It is strictly associated with material costs and it is clearly apparent that the use of larger casing diameters is accompanied by significantly higher costs. This also appears to apply to drilling consumables where greater costs are associated with larger holes. Hence the focus within the well construction industry on leaner casing designs that permit the use of smaller diameter casings intervals in the transition from the bottom hole production interval to the surface.

The opposite trend with respect to depth mostly holds for tripping and circulating task costs. In these instances increased costs are caused by the increase in required operational time associated with completing the task from a greater depth. Tripping in particular is worthy of attention because as the hole is extended it becomes a significantly greater portion of the overall interval cost.

Figures 5-9 and 5-10 provide more visual illustrations of these trends, especially in percentage terms. The increase of tripping and drilling cost fractions with interval depth is seen in contrast to diminishing cement and casing cost fractions. Tasks receiving less R&D focus historically, such as BHA handling and tripping, are seen to have significant impact on well construction costs perhaps meriting future investigation.

Task Code	1 Surface	2 INT-1	3 PROD-1	4 PROD-2	5 PROD-3	6 PL1-TB	General	Grand Total
BHA	$148,916	$153,840	$291,501	$252,146	$264,786	$213,468		$1,324,657
BOP	$81,620	$62,785	$0	$0	$0	$81,620		$226,024
Casing	$170,000	$950,000	$1,123,200	$705,600	$217,600	$1,128,000		$4,294,400
Casing Consumables							$255,000	$255,000
Cement	$258,171	$1,258,078	$758,349	$577,114	$368,342	$690,428		$3,910,481
Circ	$6,278	$14,116	$34,045	$132,817	$155,906	$12,557		$355,720
Drill	$109,728	$987,550	$909,173	$1,786,996	$852,750	$6,278		$4,652,477
Drilling Consumables	$193,155	$582,450	$354,380	$352,590	$185,492			$1,668,067
Log	$130,813	$165,691	$200,569	$241,261	$270,326			$1,008,660
RigU/D	$24,183	$12,557	$12,557	$6,278	$6,278	$6,278		$68,132
RunCsng	$31,392	$94,177	$94,177	$125,569	$125,569	$43,949		$514,834
Trip	$36,070	$203,561	$309,909	$768,065	$833,203	$100,455		$2,251,263
WH Ops	$43,949	$75,341				$69,063		$188,354
Grand Total	$1,234,276	$4,560,146	$4,087,861	$4,948,436	$3,280,253	$2,352,097	$255,000	$20,718,069
Cost/ft	$2,469	$1,013	$818	$707	$1,093			

Table 5-5 Task cost pivot table by interval including interval cost per foot

	1 Surface	2 INT-1	3 PROD-1	4 PROD-2	5 PROD-3
BHA	$298	$34	$58	$36	$88
BOP	$163	$14	$0	$0	$0
Casing	$340	$211	$225	$101	$73
Casing Consumables	$0	$0	$0	$0	$0
Cement	$516	$280	$152	$82	$123
Circ	$13	$3	$7	$19	$52
Drill	$219	$219	$182	$255	$284
Drilling Consumables	$386	$129	$71	$50	$62
Log	$262	$37	$40	$34	$90
RigU/D	$48	$3	$3	$1	$2
RunCsng	$63	$21	$19	$18	$42
Trip	$72	$45	$62	$110	$278
WH Ops	$88	$17	$0	$0	$0
Grand Total	$2,469	$1,013	$818	$707	$1,093

Figure 5-8 Task cost per foot

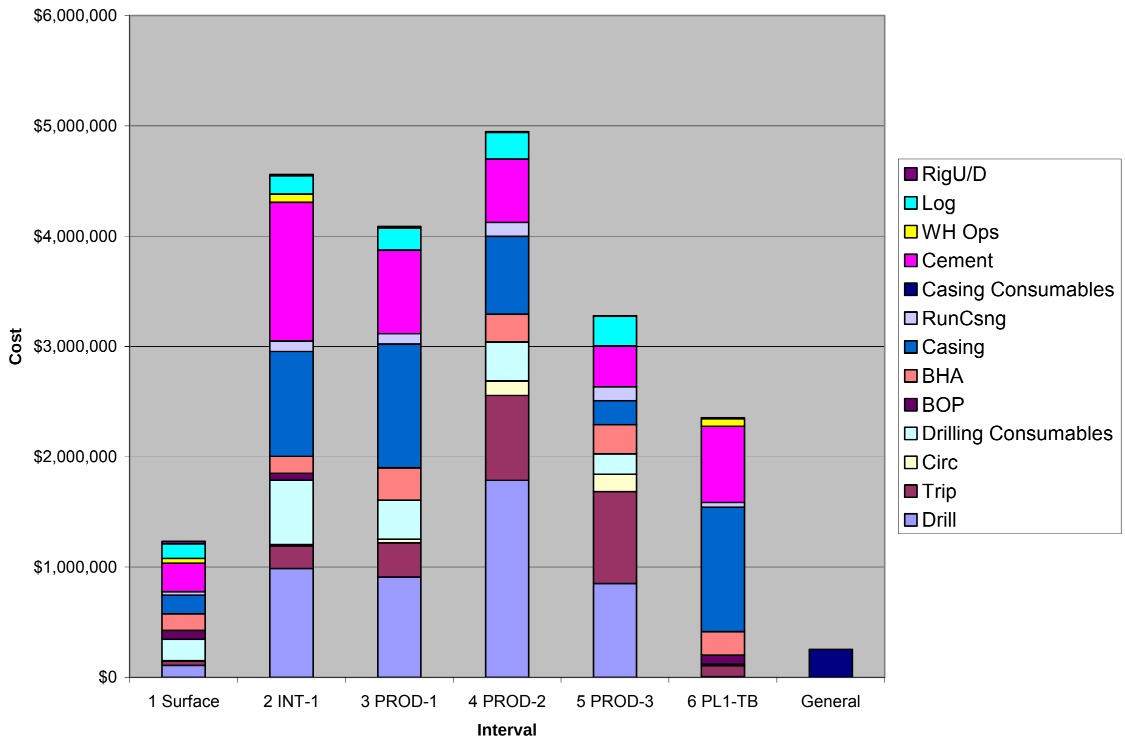

Figure 5-9 Task cost by interval

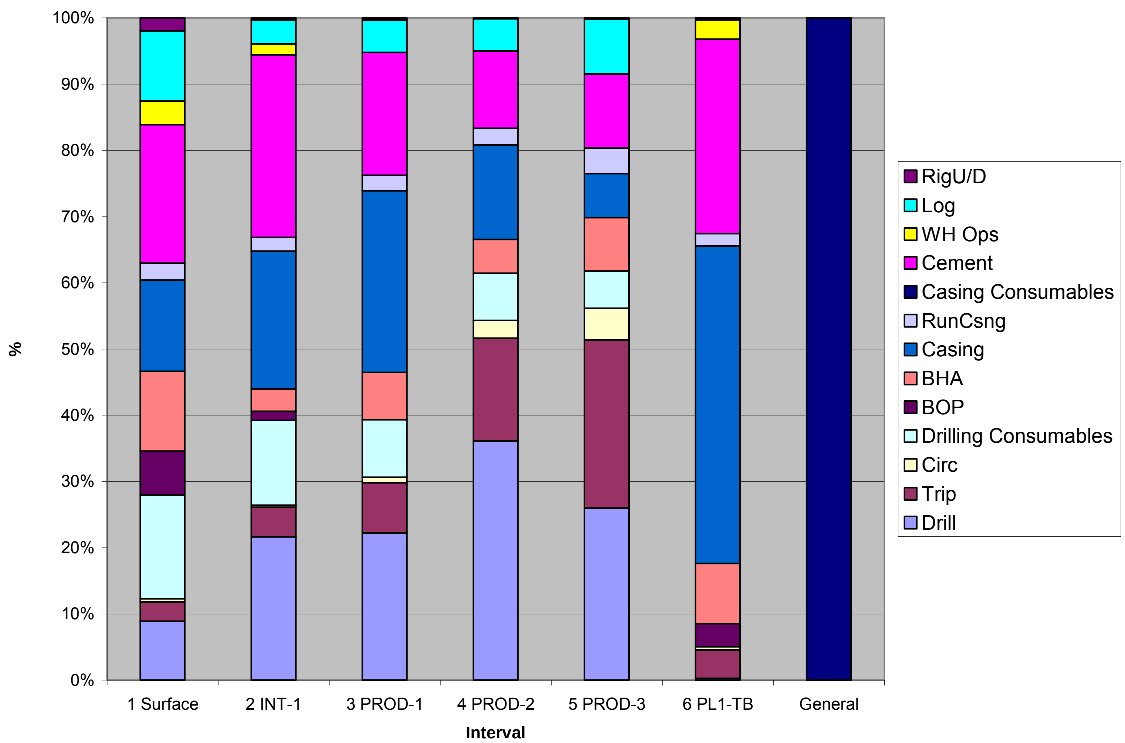

Figure 5-10 Task cost percentage by interval

A finer level of task resolution is provided in Figure 5-11 by segregating task costs by activity. As described in the previous section, analysis of the cost basis at this level, in the context of the drilling script, facilitates the identification of cost reduction strategies founded on technology development and/or operational process optimization. A large fraction of the cost of tripping, for example, results from bit changes. Bit change costs are also a significant portion of BHA handling costs. Improving bit life therefore represents a method for reducing the cost impact of both tasks.

Focus areas for well construction R&D based on cost drivers are summarized below. This list is rather general and primarily reflects the more obvious conclusions extracted from this study. The following section will provide a more detailed description of R&D focus areas that address both functional and cost driven well construction considerations.

- Improve ROP
    - Bits, tools and processes
- Develop more durable tools
    - Eliminate trips and handling
- Improve casing design
    - Minimize production borehole diameters
    - Minimize or eliminate telescoping effects
    - Improve cementing practices
- Improve operational efficiency
    - Reduce trips
    - Improve BHA handling
    - Develop best practices

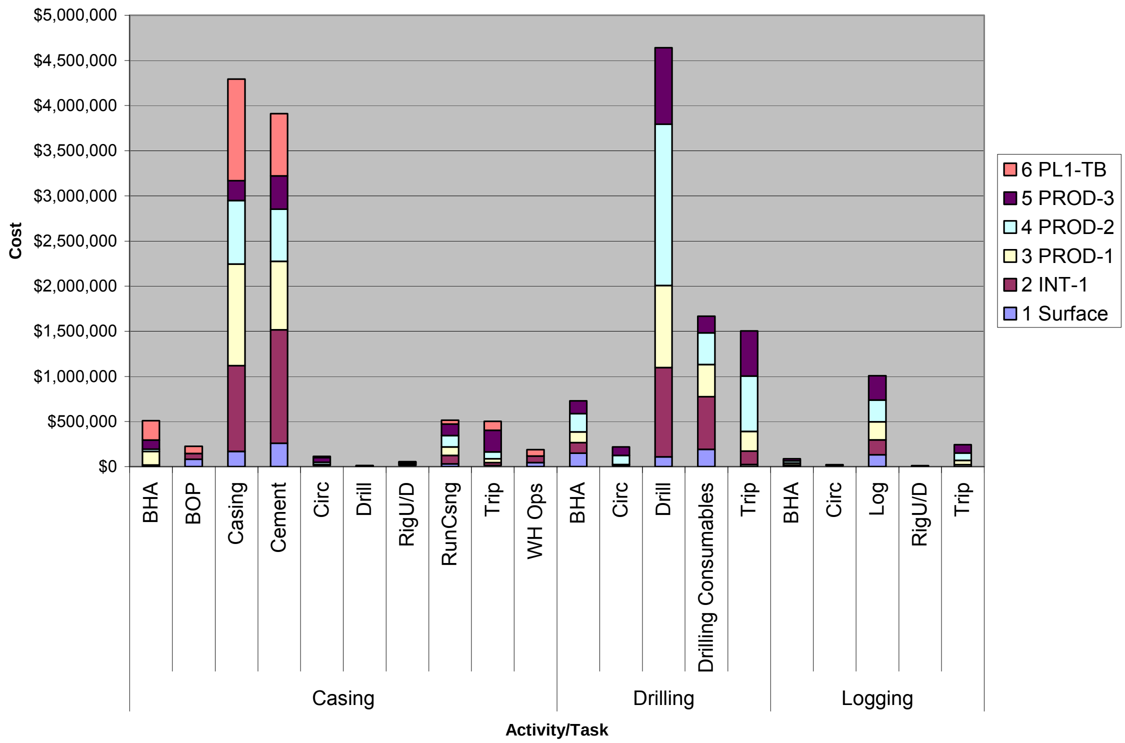

Figure 5-11 Task costs sorted by activity

A high level summary of the key findings of this operational analysis is presented below. It is intended to highlight the more salient observations on the well construction process as a whole.

- There is no economic silver bullet!
    - Reducing well construction cost will require multiple focus areas
- Non-hole making tasks are significant cost drivers
    - Tripping and BHA handling are not trivial contributors
- Potential impact of new technologies can be evaluated in conjunction with this type of analysis
    - The quantitative basis of the method permits ranking of focus areas. A more concrete assessment of the potential benefits of prospective projects can be obtained by employing valuation methods such as return on investment.
- Task and consumable cost structure changes with depth
    - Some new technologies will impact well construction in general
    - Relative impact of other technologies will be dependent on well specification and well construction phase

6 Well Construction R & D Recommendations

The purpose of this section is to define critical well construction research & development elements that enhance EGS viability prospects and improve well construction economics. Some of the research recommendations are directly related to the preceding operational analysis. Prospective projects in this category can be more traditionally assessed using "return on investment" type valuation methods because they are readily compared to current practices. In general they supplant or augment existing methods and technologies.

Other recommendations related to the well construction considerations outlined in Section 2 of this report do not address current practice, but are critical to increasing the probability of EGS success because they directly affect EGS proof of concept. Assessing the value of these potential projects is difficult due to the current conceptual nature of EGS and the inherent uncertainty associated with basic research. Projects of this type represent a best guess of the key technical hurdles that will have to be overcome in order to execute EGS. They are also critical components of any systematic approach to develop EGS in an efficient manner.

Three categories of well construction R&D are hereafter defined in order to logically organize efforts based on their direct relatedness to future EGS application. They are:

1. "Systems Engineering" type research areas to better define ill-framed EGS well construction issues and needs
    - Typically impact other critical EGS areas, e.g. reservoir creation, production, intervention
    - Will ultimately be used to add to category 3 research elements
2. Recognized enabling technologies
    - Applies to technology types with current limitations that are generally recognized as necessary to future EGS implementation, e.g. HT tools
3. Target technologies
    - Applies to well defined issues and problems

These research categories can more simplistically be summarized as: 1) Efforts to determine critical issues and needs not yet recognized. 2) Efforts to meet needs that are very likely to be important. 3) Efforts to meet needs that we know today to be important.

It is pointed out that the majority of research lines that will be recommended reflect the historical focus of the DOE Geothermal Technologies program. This congruence is hopefully perceived as a good indication of appropriate direction of the program. The primary difference between the recommendations in this report and previous technology evaluations is the method of categorizing research areas based on their role in the EGS research program and the attempt to rank, where possible, recommendations based on their quantitative impact on well construction activities. It is hoped that this approach can be further developed in the future as a method for both identifying critical R&D needs and determining how maximum value can be obtained from R&D efforts and funding.

The following sections will discuss recommended lines of investigation within each of the aforementioned R&D categories. Additional discussion of select technologies of interest is presented in Appendix C.

6.1 Systems Analysis (Category 1)

Category 1 research thrusts are most concisely described as EGS systems engineering. The main development components of EGS (site identification, resource characterization, well construction, reservoir creation and reservoir operation) exhibit high degrees of interdependency. Changes in the methods or technologies used in a particular stage of the EGS process may adversely affect or require changes to another stage as described in section 2. Understanding these interdependencies and understanding their potential impacts is therefore of the utmost importance to EGS development.

EGS systems engineering with respect to well construction broadly encompasses four topics: EGS economics, well field design, well field construction and well completion. Each of these topics will be briefly covered to illustrate how they are likely to affect well construction practice and R&D goals.

EGS economics – EGS economics is an overarching theme in all areas of EGS research & development. Functional realization, although unquestionably crucial, is only a step in the path towards EGS contribution to U.S. energy needs. Well field construction costs have historically proven to be large fractions of geothermal capital investment costs and this is generally assumed to be equally true for EGS. On the one hand, evaluating or predicting well field construction costs as EGS development progresses helps understand prospects for commercial success. On the other, a better and more detailed *a priori* appreciation of <u>acceptable</u> well field construction costs can help focus R&D efforts by imposing cost based design constraints. Such economic analysis requires a comprehensive view and study of all EGS components.

Well field design – The creation and exploitation of the EGS reservoir is vitally contingent on the ability to generate the volumes, surface areas and flow rates needed to effectively and economically extract the thermal resource. These three parameters in turn are heavily influenced by the specific manner in which the subsurface is accessed. Well field design is currently a very open aspect of EGS. There are numerous yet undetermined facets of its preferred form including: the number of wells to be used (e.g. doublets, 5-spots, etc.); preferred borehole orientations (e.g. vertical, inclined, horizontal); and monobore vs. multilateral designs. Resolving these fundamental issues can result in significantly different well construction strategies that are likely to impact well construction R&D objectives. Future investigation of well field design in the EGS systems context is warranted to develop a better appreciation of well construction needs and how they may change if well field design changes.

Well field construction - Systems level analysis of well field construction is required to efficiently synchronize this step in EGS development with previous and following steps. This primarily involves the linking of real-time data to exploration data and well construction operations to subsequent formation behavior. The former is useful for ensuring that information acquired during well construction corresponds well to prior planning. Examples of the latter include managing pressure while drilling or dealing with lost circulation while drilling. In both cases actions taken during well construction can reduce formation permeability with consequent production problems. System understanding at this level is very mature in the oil and gas and current geothermal industries, often leading to different operational practices due to application differences, but perhaps should be evaluated in the context of future EGS development.

Well completion – In some respects, this is one of the biggest gaps in current EGS planning and understanding. Recognized subjects of significance in this area have primarily focused on casing design. Relevant objectives include:

- Appropriately sizing production intervals to meet necessary production rates
- Reducing cost through leaner casing design or elimination of casing strings
- Optimizing cementing practices to reduce cementing costs
- Devising strategies to improve life cycle costs by protecting casings (e.g. more resistant and long lasting cement) or using longer lived casing materials
- Incorporating well workover considerations into casing design to reduce life cycle costs

Production interval completion by contrast has received little or no attention in the geothermal literature. As mentioned in section 2, current geothermal completions are generally open hole or at least present continuous communication throughout the production interval. This is in contrast to many oil and gas applications where complex completions are used in production intervals to more optimally engage the reservoir. These approaches should be evaluated for EGS with the following potential objectives in mind:

- Facilitation of selective stimulation along the production interval
- Controlling zonal injection to more effectively extract thermal resource from the formation
- Cost and functionally effective intervention to reduce injection loss
- Cost and functionally effective intervention to mitigate the effects of short-circuiting
- Cost and functionally effective intervention to address production loss due to chemical or erosion effects

In summary, EGS systems engineering is required to optimize R&D resources by anticipating potential issues and identifying the problems that must be solved to increase prospects of success. The currently fluid underpinning of the EGS concept makes this especially true. As more EGS field experience is gathered, this uncertainty will be reduced but it is likely that an umbrella of system level investigation will always be required for steady advancement to occur.

6.2 Enabling technologies (Category 2)

There are numerous enabling technologies that have been historically deemed necessary to successful EGS development. These technologies are considered to be enabling because they relate more to general capabilities than specific needs in the EGS well construction process. They are mostly based on current practices in analogous industries, such as oil and gas, which have significantly improved operational efficiency or capabilities. These technologies and their general application will be subsequently described.

High temperature electronic components for drilling and logging tools (> 200 °C) – Drilling and logging tools for use in well construction and formation evaluation are mainstays of the upstream oil and gas operational inventory. These tools are used to optimize exploitation of and recovery from the reservoir. By comparison, very little use of these tools is made in current geothermal practice. The higher temperatures of geothermal applications typically prevent their use because of temperature limitations of the tools. Regardless of the specific function (sensor modality), a host of supporting components is required for the operation of all downhole tools. A typical downhole tool architecture diagram is presented in Figure 6-1 below. It can be seen that a variety of high-temperature components must be developed aside from the sensor itself in order for the tool to function. A list of representative components and capabilities that must be developed to enable the use of drilling and logging tools in high-temperature EGS applications includes:

- Processors
- Multi Chip Modules (MCMs)
- Higher bit A/D converters
- Field programmable gate array/EEPROM
- Failsafe capacitor
- Oscillators
- Large memory arrays
- Batteries
- Addressing reliability issues
    - Solders
    - Encapsulation material
    - Seals
    - Strain gage mounting

More detailed descriptions of logging while drilling and measurement while drilling technologies are provided in Appendix C. It is also noted that a large number of tools currently exist in the oil and gas industry for which a geothermal use is currently unclear. A thorough assessment of this inventory and its potential use in geothermal applications would require a team of experts from disciplines including tool and sensor design, the geosciences, well construction and reservoir engineering. Potential tool use and benefits would have to be assessed in the context of whether or not the measurement physics is suitable for the geothermal formation, potential issues with log interpretation and how the information would be used by reservoir engineers or well construction specialists to improve EGS implementation. A more detailed tool study is recommended for future investigation as a distinct effort.

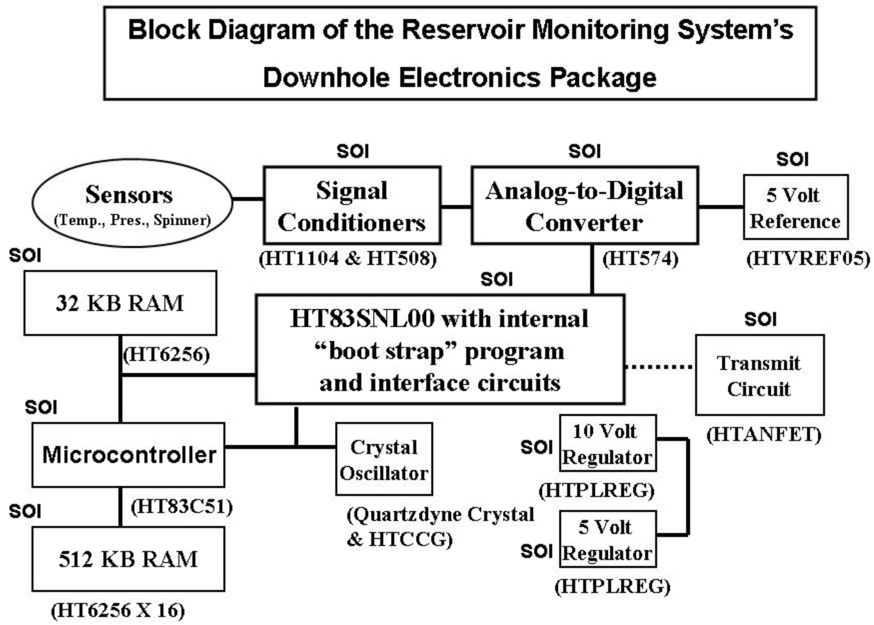

Figure 6-1 Typical downhole tool architecture

High-temperature, hard rock directional drilling tools – Although required borehole curvature specifications and directional drilling capabilities have not yet been defined for EGS, it is likely that directional drilling capabilities will be required. Directional drilling tools will have to withstand the high temperatures and hard rock lithologies expected in EGS applications. There is evidence that current industry capabilities can meet the former conditions in some applications. Baker-Hughes Inteq, for example, has recently directionally drilled a well in a Basalt formation for Ormat's Puna geothermal project in Hawaii with a reported static temperature of 650°F using their 8" Ultra series motor with Navitrak MWD tool. Based on conversations with Inteq, the use of current directional drilling technologies is predicated on the ability to keep electronic components cool via drilling mud circulation. Future application and development of these types of directional drilling technologies should be monitored and discussed with both operators and service companies to assess and promote EGS applicability.

High-temperature production and service isolation tools – Zonal isolation capability is currently considered to be important to EGS production and intervention practices. The use of packers to selectively isolate or treat production zones is recognized to be essential to operations such as lost circulation remediation and stimulation. Application of existing tools in geothermal applications is primarily affected by temperature limitations of elastomeric components, differential pressure capabilities and maximum inflation diameters. The use of cement inflated packers is considered to be currently feasible among service companies, however those surveyed indicate that the current capabilities of retrievable and swellable packers, particularly in open hole applications, are currently not suitable for EGS applications. Advancement of these technologies will have to occur to increase temperature and differential pressure capabilities.

Improved telemetry capabilities – High baud rate telemetry in general and low baud rate telemetry in some applications will have to be improved for use in EGS applications. These capabilities are required for drilling and logging tools used in applications where operational decisions are made based on data acquired in real-time. High-temperature, high speed telemetry capabilities have been demonstrated in the past in Sandia's Diagnostics While Drilling program where real-time drilling dynamics data has been used to improve drilling performance and reliability. However, more cost effective telemetry methods will have to be developed for more wide-spread commercial use of these capabilities.

Low baud rate telemetry applications currently employ mud pulse technologies. There are many applications currently in the geothermal industry in which low density media, such as air or aerated fluids, are used to mitigate lost circulation problems. Telemetry methods in these fluids are either limited or non-existent meriting future development.

High-temperature pumps – It is likely that high temperature submersible pumps will be required to facilitate EGS fluid production. Although a significant improvement in capabilities has developed for these technologies, they are largely unproven in the deep, large wellbore, high temperature environment expected for EGS. Work with service companies to advance these technologies to meet EGS needs is warranted.

High-temperature smart completions – The value of developing high-temperature smart completions for measurement of production parameters and flow control applications should be evaluated. Successful development of this class of technology has the potential to improve reservoir operation and management practices. These technologies should be considered in the context of alternative methods for operating and managing the reservoir. Development of this technology will require advances in HT electronics, valves and telemetry.

6.3 Known technological needs (Category 3)

Technology needs in this category are grouped in five areas in rank order of importance with respect to reducing well construction costs. They are: increasing rate of penetration (ROP), leaner casing design, reducing trip time, operational optimization and high-temperature tools.

Increasing ROP – This is a historically recognized focus area in geothermal technology research due to the low rates of penetration characteristic of many geothermal applications. The cause of this drilling difficulty (hard, abrasive and hot formations) has been a point of distinction in the past between geothermal and oil and gas applications. This distinction is quickly becoming blurred as the oil and gas industry more frequently encounters more geothermal-like drilling conditions as easy-to-drill discoveries become scarcer. This convergence of interests may set the stage for adapting some of the more effective oil and gas drilling technologies for use in geothermal-like conditions. Specific efforts should focus on:

- Transitioning aggressive O&G and waterwell/mining drilling technologies to geothermal (PDC bits and hammers)
    - Identify technical barriers and application issues
    - Conduct controlled field trials of candidate technologies to separate anecdotal failure reports from true technology limitations
- Developing economical drilling optimization tools using downhole data
    - MWD with drilling dynamics data
    - Methodologies for minimizing mechanical specific energy

Leaner casing design – Although this is partially covered in category 1 research recommendations, there are some existing niche technologies that are worthy of mention for future R&D focus. These technologies primarily mitigate telescoping effects by reducing the magnitude of diameter change between intervals.

- Expandable tubulars

Reducing trip associated time – This is a direct output of the operational analysis with significant cost saving potential. Sample objectives to address this area include:

- Development of longer lasting drill bits to eliminate trips
- Development of more efficient bit trip methods such as bit removal through tubing using wireline (as done for casing drilling)
- Use of techniques such as casing drilling that eliminate casing runs and expedite bit tripping

Operational optimization – Operational optimization may involve both surface operations (such as BHA handling) and downhole operations. It can be applied towards more expeditious execution of individual tasks or modifications to operating procedures involving multiple tasks. The latter can take the form of eliminating steps, combining steps or performing steps in parallel.

- Develop “best practices” for repetitive tasks
    - BHA assembly/disassembly
    - Lay down of drill pipe
    - Operational analysis of rig equipment
- Evaluate potential benefits of special purpose rig support equipment such as automated pipe handlers
- Supplement MWD with LWD to reduce time associated with switching over from drilling to logging operations

High temperature tools – The list of tools below represent deficiencies in the current geothermal tool inventory due to temperature limitations. These tools are critical to various components of EGS involving creation, operation or maintenance of the reservoir.

- 3D fracture monitoring: Reservoir creation
- Minimum principal stress magnitude and direction measurement: Reservoir creation
- Pressure/Temperature measurement: Stimulation
- Flow meters: Production and intervention

- Fluid samplers: Production and intervention
- Calipers: Well construction

7 Conclusions

There are numerous components of EGS development that will involve significant advancement of the current commercial geothermal state of the art. Well construction is but one of these constituents and it is the purpose of this report to evaluate the core technologies critical to future EGS implementation. The objectives of this assessment are two-fold:

1. Evaluate the ability of existing technologies to develop EGS wells.
2. Identify critical well construction research lines and development technologies that are likely to enhance prospects for EGS viability and improve overall economics.

A methodology for analyzing EGS well construction needs is presented to achieve these ends. The methodology is built on case study analysis and provides a quantitative description of the fundamental elements of the well construction process. A vertical 6 km well profile is developed to represent a baseline departure from current hydrothermal well construction practice. The operations, steps and tools required to build the baseline well using current methods and technologies are defined, with no apparent technical obstacles, affirming the feasibility of the first objective above. However, for a variety of reasons listed in the cost analysis section, the cost of this well is estimated to be significantly higher than similar wells quoted in the MIT Report. In the context of the EGS economic analysis presented in the MIT Report and previous geothermal programmatic objectives, this estimate further amplifies the importance of reducing well costs.

With respect to the second objective of this evaluation, a detailed operational and economic analysis of the well construction scenario is performed to systematically identify time and cost intensive constituents. Well construction elements are quantified and ranked in terms of temporal and economic impact. It is shown that there are numerous operational and technological components that drive well construction economics with no single dominant component. Future efforts to significantly reduce well construction costs will therefore require multiple focus areas. Significant process elements meriting focus in order of cost impact include:

1. Drilling (extending the borehole)
2. Casing
3. Cementing
4. Tripping (conveying tools and materials)
5. BHA handling (assembling/disassembling tools)

Research approaches to address these significant areas are outlined in this report. Many of the proposed lines of investigation parallel previous efforts in the DOE Geothermal Technologies Program focused on hydrothermal applications. However, it is shown in this evaluation that there are likely to be significant differences between EGS implementation and current hydrothermal practice that may alter some of the investigation’s conclusions.

In order to apply this methodology, it was first necessary to establish prospective EGS well field specifications. The process of formulating a realistic description of a proposed well design led to the conclusion that the present understanding of EGS is too limited to generate a reliable specification. In particular it was argued that indeterminacy in other areas of EGS implementation including reservoir creation, operation and management introduce uncertainty in preferred well field characteristics. Thus, thoroughly evaluating the current status of well construction technology with respect to EGS itself requires a more specific definition of other fundamental EGS development areas. *The presented case study and analysis therefore primarily represents a demonstration of the utility of the methodology employed for analyzing well construction needs and ranking of R&D objectives.*

The current conceptual nature of EGS and associated uncertainties stated above highlight the importance of a systematic approach to understanding R&D needs beyond the current hydrothermal paradigm. Clarification or at least mitigation of these ambiguities will promote more effective use of program resources in the effort to realize EGS.

Two extensions of this work towards this end might include:

1. EGS Systems Engineering or Systems Analysis – This effort must include all subject matter experts across the program and focus on detailed planning, design and implementation of likely EGS scenarios. The determination of EGS component interdependencies in particular will be critical to anticipating potential problems and identifying R&D needs. In regard to well construction this will promote more robust well field designs and technology evaluations.

2. Conduct additional case study analyses – Application of the case study analysis method utilized in this report can be extended to a variety of well construction scenarios to improve understanding of potential variability in technological and cost drivers. This should ideally occur in conjunction with EGS Systems Analysis recommendations. As an immediate extension of the present work a representative set of specific target lithologies and well profiles can be established and analyzed.

Appendix A

A.1 Methodology for calculating production rate and pressure profiles

For single phase, incompressible, uniform-temperature fluid flowing in a borehole, Bernoulli's equation governing the pressure difference between two points is

$$\left.\left(\frac{u^2}{2}+\frac{p}{\rho}-gz\right)\right|_2=\left.\left(\frac{u^2}{2}+\frac{p}{\rho}-gz\right)\right|_1 \pm hl_{2-1}, \qquad \text{A1}$$

where the plus sign applies to a production well and the minus sign to an injection well (reversal of flow direction). The sign for the depth (z) term is negative because depth is taken as positive downward. The head loss term (*hl*) is

$$hl_{2-1}=f\,\frac{L}{D}\frac{u^2}{2}=f\,\frac{L}{D}\left(\frac{4\dot{m}}{\pi\rho D^2}\right)^2. \qquad \text{A2}$$

Heat loss along the borehole and compressibility of the fluid affect the density and pressure in equation A1. However, these effects are significantly less than the effect of the temperature and pressure differences between the production and injection wells. This allows the assumption of an incompressible, uniform-temperature fluid within each borehole. By design, the pressure in the system is kept above local boiling point allowing the assumption of a single phase fluid. Since the flow is incompressible, there is a uniform temperature within each wellbore, and because the pressure change at casing points due to diameter change is less than a few psi, the velocity terms in equation A1 can be ignored.

For the production well Bernoulli's equation becomes

$$\left(\frac{p(z)_P}{\rho_P}-gz\right)=\left(\frac{p_{PWH}}{\rho_P}+0\right)+f_P\,\frac{z}{D}\left(\frac{4\dot{m}}{\pi\rho_P D^2}\right)^2, \qquad \text{A3}$$

or

$$p(z)_P=P_{PWH}+\rho_P gz+f_P\,\frac{\rho_P z}{D}\left(\frac{4\dot{m}}{\pi\rho_P D^2}\right)^2. \qquad \text{A4}$$

Similarly for the injection well Bernoulli's equation becomes

$$\left(\frac{p(z)_I}{\rho_I}-gz\right)=\left(\frac{p_{IWH}}{\rho_I}+0\right)-f_I\,\frac{z}{D}\left(\frac{4\dot{m}}{\pi\rho_I D^2}\right)^2, \qquad \text{A5}$$

or

$$p(z)_I=P_{IWH}+\rho_I gz-f_I\,\frac{\rho_I z}{D}\left(\frac{4\dot{m}}{\pi\rho_I D^2}\right)^2. \qquad \text{A6}$$

Flow through the reservoir is assumed to be governed by a productivity index (PI), thus

$$\dot{m} = PI(\,p(L)_I - p(L)_P) \qquad \text{A7}$$

Substituting equations A4 & A6 into equation A7 gives

$$\dot{m} = PI\left\{(P_{IWH} - P_{PWH}) + (\rho_I gz - \rho_P gz) - \left(f_I \frac{\rho_I z}{D}\left(\frac{4\dot{m}}{\pi\rho_I D^2}\right)^2 + f_P \frac{\rho_P z}{D}\left(\frac{4\dot{m}}{\pi\rho_P D^2}\right)^2\right)\right\} \qquad \text{A8}$$

The first term in the braces is a forcing function due to the difference in pressure between the injection and production wellheads. The second term is the buoyancy effect due to the difference in the densities of the fluid in the injection and production wells. The last term is the head loss due to friction. The friction factor (*f*) is a function of flow rate and so the equation is an implicit equation for flow rate. However, as long as the flow rate is high and flow is turbulent, the friction factor is relatively independent of flow rate and the equation can easily be solved by iteration (or by solving the quadratic equation for $\dot{m}$).

Introduction of an ESP causes a step change in pressure at the pump set depth and requires the addition of a forcing function to be added within the braces of equation 8.

A.2 Nomenclature:

u: velocity,
p: pressure,
ρ: density
g: acceleration of gravity,
z: depth,
hl: head loss due to friction,
f: friction factor,
L: length borehole,
D: diameter,
$\dot{m}$: mass flow rate,
P: production well (subscript),
I: injection well (subscript),
PWH: production well head (subscript),
IWH: injection well head (subscript), and
PI: reservoir productivity index.

Appendix B – Thermasource Inc. Documentation

The information below comprises the detailed well design information and drilling script provided by Thermasource , Inc. as a paper "simulation" of a baseline EGS well.

B.1 Thermasource Inc. Overview Documentation

This section provides detailed description of the well specifications, including casing and cementing, as well as the underlying assumptions on formation conditions and drilling performance.

ThermaSource

3883 Airway Drive
Suite 340
Santa Rosa, CA 95403
TELEPHONE: (707) 523-2960

Drilling Program	
Operating Company	Sandia National Labs
Field	Clear Lake
Well	EGS 1
Location	Lake County, California
Well Type	Vertical 20,000 Feet
Rig	3000 HP
Drilling Engineer	Robert J. Swanson
Date of Issue	August 25, 2008

Well Information Table	
Operator	**Sandia National Labs**
Well Name	Clear Lake 1 – EGS Well
Location	County: Lake State: CA
Surface Coordinates Lat / Long	Latitude: Longitude:
Coordinates Grid US (ft)	Northing: Easting:
Ground Elevation (ft)	2500'
Rotary Table Height (ft)	45'
Final Total Depth	20,000' TVD
Bottom Hole Target	0' N and 0' E of surface
Target Zone:	570^{o} F Bottom Hole Temperature
Planned Days	143
Planned Cost	$21,000,000
Objective:	Drill vertical well to 20,000 feet with 7" cemented liner in preparation for stimulation program.

Open Hole	Cased Interval		Casing Specifications
Size	MD	Top	
36"	500'	Surface	30", 1.0" Wall, 310 ppf, X-56 Line Pipe, Drill Quip – Quick Stab Weld on Casing Connectors
26"	5000'	Surface	20", 169 ppf, N-80, BTC, Seamless Casing
17-1/2"	10,000'	4800'	13-5/8", 88.2 ppf, P-110, BTC, Seamless Casing
12-1/4"	17,000'	9800'	9-5/8", 53.5 ppf, P-110, BTC, Seamless Casing
8-1/2"	20,000'	16,800'	7", 32 ppf, P-110, BTC, Seamless Casing
Tie Back	4800'	Surface	13-3/8", 72 ppf, N-80, Vam Top, Seamless Casing

Wellhead Information	
Flange Size	Pressure Test (psi)
30" SOW x API 30", 2000	Weld Test Pressure = 500 psi
30" API 2000 BOP	BOP and 30" Casing Test Pressure = 1000 psi
20" SOW x API 20-3/4", 3000	Weld Test Pressure 1000 psi
20-3/4" API 3000 BOP	BOP and 20" Casing Test Pressure = 1500 psi
13-3/8" SOW x ANSI 900	BOP and 13-3/8" Tieback Test Pressure = 2000 psi

Project Statement

Develop a detailed plan and cost estimated for the construction of a 20'000 foot well envisioned for future Enhanced Geothermal Systems application in Lake County, California. The plan shall include a detailed procedure, timeline, well schematic, days vs depth plot and cost estimate for drilling the well.

General Assumptions

A general assumption has been made that the well can be drilled with existing equipment and technologies currently used in the oil and gas and geothermal drilling industry. In addition the drilling program has been developed following current practices and procedures used for drilling geothermal wells.

The program and cost estimate has been developed for drilling the well and does not include time or costs associated with road and location construction and equipment mobilization. As a specific site has not been determined for the location of the well, very general assumptions about subsurface conditions have been developed to generate the base case EGS drilling program and cost estimate.

It is the intent that the program and cost estimate for the 20,000 foot EGS well is to serve as a base case to which alternative designs, procedures and technologies can be compared.

Formation Pressure and Temperature

For this exercise the formation pressure has been assumed to be normally pressured with a fresh water gradient from surface to 20,000 feet. The temperature profile has been assumed to be 50°F at surface with 2.60°F / 100 ft giving a bottom hole temperature at 20,000 feet of 570°F.

Although severe lost circulation is commonly encountered while drilling hydrothermal systems, the EGS well is intended to be a dry hole and therefore any impact of encountering lost circulation while drilling has been excluded.

Drill Bit Performance

The table below summarizes the rate of penetration, daily drilling rate and bit life expected for each hole section. Rates of penetration are provided in feet per hour as captured in bit records which includes time required for making connections. Daily drilling rates measured in feet per day represent the average feet drilled per day over an interval and include all time for drilling, circulating, tripping, handling BHA's and routine rig service.

Hole Size (inches)	ROP (ft/hr)	Drilling Rate (ft/day)	Bit Life (ft)
26” Bit / 36” Opener	12 ft/hr	110 ft/day	500 ft
26 Inch	15 ft/hr	275 ft/day	1500 ft
17-1/2 inch	18 ft/hr	275 ft/day	2000 ft
12-1/4 inch	12.5 ft/hr	205 ft/day	1500 ft
8-1/2 inch	12 ft/hr	150 ft/day	1000 ft

Rig Specifications and Performance
The primary rig equipment and specification required to drill the 20,000 foot EGS well are listed below.

- 3000 HP Drawworks
- 1.5 million pound Mast Capacity
- 650 ton, 1200 HP Top Drive
- (3) 1600 HP Mud Pumps Capable of pumping 1400 gpm
- 500 ton Casing Elevators
- 30”, 2000 psi Annular BOP
- 20-3/4”, 3000 psi BOP

It has been assumed for the time distribution that the rig will trip drill pipe at an average of 1000 feet per hour pulling out of the hole and running back in the hole and does not include handling BHA components.

Time Distribution
The well has been divided into the following six phases for the detailed task analysis and time distribution evaluation.

- PHASE (I): SURFACE: (36” Hole to 500’ with 30” Casing)
- PHASE (II): INTERMEDIATE 1: (26” Hole to 5000’ with 20” Casing)
- PHASE (III): PRODUCTION LINER 1: (17-1/2” Hole to 10,000’ with 13-5/8” Casing)
- PHASE (IV): PRODUCTION LINER 2: (12-1/4” Hole to 17,000’ with 9-5/8” Casing)
- PHASE (V): PRODUCTION LINER 3: (8-1/2” Hole to 20,000’ with 7” Casing)
- PHASE (VI): PRODUCTION TIEBACK: (13-3/8” Casing)

To simplify the analysis, each phase has been divided in three activities with three to nine tasks as shown in the flow chart below.

Drilling System Parameters by Interval

The remainder of this section describes BHA composition, hydraulic program, mud program and cementing program by drilling interval.

<u>PHASE (I): SURFACE: (36” Hole to 500’ with 30” Casing)</u>

Bit & Hydraulics Program		Mud Program	
Bit Type	26” / 36” Opener	Mud Weight	8.6 – 9.0 ppg
Nozzles	4 x 22	Mud Type	
Pump Rate	1200 - 1400 gpm	Funnel Vis	
RPM	80 - 120	PV / YP	
WOB K-lbs	50- 80	Filtrate	
Spud BHA 26” Bit with 36” Hole Opener	26” BIT, 36” HOLE OPENER, LOW SPEED MUD MOTOR, 36” STABILIZER, XO, 6-5/8” HWDP		
Drilling BHA 26” Bit with 36” Hole Opener	26” BIT, 36” HOLE OPENER, LOW SPEED MUD MOTOR, 36” STABILIZER, 12” SHOCK SUB, 6 x 11” DRILL COLLARS, XO, 3 x 9-1/2” DC, XO, 6-5/8” HWDP		

Cementing Table – 36” Open Hole, 30” Casing		
Slurry Details	Lead	Tail
Spacer	10 bbl Fresh Water	
Cementing method	Inner String	
Weight (ppg)	14.0 ppg	
Design	500’ to Surface	
Excess	50%	
Approximate Volume (bbl)	350 bbl	
Cement	Class G	
Pump lead cement until full weight cement observed at surface, switch over and displace		

PHASE (II): INTERMEDIATE 1: (26” Hole to 5000’ with 20” Casing)

The 26” hole section will be drilled with a vertical controlled drilling system.

Bit & Hydraulics Program		Mud Program	
Bit Type	TCI	Mud Weight	8.6 – 9.0 ppg
Nozzles	4 x 22	Mud Type	
Pump Rate	1200 - 1400 gpm	Funnel Vis	
RPM	120 – 160	PV / YP	
WOB K-lbs	50 - 80	Filtrate	
Drilling BHA	26” BIT, VERTICAL DRILLING MOTOR SYSTEM, PULSAR SUB, 12” SHOCK SUB, 25-1/2” STABILIZER, 6 x 11” DRILL COLLARS, XO, 3 x 9-1/2” DC, JARS, 2 x 9-1/2” XO, 15 x 6-5/8” HWDP		
Wiper Trip BHA	26” BIT, 25-1/2” NEAR BIT STABILIZER, 3 x 11” DRILL COLLARS, XO, 3 x 9-1/2” DC, JARS, 2 x 9-1/2” XO, 15 x 6-5/8” HWDP		

Cementing Table – 26” Open Hole, 20” Casing		
Slurry Details	Lead	Tail
Spacer	10 bbls of fresh water / 100 bbls flow check / 10 bbls fresh water	
Cementing method	Inner String	Inner String
Weight (ppg)	13.5 ppg	15.0 ppg
Design	5000’ to surface	400’ Plus 40’ Shoe
Excess	50% in open hole	50% in open hole
Approximate Volume (bbl)	1840 bbl	190 bbl
Cement	Class G with 40% Silica Flour	Class G with 40%
Displace with mud and pump theoretical displacement only.		

PHASE (III): PRODUCTION LINER 1: (17-1/2” Hole to 10,000’ with 13-5/8” Casing)

The 17-1/2” hole section will be drilled with a vertical controlled drilling system.

Bit & Hydraulics Program		Mud Program	
Bit Type	TCI	Mud Weight	8.6 – 9.0 ppg
Nozzles	3 x 20	Mud Type	
Pump Rate	900 - 1100 gpm	Funnel Vis	
RPM	120 – 160	PV / YP	
WOB K-lbs	50 - 80	Filtrate	

Drilling BHA	17-1/2” BIT, 9-1/2” VERTICAL DRILLING MOTOR SYSTEM, PULSAR SUB, 10” SHOCK SUB, 17-1/4” STABILIZER, 6 x 9-1/2” DRILL COLLARS, XO, 9 x 8” DC, JARS, 2 x 9-1/2” XO, 15 x 6-5/8” HWDP
Wiper Trip BHA	17-1/2” BIT, 17-1/4” NEAR BIT STABILIZER, 3 x 9-1/2” DRILL COLLARS, XO, 3 x 8” DC, JARS, 2 x 8” XO, 15 x 6-5/8” HWDP
17-1/2” Clean Out BHA	17-1/2” BIT, BIT SUB, XO, 3 x 8” DC, JARS, 2 x 8” XO, 15 X 6-5/8” HWDP

Cementing Table – 17-1/2” Open Hole, 13-5/8” Liner		
Slurry Details	Lead	Tail
Spacer	10 bbls of fresh water / 100 bbls weighted spacer / 10 bbls fresh water	
Cementing method	Liner	Liner
Weight (ppg)	13.5 ppg	15.0 ppg
Design	10,000’ to 20” shoe at 5000’ plus 200’ lap	400’ Plus 120’ Shoe Track
Excess	50% in open hole	50% in open hole
Approximate Volume (bbl)	840 bbl	100 bbl
Cement	Class G with 40% Silica Flour	Class G with 40%
Displace with mud and bump plug.		

PHASE (IV): PRODUCTION LINER 2: (12-1/4” Hole to 17,000’ with 9-5/8” Casing)

The 12-1/4” hole section will be drilled with a vertical controlled drilling system.

Bit & Hydraulics Program		Mud Program	
Bit Type	TCI	Mud Weight	8.6 – 9.0 ppg
Nozzles	3 x 22	Mud Type	
Pump Rate	700 - 900 gpm	Funnel Vis	
RPM	120 – 160	PV / YP	
WOB K-lbs	45 - 60	Filtrate	
Drilling BHA	12-1/4” BIT, 9-1/2” VERTICAL DRILLING MOTOR SYSTEM, PULSAR SUB, 8” SHOCK SUB, 12” STABILIZER, XO, 15 x 8” DC, JARS, 2 x 8” XO, 15 x 5” HWDP		
Wiper Trip BHA	12-1/4” BIT, 12” NEAR BIT STABILIZER, 3 x 8” DRILL COLLARS, JARS, 2 x 8” XO, 15 X 5” HWDP		
12-1/4” Clean Out BHA	12-1/4” BIT, BIT SUB, XO, 3 x 8” DC, JARS, 2 x 8” XO, 15 X 5” HWDP		

Cementing Table – 12-1/4” Open Hole, 9-5/8” Liner		
Slurry Details	Lead	Tail
Spacer	10 bbls of fresh water / 50 bbls weighted spacer / 10 bbls fresh water	
Cementing method	Liner	Liner
Weight (ppg)	13.5 ppg	15.0 ppg
Design	17,000’ to 13-5/8” shoe at 10,000’ plus 200’ lap	400’ Plus 120’ Shoe Track
Excess	50% in open hole	50% in open hole
Approximate Volume (bbl)	560 bbl	45 bbl
Cement	Class G with 40% Silica Flour	Class G with 40%
Displace with mud and bump plug.		

PHASE (V): PRODUCTION LINER 3: (8-1/2” Hole to 20,000’ with 7” Casing)

The 8” hole section will be drilled with a vertical controlled drilling system.

Bit & Hydraulics Program		Mud Program	
Bit Type	TCI	Mud Weight	8.6 – 9.0 ppg
Nozzles	3 x 22	Mud Type	
Pump Rate	700 - 900 gpm	Funnel Vis	
RPM	120 – 160	PV / YP	
WOB K-lbs	25 - 40	Filtrate	
Drilling BHA	8-1/2” BIT, 6-3/4” VERTICAL DRILLING MOTOR SYSTEM, PULSAR SUB, 7” SHOCK SUB, 8-1/4” STABILIZER, XO, 15 x 6-1/2” DC, JARS, 2 x 6-1/2” XO, 15 x 5” HWDP		
Wiper Trip BHA	8-1/2” BIT, 8-1/4” NEAR BIT STABILIZER, 6 x 6-1/2” DRILL COLLARS, JARS, 2 x 6-1/2” XO, 15 X 5” HWDP		
8-1/2” Clean Out BHA	8-1/2” BIT, BIT SUB, 6 x 6-1/2” DC, JARS, 2 x 6-1/2”, 15 X 5” HWDP		
6” Clean Out BHA	6” BIT, BIT SUB, 6 x 4-3/4” DC, JARS, 2 x 4-3/4”, 15 X 3-1/2” HWDP		

Cementing Table – 8-1/2" Open Hole, 7" Liner		
Slurry Details	Lead	Tail
Spacer	10 bbls of fresh water / 25 bbls weighted spacer / 10 bbls fresh water	
Cementing method	Liner	Liner
Weight (ppg)	13.5 ppg	15.0 ppg
Design	20,000' to 9-5/8" shoe at 17,000' plus 200' lap	400' Plus 120' Shoe Track
Excess	50% in open hole	50% in open hole
Approximate Volume (bbl)	95 bbl	20 bbl
Cement	Class G with 40% Silica Flour	Class G with 40%
Displace with mud and bump plug.		

PHASE (VI): PRODUCTION TIEBACK: (13-3/8" Casing)

BHA	
12-1/4" Clean Out BHA	12-1/4" BIT, BIT SUB, 3 x 8" DC, JARS, 2 x 8", 15 X 5" HWDP

Cementing Table – 13-3/8" Production Tieback		
Slurry Details	Lead	Tail
Spacer		10 bbls of fresh water
Cementing method		Conventional
Weight (ppg)		16.0 ppg
Design		4800' to surface plus 80' shoe track
Excess		30%
Approximate Volume (bbl)		970 bbl
Cement		Class G with 40% Silica Flour
Cement with bottom and top plug. Displace with mud and bump plug.		

B.2 Drilling Script

The following script gives a step-by-step procedure for drilling and completing the prototype well.

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3883 Airway Drive
Suite 340
Santa Rosa, CA 95403
TELEPHONE: (707) 523-2960

TASK ANALYSIS

NAME OF OPERATOR:	**SANDIA NATIONAL LABORATORIES**
FIELD NAME:	Clear Lake, CA
Well Name:	20,000-ft EGS Well
Estimator / Engineer:	Robert J. Swanson
Date:	August 13, 2008

SUMMARY

Total Days	**141**
Phase I: Surface	**7.5**
(36" Hole to 500' with 30" Casing)	
Drilling	3.6
Casing and Logging	3.9
Phase II: Intermediate 1	**23.1**
(26" Hole to 5000' with 20" Casing)	
Drilling	16
Casing and Logging	7
Phase III: Production Liner 1	**24.5**
(17-1/2" Hole to 10,000' with 13-5/8" Casing)	
Drilling	16.3
Casing and Logging	8.3
Phase IV: Production Liner 2	**42.8**
(12-1/4" Hole to 17,000' with 9-5/8" Casing)	
Drilling	34.2
Casing and Logging	8.7
Phase V: Production Liner 3	**33.5**
(8-1/2" Hole to 20,000' with 7" Casing)	
Drilling	19.7
Casing and Logging	13.9
Phase VI: Production Tie-Back	**9.6**
(13-3/8" Casing)	
Casing	9.6

Date Printed:8/14/2008 DaysSummary

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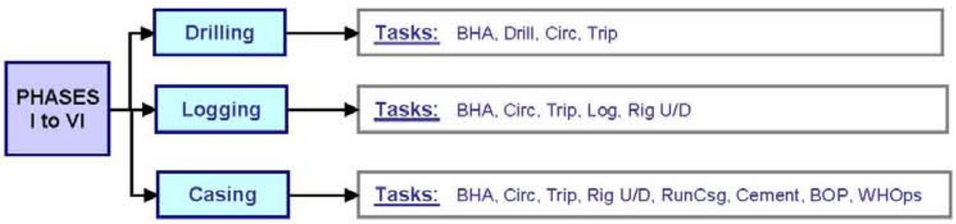
TASK ANALYSIS

OPERATOR NAME: **SANDIA NATIONAL LABORATORIES**
FIELD NAME: Clear Lake, CA — Estimator / Engineer: Robert J. Swanson
Well Name: 20,000-ft EGS Well — Date: August 13, 2008

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days
				3,386	141.0



Phase I: Surface			(36" Hole to 500' with 30" Casing)	180	7.5
1 Surface	**DRILLING OPERATIONS**			**86**	**3.6**
1 Surface	Drilling	BHA	1. Make up 26" bit and 36" hole opener on mud motor.	6	0.3
1 Surface	Drilling	BHA	2. Pick up 36" stabilizer and cross over to 6-5/8" HWDP.	4	0.2
1 Surface	Drilling	Drill	3. Drill and open 36" hole with motor and HWDP from 80' to 240'.	13	0.5
1 Surface	Drilling	Circ	4. Circulate	1	0.0
1 Surface	Drilling	BHA	5. Trip out of the hole and stand back 6-5/8" HWDP.	2	0.1
1 Surface	Drilling	BHA	6. Pick up (6) 11" drill collars and cross over to 6-5/8" HWDP.	8	0.3
1 Surface	Drilling	Drill	7. Drill and open 36" hole from 240' to 320'.	7	0.3
1 Surface	Drilling	Circ	8. Circulate	1	0.0
1 Surface	Drilling	BHA	9. Stand back 6-5/8" HWDP	2	0.1
1 Surface	Drilling	BHA	10. Pick up (3) 9-1/2" drill collars and cross over to 6-5/8" HWDP.	6	0.3
1 Surface	Drilling	Drill	11. Drill and open 36" hole from 320' to 500'.	15	0.6
1 Surface	Drilling	Circ	12. Circulate.	1	0.0
1 Surface	Drilling	Trip	13. Make a wiper trip to 320'.	4	0.2
1 Surface	Drilling	Circ	14. Circulate	1	0.0
1 Surface	Drilling	Trip	15. Trip out of the hole.	2	0.1
1 Surface	Drilling	BHA	16. Stand back HWDP and drill collars.	7	0.3
1 Surface	Drilling	BHA	17. Break out and lay down 36" stabilizer, mud motor, 36" hole opener and 26" bit.	6	0.3
1 Surface	**LOGGING OPERATIONS**			**7**	**0.3**
1 Surface	Logging	RigU/D	1. Rig up logging equipment.	2	0.1
1 Surface	Logging	Log	2. Run formation evaluation and caliper log.	3	0.1
1 Surface	Logging	RigU/D	3. Rig down logging equipment.	2	0.1
1 Surface	**CASING OPERATIONS**			**87**	**3.6**
1 Surface	Casing	RigU/D	1. Rig up casing running equipment.	3	0.1
1 Surface	Casing	RunCsng	2. Run 30", 1" wall, 310 ppf, X-56, Dril Quip – Quick Stab, line pipe to 500' and set	12	0.5
1 Surface	Casing	RigU/D	3. Rig up false floor for inner string cement job.	2	0.1
1 Surface	Casing	Trip	4. Pick up and run in the hole with 6-5/8" drill pipe and stab into the 30" float shoe.	2	0.1
1 Surface	Casing	RigU/D	5. Rig up cementing head on drill pipe.	1	0.0
1 Surface	Casing	Circ	6. Circulate and condition hole for cementing.	2	0.1
1 Surface	Casing	Cement	7. Mix, pump and displace cement per Table 1.	2	0.1
1 Surface	Casing	RigU/D	8. Rig down cementing equipment.	1	0.0
1 Surface	Casing	Trip	9. Trip out of the hole and stand back the 6-5/8" drill pipe.	3	0.1
1 Surface	Casing	Cement	10. Wait on cement for initial set to 500 psi compressive strength.	12	0.5
1 Surface	Casing	WH Ops	11. Slack off on casing.	1	0.0
1 Surface	Casing	WH Ops	12. Cut and lift 40" conductor.	2	0.1
1 Surface	Casing	WH Ops	13. Cut and dress 30" casing.	6	0.3
1 Surface	Casing	WH Ops	14. Weld on 30" SOW x API 30", 2000 casing head.	6	0.3

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TASK ANALYSIS

OPERATOR NAME: **SANDIA NATIONAL LABORATORIES**

FIELD NAME:	Clear Lake, CA	Estimator / Engineer:	Robert J. Swanson
Well Name:	20,000-ft EGS Well	Date:	August 13, 2008

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days
				3,386	141.0
1 Surface	Casing	WH Ops	15. Pressure test weld to 500 psi.	1	0.0
1 Surface	Casing	BOP	16. Nipple up 30" BOP with blind ram and annular and connect to flow line.	28	1.2
1 Surface	Casing	BOP	17. Function test and pressure test BOP and 30" casing to 250 psi low and 1000 psi	3	0.1
Phase II: Intermediate 1			**(26" Hole to 5000' with 20" Casing)**	**554**	**23.1**
2 INT-1	**DRILLING OPERATIONS**			**385**	**16.0**
2 INT-1	Drilling	BHA	1. Make up 26" bit and vertical drilling BHA.	8	0.3
2 INT-1	Drilling	Trip	2. Trip in hole to the top of 20" casing shoe at 500'.	2	0.1
2 INT-1	Drilling	Drill	3. Drill out casing shoe.	2	0.1
2 INT-1	Drilling	Drill	4. Drill 26" hole from 500' to 510'.	1	0.0
2 INT-1	Drilling	Circ	5. Circulate.	1	0.0
2 INT-1	Drilling	Circ	6. Perform leak off test.	3	0.1
2 INT-1	Drilling	Drill	7. Drill 26" hole from 510' to 1250'	49	2.0
2 INT-1	Drilling	Circ	8. Circulate.	1	0.0
2 INT-1	Drilling	Trip	9. Make a wiper trip to the 30" casing shoe and back to bottom.	4	0.2
2 INT-1	Drilling	Drill	10. Drill 26" hole from 1250' to 2000'	50	2.1
2 INT-1	Drilling	Circ	11. Circulate.	1	0.0
2 INT-1	Drilling	Trip	12. Trip out of the hole for a new bit.	2	0.1
2 INT-1	Drilling	BHA	13. Stand back BHA.	4	0.2
2 INT-1	Drilling	BHA	14. Make up new 26" bit and run in the hole with BHA.	4	0.2
2 INT-1	Drilling	Trip	15. Trip in hole to 2000'	2	0.1
2 INT-1	Drilling	Drill	16. Drill 26" hole from 2000' to 2750'	50	2.1
2 INT-1	Drilling	Circ	17. Circulate.	1	0.0
2 INT-1	Drilling	Trip	18. Make a wiper trip to the 30" casing shoe and back to bottom.	4	0.2
2 INT-1	Drilling	Drill	19. Drill 26" hole from 2750' to 3500'.	50	2.1
2 INT-1	Drilling	Circ	20. Circulate.	1	0.0
2 INT-1	Drilling	Trip	21. Trip out of the hole for a new bit.	4	0.2
2 INT-1	Drilling	BHA	22. Stand back BHA.	4	0.2
2 INT-1	Drilling	BHA	23. Make up new 26" bit and run in the hole with BHA.	4	0.2
2 INT-1	Drilling	Trip	24. Trip in hole to 3500'	4	0.2
2 INT-1	Drilling	Drill	25. Drill 26" hole from 3500' to 4250'	50	2.1
2 INT-1	Drilling	Circ	26. Circulate.	1	0.0
2 INT-1	Drilling	Trip	27. Make a wiper trip to the 30" casing shoe and back to bottom.	6	0.3
2 INT-1	Drilling	Drill	28. Drill 26" hole from 4250' to 5000'	50	2.1
2 INT-1	Drilling	Circ	29. Circulate.	1	0.0
2 INT-1	Drilling	Trip	30. Make a wiper trip to the 30" casing shoe and back to bottom.	7	0.3
2 INT-1	Drilling	Circ	31. Circulate.	1	0.0
2 INT-1	Drilling	Trip	32. Trip out of the hole.	5	0.2
2 INT-1	Drilling	BHA	33. Stand back BHA.	4	0.2
2 INT-1	Drilling	BHA	34. Lay down vertical drilling motor and equipment.	4	0.2
2 INT-1	**LOGGING OPERATIONS**			**34**	**1.4**
2 INT-1	Logging	RigU/D	1. Rig up logging equipment.	1	0.0
2 INT-1	Logging	Log	2. Run formation evaluation logs and caliper log. (2 runs).	16	0.7
2 INT-1	Logging	RigU/D	3. Rig down logging equipment.	1	0.0
2 INT-1	Logging	BHA	4. Make up 26" bit on wiper trip BHA and RIH.	4	0.2
2 INT-1	Logging	Trip	5. Trip in hole to 5000'.	4	0.2
2 INT-1	Logging	Circ	6. Circulate hole clean.	1	0.0
2 INT-1	Logging	Trip	7. Trip out of hole.	4	0.2
2 INT-1	Logging	BHA	8. Stand back BHA.	3	0.1
2 INT-1	**CASING OPERATIONS**			**135**	**5.6**
2 INT-1	Casing	RigU/D	1. Rig up casing running equipment.	3	0.1

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TASK ANALYSIS

OPERATOR NAME: **SANDIA NATIONAL LABORATORIES**

FIELD NAME: Clear Lake, CA — Estimator / Engineer: Robert J. Swanson

Well Name: 20,000-ft EGS Well — Date: August 13, 2008

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days
				3,386	141.0
2 INT-1	Casing	RunCsng	2. Run 20", 169 ppf, N-80, BTC casing to 5000' and set in slips.	36	1.5
2 INT-1	Casing	RigU/D	3. Rig up false floor for inner string cement job.	2	0.1
2 INT-1	Casing	Trip	4. Pick up and run in the hole with 6-5/8" drill pipe and stab into the 20" float shoe.	7	0.3
2 INT-1	Casing	RigU/D	5. Rig up cementing head on drill pipe.	1	0.0
2 INT-1	Casing	Circ	6. Circulate and condition hole for cementing.	2	0.1
2 INT-1	Casing	Cement	7. Mix, pump and displace cement per Table 2.	7	0.3
2 INT-1	Casing	RigU/D	8. Rig down cementing equipment.	1	0.0
2 INT-1	Casing	Trip	9. Trip out of the hole and stand back the 6-5/8" drill pipe.	5	0.2
2 INT-1	Casing	Cement	10. Wait on cement for initial set to 500 psi compressive strength.	12	0.5
2 INT-1	Casing	WH Ops	11. Slack off on casing.	1	0.0
2 INT-1	Casing	WH Ops	12. Lift BOP, rough cut 20" casing and nipple down BOP	5	0.2
2 INT-1	Casing	WH Ops	13. Cut off 30" casing head.	3	0.1
2 INT-1	Casing	WH Ops	14. Cut and dress 20" casing.	3	0.1
2 INT-1	Casing	WH Ops	15. Weld on 20" SOW x API 20-3/4", 3000 casing head.	18	0.8
2 INT-1	Casing	WH Ops	16. Pressure test weld to 1000 psi.	1	0.0
2 INT-1	Casing	BOP	17. Nipple up 20-3/4", 3000 psi BOP and connect to flow line.	18	0.8
2 INT-1	Casing	BOP	18. Function test and pressure test BOP and 20" casing to 250 psi low and 1500 psi	4	0.2
2 INT-1	Casing	BHA	19. Lay down 11" drill collars.	6	0.3
Phase III: Production Liner 1			**(17-1/2" Hole to 10,000' with 13-5/8" Casing)**	**589**	**24.5**
3 PROD-1	**DRILLING OPERATIONS**			**391**	**16.3**
3 PROD-1	Drilling	BHA	1. Make up 17-1/2" bit on vertical drilling BHA.	7	0.3
3 PROD-1	Drilling	Trip	2. Trip in hole to the top of the 20" float collar at 4960'.	5	0.2
3 PROD-1	Drilling	Drill	3. Drill out float collar, shoe track and float shoe.	3	0.1
3 PROD-1	Drilling	Drill	4. Drill 17-1/2" hole from 5000' to 5010'.	1	0.0
3 PROD-1	Drilling	Circ	5. Circulate.	1	0.0
3 PROD-1	Drilling	Circ	6. Perform leak off test.	3	0.1
3 PROD-1	Drilling	Drill	7. Drill 17-1/2" hole from 5010' to 6000'	56	2.3
3 PROD-1	Drilling	Circ	8. Circulate.	1	0.0
3 PROD-1	Drilling	Trip	9. Make a wiper trip to the 20" casing shoe and back to bottom.	2	0.1
3 PROD-1	Drilling	Drill	10. Drill 17-1/2" hole from 6000' to 7000'	56	2.3
3 PROD-1	Drilling	Circ	11. Circulate.	1	0.0
3 PROD-1	Drilling	Trip	12. Trip out of the hole for a new bit.	7	0.3
3 PROD-1	Drilling	BHA	13. Stand back BHA.	4	0.2
3 PROD-1	Drilling	BHA	14. Make up new 17-1/2" bit and run in the hole with BHA.	4	0.2
3 PROD-1	Drilling	Trip	15. Trip in hole to 7000'	7	0.3
3 PROD-1	Drilling	Drill	16. Drill 17-1/2" hole from 7000' to 8000'	56	2.3
3 PROD-1	Drilling	Circ	17. Circulate.	1	0.0
3 PROD-1	Drilling	Trip	18. Make a wiper trip to the 20" casing shoe and back to bottom.	6	0.3
3 PROD-1	Drilling	Drill	19. Drill 17-1/2" hole from 8000' to 9000'.	56	2.3
3 PROD-1	Drilling	Circ	20. Circulate.	1	0.0
3 PROD-1	Drilling	Trip	21. Trip out of the hole for a new bit.	9	0.4
3 PROD-1	Drilling	BHA	22. Stand back BHA.	4	0.2
3 PROD-1	Drilling	BHA	23. Make up new 17-1/2" bit and run in the hole with BHA.	4	0.2
3 PROD-1	Drilling	Trip	24. Trip in hole to 9000'	9	0.4
3 PROD-1	Drilling	Drill	25. Drill 17-1/2" hole from 9000' to 10,000'	56	2.3
3 PROD-1	Drilling	Circ	26. Circulate.	1	0.0
3 PROD-1	Drilling	Trip	27. Make a wiper trip to the 20" casing shoe and back to bottom.	10	0.4
3 PROD-1	Drilling	Circ	28. Circulate.	2	0.1
3 PROD-1	Drilling	Trip	29. Trip out of the hole.	10	0.4
3 PROD-1	Drilling	BHA	30. Stand back BHA.	4	0.2

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TASK ANALYSIS

OPERATOR NAME: **SANDIA NATIONAL LABORATORIES**

FIELD NAME:	Clear Lake, CA	Estimator / Engineer:	Robert J. Swanson
Well Name:	20,000-ft EGS Well	Date:	August 13, 2008

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days
				3,386	141.0
3 PROD-1	Drilling	BHA	31. Lay down vertical drilling motor and equipment.	4	0.2
3 PROD-1	**LOGGING OPERATIONS**			**60**	**2.5**
3 PROD-1	Logging	RigU/D	1. Rig up logging equipment.	1	0.0
3 PROD-1	Logging	Log	2. Run formation evaluation logs and caliper log, (3 runs).	30	1.3
3 PROD-1	Logging	RigU/D	3. Rig down logging equipment.	1	0.0
3 PROD-1	Logging	BHA	4. Make up 17-1/2" bit on wiper trip BHA and RIH.	4	0.2
3 PROD-1	Logging	Trip	5. Trip in hole to 10,000'.	9	0.4
3 PROD-1	Logging	Circ	6. Circulate hole clean.	2	0.1
3 PROD-1	Logging	Trip	7. Trip out of hole.	9	0.4
3 PROD-1	Logging	BHA	8. Stand back BHA.	4	0.2
3 PROD-1	**CASING OPERATIONS**			**138**	**5.8**
3 PROD-1	Casing	RigU/D	1. Rig up casing running equipment.	3	0.1
3 PROD-1	Casing	RunCsng	2. Run 5200' of 13-5/8", 88.2 ppf, P-110, BTC casing.	16	0.7
3 PROD-1	Casing	RunCsng	3. Make up liner hanger assembly to 13-5/8" casing.	2	0.1
3 PROD-1	Casing	RigU/D	4. Rig down casing running equipment.	2	0.1
3 PROD-1	Casing	RunCsng	5. Run in hole with 13-5/8" liner on 6-5/8" drill pipe to 10,000'.	12	0.5
3 PROD-1	Casing	RunCsng	6. Set liner hanger.	2	0.1
3 PROD-1	Casing	RunCsng	7. Release from running tool.	1	0.0
3 PROD-1	Casing	RigU/D	8. Rig up cementing head on drill pipe.	1	0.0
3 PROD-1	Casing	Circ	9. Circulate and condition hole for cementing.	2	0.1
3 PROD-1	Casing	Cement	10. Mix, pump and displace cement per Table 3.	8	0.3
3 PROD-1	Casing	Trip	11. Pull running tool out of liner hanger and pick up 90'.	2	0.1
3 PROD-1	Casing	Circ	12. Circulate excess cement to surface.	3	0.1
3 PROD-1	Casing	Trip	13. Trip out of the hole.	5	0.2
3 PROD-1	Casing	RunCsng	14. Lay down liner running tools.	2	0.1
3 PROD-1	Casing	BHA	15. Pick up 17-1/2" clean out BHA.	4	0.2
3 PROD-1	Casing	Trip	16. Trip in the hole to the top of cement at 4700'.	5	0.2
3 PROD-1	Casing	Cement	17. Wait on cement for initial set to 500 psi compressive strength.	6	0.3
3 PROD-1	Casing	Cement	18. Clean out cement in the 20" casing to the top of the liner hanger.	3	0.1
3 PROD-1	Casing	Circ	19. Circulate hole clean.	1	0.0
3 PROD-1	Casing	BOP	20. Pressure test the liner lap to 1000 psi surface pressure.	1	0.0
3 PROD-1	Casing	Trip	21. Trip out of the hole.	5	0.2
3 PROD-1	Casing	BHA	22. Stand back BHA.	4	0.2
3 PROD-1	Casing	BHA	23. Lay down 9-1/2" drill collars and 6-5/8" HWDP.	8	0.3
3 PROD-1	Casing	BHA	24. Lay down 6-5/8" drill pipe.	18	0.8
3 PROD-1	Casing	BHA	25. Pick up 5-1/2" HWDP and 5-1/2" drill pipe.	22	0.9
Phase IV: Production Liner 2			**(12-1/4" Hole to 17,000' with 9-5/8" Casing)**	**1,028**	**42.8**
4 PROD-2	**DRILLING OPERATIONS**			**820**	**34.2**
4 PROD-2	Drilling	BHA	1. Make up 12-1/4" clean out BHA.	4	0.2
4 PROD-2	Drilling	Trip	2. Trip in the hole to the top of the 13-5/8" liner hanger.	5	0.2
4 PROD-2	Drilling	Drill	3. Drill out pack off bushing.	2	0.1
4 PROD-2	Drilling	Circ	4. Circulate the hole clean.	2	0.1
4 PROD-2	Drilling	Trip	5. Trip in the hole to the top of the landing collar at 9880'.	5	0.2
4 PROD-2	Casing	BOP	6. Pressure test the liner to 1000 psi.	1	0.0
4 PROD-2	Drilling	Drill	7. Drill out the landing collar, 40' of cement, float collar, 80' of cement and float sho	4	0.2
4 PROD-2	Drilling	Drill	8. Drill 12-1/4" hole from 10,000' to 10,010.	1	0.0
4 PROD-2	Drilling	Circ	9. Circulate.	2	0.1
4 PROD-2	Drilling	Circ	10. Perform leak off test.	3	0.1
4 PROD-2	Drilling	Trip	11. Trip out of hole.	10	0.4
4 PROD-2	Drilling	BHA	12. Stand back BHA.	4	0.2

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GEOTHERMAL CONSULTING AND DRILLING

TASK ANALYSIS

OPERATOR NAME: **SANDIA NATIONAL LABORATORIES**

FIELD NAME: Clear Lake, CA

Well Name: 20,000-ft EGS Well

Estimator / Engineer: Robert J. Swanson

Date: August 13, 2008

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days
				3,386	141.0
4 PROD-2	Drilling	BHA	13. Make up 12-1/4" bit on drilling BHA with vertical drilling system.	4	0.2
4 PROD-2	Drilling	Trip	14. Trip in hole to 10,010'.	10	0.4
4 PROD-2	Drilling	Drill	15. Drill 12-1/4" hole from 10,010' to 10,750.	60	2.5
4 PROD-2	Drilling	Circ	16. Circulate.	2	0.1
4 PROD-2	Drilling	Trip	17. Make a wiper trip to the 13-5/8" casing shoe.	2	0.1
4 PROD-2	Drilling	Drill	18. Drill 12-1/4" hole from 10,750' to 11,500'	60	2.5
4 PROD-2	Drilling	Circ	19. Circulate.	2	0.1
4 PROD-2	Drilling	Trip	20. Trip out of the hole for a new bit.	12	0.5
4 PROD-2	Drilling	BHA	21. Stand back BHA.	4	0.2
4 PROD-2	Drilling	BHA	22. Make up new 12-1/4" bit and run in the hole with BHA.	4	0.2
4 PROD-2	Drilling	Trip	23. Trip in hole to 11,500'	12	0.5
4 PROD-2	Drilling	Drill	24. Drill 12-1/4" hole from 11,500' to 12,250'	60	2.5
4 PROD-2	Drilling	Circ	25. Circulate.	2	0.1
4 PROD-2	Drilling	Trip	26. Make a wiper trip to the 13-5/8" casing shoe and back to bottom.	4	0.2
4 PROD-2	Drilling	Drill	27. Drill 12-1/4" hole from 12,250' to 13,000'.	60	2.5
4 PROD-2	Drilling	Circ	28. Circulate.	2	0.1
4 PROD-2	Drilling	Trip	29. Trip out of the hole for a new bit.	13	0.5
4 PROD-2	Drilling	BHA	30. Stand back BHA.	4	0.2
4 PROD-2	Drilling	BHA	31. Make up new 12-1/4" bit and run in the hole with BHA.	4	0.2
4 PROD-2	Drilling	Trip	32. Trip in hole to 13,000'	13	0.5
4 PROD-2	Drilling	Drill	33. Drill 12-1/4" hole from 13,000' to 13,750'	60	2.5
4 PROD-2	Drilling	Circ	34. Circulate.	2	0.1
4 PROD-2	Drilling	Trip	35. Make a wiper trip to the 13-5/8" casing shoe and back to bottom.	6	0.3
4 PROD-2	Drilling	Drill	36. Drill 12-1/4" hole from 13,750' to 14,500'	60	2.5
4 PROD-2	Drilling	Circ	37. Circulate.	2	0.1
4 PROD-2	Drilling	Trip	38. Trip out of the hole for a new bit.	15	0.6
4 PROD-2	Drilling	BHA	39. Stand back BHA.	4	0.2
4 PROD-2	Drilling	BHA	40. Make up new 12-1/4" bit and run in the hole with BHA.	4	0.2
4 PROD-2	Drilling	Trip	41. Trip in hole to 14,500'	15	0.6
4 PROD-2	Drilling	Drill	42. Drill 12-1/4" hole from 14,500' to 15,250'	60	2.5
4 PROD-2	Drilling	Circ	43. Circulate.	3	0.1
4 PROD-2	Drilling	Trip	44. Make a wiper trip to the 13-5/8" casing shoe and back to bottom.	8	0.3
4 PROD-2	Drilling	Drill	45. Drill 12-1/4" hole from 15,250' to 16,000'.	60	2.5
4 PROD-2	Drilling	Circ	46. Circulate.	3	0.1
4 PROD-2	Drilling	Trip	47. Trip out of the hole for a new bit.	16	0.7
4 PROD-2	Drilling	BHA	48. Stand back BHA.	4	0.2
4 PROD-2	Drilling	BHA	49. Make up new 12-1/4" bit and run in the hole with BHA.	4	0.2
4 PROD-2	Drilling	Trip	50. Trip in hole to 16,000'	16	0.7
4 PROD-2	Drilling	Drill	51. Drill 12-1/4" hole from 16,000' to 17,000'	60	2.5
4 PROD-2	Drilling	Circ	52. Circulate.	3	0.1
4 PROD-2	Drilling	Trip	53. Make a wiper trip to the 13-5/8" casing shoe and back to bottom.	10	0.4
4 PROD-2	Drilling	Circ	54. Circulate.	3	0.1
4 PROD-2	Drilling	Trip	55. Trip out of the hole.	17	0.7
4 PROD-2	Drilling	BHA	56. Stand back BHA.	4	0.2
4 PROD-2	Drilling	BHA	57. Lay down vertical drilling motor and equipment	4	0.2
4 PROD-2	**LOGGING OPERATIONS**			**95**	**4.0**
4 PROD-2	Logging	RigU/D	1. Rig up logging equipment.	1	0.0
4 PROD-2	Logging	Log	2. Run formation evaluation logs and caliper log, (3 runs).	48	2.0
4 PROD-2	Logging	RigU/D	3. Rig down logging equipment.	1	0.0
4 PROD-2	Logging	BHA	4. Make up 12-1/4" bit on wiper trip BHA and RIH.	4	0.2
4 PROD-2	Logging	Trip	5. Trip in hole to 17,000'.	17	0.7

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GEOTHERMAL CONSULTING AND DRILLING

TASK ANALYSIS

OPERATOR NAME: **SANDIA NATIONAL LABORATORIES**

FIELD NAME: Clear Lake, CA — Estimator / Engineer: Robert J. Swanson

Well Name: 20,000-ft EGS Well — Date: August 13, 2008

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days
				3,386	141.0
4 PROD-2	Logging	Circ	6. Circulate hole clean.	3	0.1
4 PROD-2	Logging	Trip	7. Trip out of hole.	17	0.7
4 PROD-2	Logging	BHA	8. Stand back BHA.	4	0.2
4 PROD-2	**CASING OPERATIONS**			**113**	**4.7**
4 PROD-2	Casing	RigU/D	1. Rig up casing running equipment.	3	0.1
4 PROD-2	Casing	RunCsng	2. Run 7200' of 9-5/8", 53.5 ppf, P-110, BTC casing.	24	1.0
4 PROD-2	Casing	RunCsng	3. Make up liner hanger assembly to 9-5/8" casing.	2	0.1
4 PROD-2	Casing	RigU/D	4. Rig down casing running equipment.	1	0.0
4 PROD-2	Casing	RunCsng	5. Run in hole with 9-5/8" liner on 5-1/2" drill pipe to 17,000'.	20	0.8
4 PROD-2	Casing	RunCsng	6. Set liner hanger.	1	0.0
4 PROD-2	Casing	RunCsng	7. Release from running tool.	1	0.0
4 PROD-2	Casing	RigU/D	8. Rig up cementing head on drill pipe.	1	0.0
4 PROD-2	Casing	Circ	9. Circulate and condition hole for cementing.	3	0.1
4 PROD-2	Casing	Cement	10. Mix, pump and displace cement per Table 4.	6	0.3
4 PROD-2	Casing	Trip	11. Pull running tool out of liner hanger and pick up 90'.	1	0.0
4 PROD-2	Casing	Circ	12. Circulate excess cement to surface.	4	0.2
4 PROD-2	Casing	Trip	13. Trip out of the hole.	10	0.4
4 PROD-2	Casing	RunCsng	14. Lay down liner running tools.	2	0.1
4 PROD-2	Casing	BHA	15. Pick up 12-1/4" clean out BHA.	4	0.2
4 PROD-2	Casing	Trip	16. Trip in the hole to the top of cement at 9700'.	10	0.4
4 PROD-2	Casing	Cement	17. Wait on cement for initial set to 500 psi compressive strength.	1	0.0
4 PROD-2	Casing	Cement	18. Clean out cement in the 13-5/8" casing to the top of the liner hanger.	2	0.1
4 PROD-2	Casing	Circ	19. Circulate hole clean.	2	0.1
4 PROD-2	Casing	BOP	20. Pressure test the liner lap to 1000 psi surface pressure.	1	0.0
4 PROD-2	Casing	Trip	21. Trip out of the hole.	10	0.4
4 PROD-2	Casing	BHA	22. Stand back BHA.	4	0.2
Phase V: Production Liner 3			**(8-1/2" Hole to 20,000' with 7" Casing)**	**805**	**33.5**
5 PROD-3	**DRILLING OPERATIONS**			**472**	**19.7**
5 PROD-3	Drilling	BHA	1. Make up 8-1/2" clean out BHA.	4	0.2
5 PROD-3	Drilling	Trip	2. Trip in the hole to the top of the 9-5/8" liner hanger.	10	0.4
5 PROD-3	Drilling	Drill	3. Drill out pack off bushing.	2	0.1
5 PROD-3	Drilling	Circ	4. Circulate the hole clean.	3	0.1
5 PROD-3	Drilling	Trip	5. Trip in the hole to the top of the landing collar at 16,880'.	7	0.3
5 PROD-3	Casing	BOP	6. Pressure test the liner to 1000 psi.	1	0.0
5 PROD-3	Drilling	Drill	7. Drill out the landing collar, 40' of cement, float collar, 80' of cement and float sh	4	0.2
5 PROD-3	Drilling	Drill	8. Drill 8-1/2" hole from 17,000' to 17,010.	1	0.0
5 PROD-3	Drilling	Circ	9. Circulate.	4	0.2
5 PROD-3	Drilling	Circ	10. Perform leak off test.	3	0.1
5 PROD-3	Drilling	Trip	11. Trip out of hole.	17	0.7
5 PROD-3	Drilling	BHA	12. Stand back BHA.	4	0.2
5 PROD-3	Drilling	BHA	13. Make up 8-1/2" bit on drilling BHA with vertical drilling system.	4	0.2
5 PROD-3	Drilling	Trip	14. Trip in hole to 17,010'.	17	0.7
5 PROD-3	Drilling	Drill	15. Drill 8-1/2" hole from 17,010' to 18,000.	83	3.5
5 PROD-3	Drilling	Circ	16. Circulate.	4	0.2
5 PROD-3	Drilling	Trip	17. Trip out of the hole for a new bit.	18	0.8
5 PROD-3	Drilling	BHA	18. Stand back BHA.	4	0.2
5 PROD-3	Drilling	BHA	19. Make up new 8-1/2" bit and run in the hole with BHA.	4	0.2
5 PROD-3	Drilling	Trip	20. Trip in hole to 18,000'	18	0.8
5 PROD-3	Drilling	Drill	21. Drill 8-1/2" hole from 18,000' to 19,000'	84	3.5
5 PROD-3	Drilling	Circ	22. Circulate.	4	0.2

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				3,386	141.0
5 PROD-3	Drilling	Trip	23. Trip out of the hole for a new bit.	19	0.8
5 PROD-3	Drilling	BHA	24. Stand back BHA.	4	0.2
5 PROD-3	Drilling	BHA	25. Make up new 8-1/2" bit and run in the hole with BHA.	4	0.2
5 PROD-3	Drilling	Trip	26. Trip in hole to 19,000'	19	0.8
5 PROD-3	Drilling	Drill	27. Drill 8-1/2" hole from 19,000' to 20,000'	84	3.5
5 PROD-3	Drilling	Circ	28. Circulate.	4	0.2
5 PROD-3	Drilling	Trip	29. Make a wiper trip to the 9-5/8" casing shoe and back to bottom.	6	0.3
5 PROD-3	Drilling	Circ	30. Circulate.	4	0.2
5 PROD-3	Drilling	Trip	31. Trip out of the hole.	20	0.8
5 PROD-3	Drilling	BHA	32. Stand back BHA.	4	0.2
5 PROD-3	Drilling	BHA	33. Lay down vertical drilling motor and equipment.	4	0.2
5 PROD-3	**LOGGING OPERATIONS**			**114**	**4.8**
5 PROD-3	Logging	RigU/D	1. Rig up logging equipment.	1	0.0
5 PROD-3	Logging	Log	2. Run formation evaluation logs and caliper log, (3 runs).	60	2.5
5 PROD-3	Logging	RigU/D	3. Rig down logging equipment.	1	0.0
5 PROD-3	Logging	BHA	4. Make up 8-1/2" bit on wiper trip BHA and RIH.	4	0.2
5 PROD-3	Logging	Trip	5. Trip in hole to 20,000'.	20	0.8
5 PROD-3	Logging	Circ	6. Circulate hole clean.	4	0.2
5 PROD-3	Logging	Trip	7. Trip out of hole.	20	0.8
5 PROD-3	Logging	BHA	8. Stand back BHA.	4	0.2
5 PROD-3	**CASING OPERATIONS**			**219**	**9.1**
5 PROD-3	Casing	RigU/D	1. Rig up casing running equipment.	3	0.1
5 PROD-3	Casing	RunCsng	2. Run 3200' of 7", 32 ppf, P-110, BTC casing.	10	0.4
5 PROD-3	Casing	RunCsng	3. Make up liner hanger assembly to 7" casing.	2	0.1
5 PROD-3	Casing	RigU/D	4. Rig down casing running equipment.	1	0.0
5 PROD-3	Casing	RunCsng	5. Run in hole with 7" liner on 5-1/2" drill pipe to 20,000'.	34	1.4
5 PROD-3	Casing	RunCsng	6. Set liner hanger.	1	0.0
5 PROD-3	Casing	RunCsng	7. Release from running tool.	1	0.0
5 PROD-3	Casing	RigU/D	8. Rig up cementing head on drill pipe.	1	0.0
5 PROD-3	Casing	Cement	9. Circulate and condition hole for cementing.	4	0.2
5 PROD-3	Casing	Cement	10. Mix, pump and displace cement per Table 5.	5	0.2
5 PROD-3	Casing	Trip	11. Pull running tool out of liner hanger and pick up 90'.	1	0.0
5 PROD-3	Casing	Circ	12. Circulate excess cement to surface.	5	0.2
5 PROD-3	Casing	Trip	13. Trip out of the hole.	17	0.7
5 PROD-3	Casing	RunCsng	14. Lay down liner running tools.	2	0.1
5 PROD-3	Casing	BHA	15. Pick up 8-1/2" clean out BHA.	4	0.2
5 PROD-3	Casing	Trip	16. Trip in the hole to the top of cement at 16,700'.	17	0.7
5 PROD-3	Casing	Cement	17. Wait on cement for initial set to 500 psi compressive strength.	1	0.0
5 PROD-3	Casing	Cement	18. Clean out cement in the 9-5/8" casing to the top of the7" liner hanger.	2	0.1
5 PROD-3	Casing	Circ	19. Circulate hole clean.	4	0.2
5 PROD-3	Casing	BOP	20. Pressure test the liner lap to 1000 psi surface pressure.	1	0.0
5 PROD-3	Casing	Trip	21. Trip out of the hole.	17	0.7
5 PROD-3	Casing	BHA	22. Stand back BHA.	4	0.2
5 PROD-3	Casing	BHA	23. Make up 6" clean out BHA.	4	0.2
5 PROD-3	Casing	BHA	24. Pick up 3500' of 3-1/2" drill pipe and cross over to 5" drill pipe.	10	0.4
5 PROD-3	Casing	Trip	25. Trip in the hole to the top of the 7" liner hanger.	17	0.7
5 PROD-3	Casing	Drill	26. Drill out pack off bushing.	3	0.1
5 PROD-3	Casing	Circ	27. Circulate the hole clean.	4	0.2
5 PROD-3	Casing	Trip	28. Trip in the hole to the top of the landing collar at 19,880'.	4	0.2
5 PROD-3	Casing	Circ	29. Circulate.	5	0.2
5 PROD-3	Casing	BOP	30. Pressure test the liner to 1000 psi.	1	0.0

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GEOTHERMAL CONSULTING AND DRILLING

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FIELD NAME: Clear Lake, CA

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Estimator / Engineer: Robert J. Swanson

Date: August 13, 2008

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days
				3,386	141.0
5 PROD-3	Casing	Trip	31. Trip out of hole.	20	0.8
5 PROD-3	Casing	BHA	32. Lay down 3-1/2" drill pipe.	8	0.3
5 PROD-3	Casing	BHA	33. Lay down 6" BHA.	6	0.3
Phase VI: Production Tie-Back (13-3/8" Casing)				**230**	**9.6**
6 PL1-TB	**CASING OPERATIONS**			**230**	**9.6**
6 PL1-TB	Casing	BHA	1. Pick up 13-5/8" retrievable bridge plug.	2	0.1
6 PL1-TB	Casing	Trip	2. Trip in hole on 5-1/2" drill pipe to 4850'.	10	0.4
6 PL1-TB	Casing	BOP	3. Set bridge plug inside the 13-5/8" production liner.	2	0.1
6 PL1-TB	Casing	Trip	4. Trip out of hole with plug setting tool.	5	0.2
6 PL1-TB	Casing	RigU/D	5. Rig up casing running equipment.	3	0.1
6 PL1-TB	Casing	RunCsng	6. Run 4800' of 13-3/8", 72 ppf, N-80, Vam Top casing.	15	0.6
6 PL1-TB	Casing	RunCsng	7. Stab in to tieback stem.	2	0.1
6 PL1-TB	Casing	RigU/D	8. Rig down casing running equipment.	1	0.0
6 PL1-TB	Casing	RigU/D	9. Rig up 13-3/8" cement head.	1	0.0
6 PL1-TB	Casing	Circ	10. Circulate and condition hole for cementing.	3	0.1
6 PL1-TB	Casing	Cement	11. Mix, pump and displace cement per Table 6.	8	0.3
6 PL1-TB	Casing	Cement	12. Wait on cement for initial set to 500 psi compressive strength.	12	0.5
6 PL1-TB	Casing	BOP	13. Lift BOP and rough cut 13-3/8" casing and lay down.	3	0.1
6 PL1-TB	Casing	BOP	14. Nipple down BOP.	3	0.1
6 PL1-TB	Casing	WH Ops	15. Cut of 20" casing head.	4	0.2
6 PL1-TB	Casing	WH Ops	16. Weld on 13-3/8", SOW x API 13-5/8", 3000 casing head.	18	0.8
6 PL1-TB	Casing	WH Ops	17. Install 12" x ANSI 900 Series master valve.	2	0.1
6 PL1-TB	Casing	BOP	18. Nipple up cross over spool and 20-3/4" BOP.	18	0.8
6 PL1-TB	Casing	BOP	19. Function test and pressure test BOP and 13-3/8" tieback casing to 2000 psi.	4	0.2
6 PL1-TB	Casing	BHA	20. Make up 12-1/4" clean out BHA.	4	0.2
6 PL1-TB	Casing	Trip	21. Trip in hole to the top of the float collar at 4720'.	5	0.2
6 PL1-TB	Casing	Drill	22. Drill out the float collar and clean out cement to the 13-5/8" tieback stem.	3	0.1
6 PL1-TB	Casing	Circ	23. Circulate.	1	0.0
6 PL1-TB	Casing	Trip	24. Trip in hole to the top of the retrievable bridge plug at 4850'.	1	0.0
6 PL1-TB	Casing	Circ	25. Circulate hole clean.	2	0.1
6 PL1-TB	Casing	Trip	26. Trip out of the hole.	5	0.2
6 PL1-TB	Casing	BHA	27. Lay down 12-1/4" BHA.	8	0.3
6 PL1-TB	Casing	BHA	28. Pick up bridge plug retrieval tool and make up to 5-1/2" drill pipe.	3	0.1
6 PL1-TB	Casing	Trip	29. Trip in hole to the top of the retrieval bridge plug at 4850'.	8	0.3
6 PL1-TB	Casing	BOP	30. Release bridge plug.	1	0.0
6 PL1-TB	Casing	Trip	31. Trip out of hole with retrievable bridge plug.	8	0.3
6 PL1-TB	Casing	BHA	32. Lay down bridge plug and retrieval tool.	1	0.0
6 PL1-TB	Casing	BHA	33. Lay down all drill collars.	16	0.7
6 PL1-TB	Casing	BHA	34. Lay down all drill pipe.	48	2.0

Appendix C - Discussion of Select Technologies of Interest

This section will provide more detailed discussion of selected technologies of interest. It is intended to supplement the preceding R&D recommendations by discussing relevant aspects of critical technologies.

C.1 Measurement and logging tools

It is first noted that the inventory of tools within the oil and gas industry for the evaluation of both well and formation characteristics is extensive. A comprehensive review of all available oil and gas tools and their applicability to geothermal is beyond the scope of this report. A thorough evaluation of the applicability of these tools to EGS would require analysis by a multi-disciplinary team of experts, as discussed in section 6.2. It is recommended that a more comprehensive evaluation of the applicability of oil and gas tools to the geothermal industry be performed in the near future as a distinct effort.

It is also noted that a large class of wireline logging technologies is omitted in this report. Many of these tools can be used in combination with thermal insulation methods (e.g. Dewaring) to permit tool operation at high temperature for short periods of time. Some logging tools capable of operation up to temperatures of 300 ºC have been developed in the past for select applications. The technology evaluation in this section will be confined to the more limited well construction logging and measurement activities associated with drilling. The discussion is meant primarily to provide a glimpse of the extent of geophysical measurement technology, most of which is largely unused in geothermal applications.

The use of measurement and logging while drilling has matured a great deal in the last 10 years. These tools have been developed by the oil and gas industry for use in primarily sedimentary depositional environments and are investigated in light of the goals set for EGS systems. A definition of the terms is first provided, recognizing that the line between these two areas blurs over time.

1) Measurement While Drilling (MWD): Tools that measure downhole parameters of the bit interaction with the rock are MWD tools. These measurements typically include vibration and shock, mudflow rate, direction and angle of the bit, weight on bit, torque on bit, and downhole pressure.

2) Logging While Drilling (LWD): Tools that measure downhole formation parameters are LWD tools. These include gamma ray, porosity, resistivity and many other formation properties. The measurements fall into several categories that are discussed below. The oldest and perhaps most fundamental formation measurements are spontaneous potential (SP) and gamma ray (GR). Today one or both of these traces are used mostly for correlation between logs. Electric or formation resistivity logs are another class of logs used in oil and gas logging. Because of the long history of these logs, several varieties

have evolved. The electrical basis of this class of logs is to measure the conductivity or resistivity of the various geologic materials and fluids in them. The resistivity of shales vs. that of a clean sand sets the limits for an ideal electric log. The fluids in the formation are also reflected in this measurement as water is conductive when found in boreholes and oil is not. The basic use of electric logs is to delineate bed boundaries and in combination with other logs to determine gas/oil/water contacts. Yet another class of logs is density logs. These logs are indicative of the formation density of the material in the well bore. These logs require either a neutron or a gamma source, and actually measure gamma ray flux differences. Porosity tools are another class of common logging tools. These tools normally use chemically or now more common electrically generated neutron to estimate formation porosity. Since these logs are normally calibrated in sandstone, limestone or dolomite care has to be taken when measurements are made in different rock types. Finally in the last few years a number of specialty tools have evolved, these include specialized formation pressure testing tools which can be run while drilling, nuclear magnetic resonance tools, and pulsed neutron spectroscopy tools to list only the most popular.

Rationale for use

In recent years the cost of an average oil and gas hole has increased dramatically. Part of this cost increase has been driven by the need to go after deeper and more complicated reserves with greater hole failure risks. As a reaction to increased risk, the use of LWD and MWD technology and techniques has increased. In the final analysis, the decision to use LWD and MWD tools depends on managing risk. The EGS program moves the art of geothermal drilling into a new region of risk. The evaluation of the LWD and MWD technologies must be undertaken to determine the applicability of these technologies to the particular risks faced in this new effort. It is important to realize that in many prospective EGS applications, igneous or metamorphic rock may not be encountered until the production interval is reached. These deeper holes may look more like the classic oil and gas wells over significant lengths. The possible uses of LWD and MWD technologies are subsequently examined with this in mind. This process will mainly consist of a listing of common tools and their uses.

Measurements available from current LWD/MWD oil field tools

Mention of companies and tool or service names does not imply endorsement by Sandia National Laboratories; it appears that most companies involved in MWD and LWD have a version of these tools. This information was primarily gathered through internet searches.

Measurement Name: Downhole Weight On Bit	
Class: MWD	**Measurement Function: -**
Max Temp: 175ºC	**Length:** 25’
Advertised Oil Field Use : This trace allows the determination of the	**Potential Geothermal Use:** Previous DOE programs have shown that

actual weight on bit at the bit.	this measurement can be used to detect bit-damaging events and prolong bit life.
Special Conditions : None	**Example Tool:** Schlumberger TeleScope Baker Hughes Inteq CoPilot (service)

Measurement Name: Downhole Torque On Bit	
Class: MWD	**Measurement Function: -**
Max Temp: 175ºC	**Length:** 25'
Advertised Oil Field Use : This trace allows the determination of the actual torque on bit.	**Potential Geothermal Use:** Previous DOE programs have shown that this measurement can be used to detect bit-damaging events and prolong bit life.
Special Conditions : None	**Example Tool:** Baker Hughes Inteq CoPilot (service), Schlumberger TeleScope

Measurement Name: Downhole flow rate	
Class: MWD	**Measurement Function: -**
Max Temp: 175ºC	**Length:** 25'
Advertised Oil Field Use : This measurement allows the determination of the mudflow rate at or near the bit.	**Potential Geothermal Use:** Previous DOE programs have shown this measurement in combination with surface measured return flow is critical to detecting lost circulation events. This measurement has also been useful for detecting pipe washout and bit plugging conditions in the past.
Special Conditions : None	**Example Tool:** Schlumberger TeleScope

Measurement Name: 3-D Shock	
Class: MWD	**Measurement Function: -**
Max Temp: 175ºC	**Length:** 25'
Advertised Oil Field Use : This trace used in combination with 3-D vibration is used to monitor bit conditions. Avoiding shock loads has been shown to increase bit life	**Potential Geothermal Use:** Same as oil field but more critical in harder formations.
Special Conditions : None	**Example Tool:** Baker Hughes Inteq VSS (service), Schlumberger TeleScope

Measurement Name: 3-D Vibration	
Class: MWD	**Measurement Function: -**
Max Temp: 175ºC	**Length:** 25’
Advertised Oil Field Use : This trace used in combination with 3-D shock is used to monitor bit conditions. Avoiding damaging vibrations has been shown to increase bit life, and increase ROP. Also used to determine RPM at bit	**Potential Geothermal Use:** Same as oil field but more critical in harder formations. RPM determination critical to avoiding several bit damaging situations.
Special Conditions : None	**Example Tool:** Schlumberger TeleScope Baker Hughes Inteq CoPilot (service)

Measurement Name: Direction and Inclination	
Class: MWD	**Measurement Function:**
Max Temp: 175ºC	**Length:** 25’
Advertised Oil Field Use : These traces are used in directional drilling. Both are required to control bit position	**Potential Geothermal Use:** Same as oil field.
Special Conditions : None	**Example Tool:** Schlumberger TeleScope

Measurement Name: Azimuthal Natural Gamma Ray	
Class: LWD	**Measurement Function:** Gamma Ray
Max Temp: 150ºC	**Length:** 26’
Advertised Oil Field Use : This trace measures the naturally occurring gamma radiation in several directions from the borehole. The trace is used to identify shales and clays as opposed to sands in lithologic sequences. Processed trace is a primary correlation trace between logs run at differing times.	**Potential Geothermal Use:** Needs to be determined.
Special Conditions : None	**Example Tool:** Schlumberger EcoScope

Measurement Name: Multi-frequency resistivity	
Class: LWD	**Measurement Function:** Electric
Max Temp: 150ºC	**Length:** 26’
Advertised Oil Field Use :	**Potential Geothermal Use:**

This measurement in oil and gas logging provide bed boundary and gas/oil/water contact information.	Could be used in sedimentary sequence for bed boundary identification. Usefulness in metamorphic and igneous formation needs to be determined.
Special Conditions : None	**Example Tool:** Schlumberger EcoScope

Measurement Name: Sonic	
Class: LWD	**Measurement Function:** Sonic
Max Temp: 150ºC	**Length:** 23’
Advertised Oil Field Use : This measurement set provides information on porosity, mechanical rock properties and borehole stability.	**Potential Geothermal Use:** Same as oil field.
Special Conditions : None	**Example Tool:** Baker Hughes Inteq SoundTrak , Schlumberger sonicVision

Measurement Name: Multi-frequency, multi-depth resistivity	
Class: LWD	**Measurement Function:** Special/Electrical
Max Temp: 150ºC	**Length:** 11’
Advertised Oil Field Use : This tool is used for formation imaging. Used for fracture identification and finding stress orientation. Also provides temperature data.	**Potential Geothermal Use:** This tool may find use in advanced directional drilling applications. If fracture imaging can be done in non-sedimentary geologies may be useful for fracture mapping and stress orientation
Special Conditions: Requires use of conductive mud system.	**Example Tool:** Baker Hughes Inteq StarTrak; AziTrak , Schlumberger GeoVision

Measurement Name: Annular pressure	
Class: LWD	**Measurement Function:** Pressure
Max Temp: 150ºC	**Length:** 26’
Advertised Oil Field Use : This trace measures the pressure near the BHA-open hole interface.	**Potential Geothermal Use:** This trace would be used to determine areas where lost circulation may be occurring.
Special Conditions : None	**Example Tool:** Baker Hughes Inteq PressTEQ (service), Schlumberger

	EcoScope

Measurement Name: Azimuthal Density	
Class: LWD	**Measurement Function:** Density
Max Temp: 150ºC	**Length:** 26’
Advertised Oil Field Use : This trace measures the formation density in multiple directions out from the bore hole. Used in combination with other measurements for formation lithology identification	**Potential Geothermal Use:** Needs to be determined.
Special Conditions : None	**Example Tool:** Baker Hughes Inteq LithoTrak , Schlumberger EcoScope

Measurement Name: Compensated Neutron	
Class: LWD	**Measurement Function:** Porosity
Max Temp: 150ºC	**Length:** 26’
Advertised Oil Field Use : This measurement is used to estimate porosity. This trace is integrated in most logging tools as a part of a triple combo.	**Potential Geothermal Use:** Same as oil field.
Special Conditions : None	**Example Tool:** Baker Hughes Inteq APLS , Schlumberger EcoScope

Measurement Name: Photoelectric Factor	
Class: LWD	**Measurement Function:** Special
Max Temp: 150ºC	**Length:** 26’
Advertised Oil Field Use : This trace measures the average atomic number of the formation constituents, used with density to determine mineralogy.	**Potential Geothermal Use:** Needs to be determined. Mineralogy information may be useful for EGS chemical interaction understanding.
Special Conditions : None	**Example Tool:** Schlumberger EcoScope

Measurement Name: Ultrasonic Caliper	
Class: LWD	**Measurement Function:** Borehole
Max Temp: 150ºC	**Length:** 26’

Advertised Oil Field Use : Measures the hole size directly behind the bit. Used to determine size of hole and rugosity	**Potential Geothermal Use:** Same as oil field use. Important for casing and cementing considerations.
Special Conditions : None	**Example Tool:** Baker Hughes Inteq LithoTrak , Schlumberger EcoScope

Measurement Name: Porosity	
Class: LWD	**Measurement Function:** Porosity
Max Temp: 150ºC	**Length:** 26’
Advertised Oil Field Use : This trace measures the apparent porosity of the formation based on fast neutrons emitted by a neutron source. Neutron source may be chemical or electrical in nature.	**Potential Geothermal Use:** Same as oil field.
Special Conditions : None	**Example Tool:** Baker Hughes Inteq LithoTrak , Schlumberger EcoScope

Measurement Name: Sigma	
Class: LWD	**Measurement Function:** Special
Max Temp: 150ºC	**Length:** 26’
Advertised Oil Field Use : This trace is a measure of the macroscopic absorption cross section for thermal neutrons, used to determine formation water saturation.	**Potential Geothermal Use:** Needs to be determined.
Special Conditions : None	**Example Tool:** Schlumberger EcoScope

Measurement Name: Pulsed neutron spectroscopy	
Class: LWD	**Measurement Function:** Special
Max Temp: 150ºC	**Length:** 26’
Advertised Oil Field Use : This measurement utilizes a pulsed neutron source, and gamma ray detectors to estimate formation oil content, salinity, lithology, porosity and clay content.	**Potential Geothermal Use:** Needs to be determined.

Special Conditions : None	**Example Tool:** Schlumberger EcoScope

Measurement Name: Nuclear magnetic resonance	
Class: LWD	**Measurement Function:** Special
Max Temp: 150ºC	**Length:** 39'
Advertised Oil Field Use : This measurement is used to determine free and bound fluid volumes, fluid type, porosity and permeability estimation.	**Potential Geothermal Use:** Needs to be determined.
Special Conditions : Informal conversations with persons who have used this tool indicate that its use is best understood in sandstone.	**Example Tool:** Baker Hughes Inteq MagTrak , Sperry MRIL-WD

Measurement Name: Seismic	
Class: LWD	**Measurement Function:** Special
Max Temp: 150 ºC	**Length:** 14'
Advertised Oil Field Use : Data derived from this tool is used to look-ahead for formation changes, pore pressure changes and faults.	**Potential Geothermal Use:** Same as oil field.
Special Conditions : Requires active seismic source on surface	**Example Tool:** Schlumberger seismic Vision

Measurement Name: Formation Pressure	
Class: LWD	**Measurement Function:** Pressure
Max Temp: 150ºC	**Length:** 31.5'
Advertised Oil Field Use : This tool measures the formation pressure and fluid mobility while drilling. This measurement can replace some drill-stem (DST) formation test measurements. Device seals against borehole wall and isolates formation from drilling fluids for testing. This measurement is also used for drilling optimization.	**Potential Geothermal Use:** Same as oil field.
Special Conditions : None	**Example Tool:** Baker Hughes Inteq TesTrak , Schlumberger Stethoscope

Commentary

As one can see from the list, most tools are rated to 150ºC. Some measurements can be made up to 175ºC. These tools provide limited bandwidth data to the surface via mud pulse telemetry and higher bandwidth data via large onboard memories which can be unloaded as a part of a bit trip.

The case for MWD tools in EGS is relatively clear. MWD may not be required for the full duration of the drilling effort but will likely be a requirement in deeper and/or directionally drilled holes to assure that the hole is completed in the target area. The costs associated with damaged bits and BHA components while drilling hard lithologies also clearly implies the need for MWD. The Sandia Diagnostics While Drilling (DWD) program previously demonstrated the value of a 225ºC MWD tool in geothermal drilling applications. Real-time information provided by the tool during field trials was used to more optimally control drilling parameters resulting in improved ROP and extended bit life. More in depth reviews of this work have been published and presented by others, and may be of interest to some readers[8]. It is worth mentioning that due to sensor unavailability, one class of measurement not present in the DWD tool that is present in most current MWD tools is direction and inclination. These measurements are critical in directional drilling.

The case for most LWD tools or traces will have to be made on a well-by-well basis. As has been noted, most LWD traces and tools are optimized for drilling sedimentary formations. Additional field experience will likely be required to define the useful LWD suite for EGS drilling programs.

The basic limitation of the available tools is temperature and accommodations will need to be made in the mud system and operational procedures to maintain the tools within their operational temperature ranges long enough to allow a reasonable evaluation. After some experience is gained with the available tools, efforts to construct versions suitable for higher temperatures could begin.

C.2 Rock reduction technologies

This section will discuss relevant aspects of conventional drilling technologies not currently used in the geothermal industry. It will focus on those drilling technologies that have been shown to deliver significantly greater performance in related applications than conventional roller cone technology. Each section will also discuss barriers and the potential for introduction into the geothermal market.

[8] J.L.Wise, A.J. Mansure and D.A. Blankenship, “Hard-Rock Field Performance of Drag Bits and a Downhole Diagnostics-While-Drilling (DWD) Tool”, *Proceedings World Geothermal Congress 2005*, Antalya, Turkey, 24-29 April 2005

C.2.1 PDC bits

The use of PDC (polycrystalline diamond compact) cutter bits has increased dramatically in recent years in the oil and gas industry. Benefits of this technology include significantly higher ROP and cumulative footage as compared to roller cone technology in most applications. PDC bits currently account for 65-70% of all footage drilled today compared to 26% in 2000. This market inversion of PDC and roller cone bits within the last ten years reflects the rapid advancement and proven benefits of PDC technology. The use of this aggressive technology in geothermal applications by contrast is very limited. An examination of the factors affecting PDC bit performance is useful in understanding their slow introduction into geothermal applications.

The three primary issues leading to poor performance of PDC bits and the reluctance to use them in the geothermal industry are cutter wear, vibration associated cutter failure and limited large bit diameter availability. In simple terms, the first two of these issues can be related to three fundamental lithological characteristics:

- Rock abrasiveness – This rock property, in combination with cutter temperature, largely dictates cutter wear. Increased cutter wear results in a corresponding decrease in both ROP and bit life.
- Rock hardness – This rock property is typically associated with the unconfined compressive strength (UCS) of the rock and has a significant influence on drill string vibration. Harder formations tend to promote drill string vibration, which in turn can lead to high impact loading of the bit and cutter damage.
- Formation heterogeneity or interbeddedness – Formation heterogeneity refers to alternating layers of different types of rock within a formation. Heterogeneity is particularly problematic when alternating layers of hard and soft rock in close proximity to each other are frequently encountered. The transitions from hard to soft layers result in load changes to the bit that excite the drill string causing potentially damaging vibrations.

The use of PDC bits has historically been limited to soft and medium hardness formations due to an inability to cope with the wear or vibration related problems associated with the more demanding of the lithological characteristics defined above. Rock hardness and abrasiveness are the dominant mechanical properties of geothermal applications that have limited the use of these types of bits. However, there has been significant improvement in cutter technology and understanding of operating conditions within the last five years leading to a significant increase of the operating envelope of PDC bits.

Use of these bits in the hard, interbedded, non-abrasive carbonate formations in the Middle East is now routine according to bit manufacturers. The drilling of hard, abrasive, interbedded formations continues to be challenging for PDC bits although capabilities are rapidly improving. Successful use of this technology in current form, in both scenarios, is predicated on optimizing operating parameters to mitigate or avoid damaging conditions at the bit.

The use of appropriate drilling fluid, weight on bit and rotational speed, for example, are critical to improving performance and reliability in abrasive formations. Optimal selection of these drilling parameters acts to reduce cutter temperatures and mitigate bit wear and associated performance degradation. Similar benefits are seen when drilling parameters are carefully regulated in interbedded environments with high vibration potential. Many bit companies currently offer comprehensive design and simulation services for the selection of bit design and operating parameters best suited to economically and reliably drill difficult formations. It is the combination of technology advancement and improved operational understanding that has allowed PDC bits to rapidly expand their scope of application to more challenging lithologies.

This extension of PDC capabilities has largely been driven by activity in the oil and gas industry that has focused on exploiting hard and hot reservoirs not previously considered to be economical to produce. In some respects this represents a convergence of geothermal and oil and gas drilling challenges. It is reasonable to conclude, given the bit manufacturer's demonstrated history of successfully meeting oil and gas industry drilling challenges and the current state of development of the technology, that the potential for successfully introducing PDC bits and their associated benefits into the geothermal industry is high in the near term.

Finally, the use of PDC bits in the geothermal industry has also been limited by a lack of availability of larger bit sizes. Up until a few years ago, PDC bits greater than 12 ¼" diameter were difficult to obtain. Geothermal wells tend to be of larger diameter than oil and gas wells. Thus many upper hole intervals could not be drilled using PDCs in the past because the needed bit sizes were not available (for example, the first 10,000 ft of the well specification in this report requires a bit larger than 12 ¼"). Bit manufacturers are currently making bits up to 24" in diameter. Discussions with them indicate that the development of large PDC bits has been hampered by stability issues. As with other PDC performance problems, these technical obstacles are being progressively addressed.

C.2.2 Percussion Hammers

The pneumatic down the hole percussion hammer is arguably the best performing commercial hard rock drilling technology available today and is used extensively in the mining, construction and water well drilling industries. Air or foam is conventionally used to both power the hammer and clean the borehole with bit diameters commercially available up to 48". A typical valveless down the hole pneumatic hammer consists of a ported air feed conduit, more commonly known as a feed tube, check valve assembly above the feed tube to prevent ingress of wellbore fluids into the drill, a reciprocating piston that produces impact energy, and drill bit with tungsten carbide button inserts and associated retaining hardware. This technology is habitually employed in medium to extremely hard rock formations. Demonstrated penetration rates in granitic and metamorphic rock using this technology are typically several times greater than those achieved with roller cone technology. The lower comparative weight on bit required for percussion hammers also reduces hole deviation problems.

Hammers have been successfully used in the oil and gas industry to drill entire boreholes of lengths up to 5.4 km[9]. The use of boosters is required in such applications to generate sufficient pressures for overcoming bottom hole pressures and removing cuttings at great depths. Commercial hammer configurations are also available for reverse circulation and casing drilling applications.

Temperature limit for many of the non-metallic components is the primary factor affecting the use of off-the-shelf down the hole percussion hammer technology in geothermal applications. Elastomeric seals and plastic parts used in conventional products are the main components at risk. It has been demonstrated in the past that appropriate material substitutions can be made to permit operation of these drills at temperatures of 232 ºC[10]. Extension of this technology to high temperature geothermal applications therefore appears to be feasible. Other potential drilling issues related to the use of this technology in geothermal applications include defining appropriate well control procedures when air drilling and assessing the impact of high formation temperatures on bit button wear.

The development of hydraulic hammers using either water or drilling mud has also been pursued in recent years to improve drilling performance in medium to hard rock applications[11]. Hydraulic hammers have the potential to operate at higher pressures than pneumatic hammers with the ultimate objective of operation in deeper, high pressure basins. These technologies have seen limited commercial use to date and are currently hampered by a variety of reliability issues. They require valving to regulate fluid flow between chambers which is susceptible to contamination and wear associated damage. The use of an incompressible fluid to power the piston can also result in the presence of dynamic pressure transients that can damage hydraulic hammer components. Thus although this technology has the potential to increase drilling capabilities, there is still significant development required before it can be used on a commercial basis.

C.2.3 Under-Reamers

Under-reamer technology has proven to be very beneficial to oil and gas well construction efforts. This survey and assessment was conducted to identify the limitations of existing technology for EGS applications. As stated in Section 6.6.1 of the MIT Report,

> *Monobore designs that use expandable tubulars require under-reamers. The use of under-reamers is common in oil and gas drilling through sediments, and provides cementing clearance for casing strings that would not otherwise be available. However, high quality under-reamers for hard rock environments are not common, with expansion arms often being subject to failure. Currently, underreaming in oil and gas operations utilizes bicenter bits and PDC type cutters. Unfortunately,*

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[9] Numa, Project Summaries, Oil & Gas Industry, Natural Gas Exploration to Great Depths, http://numahammers.com/jobsframe.html

[10] Finger, J.T. "Investigation of Percussion Drills for Geothermal Applications" *Journal of Petroleum Technology*, pp. 2128-2136, December, 1984.

[11] Optimization of Mud hammer Drilling Performance, NETL Exploration and Production Technologies project, DE-FC26-00NT40918

the success of PDC cutters in geothermal environments has not yet been established. More robust under-reamers are required for EGS applications.

Generally, the term under-ream means to enlarge a wellbore past its original drilled size. Under-reaming is required for geothermal wellbore construction for both performance and cost issues. Considering performance, a large diameter wellbore is required for large flow rates of the wellbore production fluids. Regarding cost, reducing the number of casing strings required reduces the overall cost of the wellbore construction. Under-reaming may be done for safety reasons as well. Although this may not be applicable to geothermal well construction, some well designers perceive that drilling a small diameter pilot hole is safer, and if no high pressure gas is encountered, then the pilot hole can be enlarged using a reaming operation. Reaming may also be required if the hole was not drilled as large as was originally intended. This problem may not be discovered until the bit is tripped out of the hole and the bit wear is physically observed. Finally, reaming may also be required when the formations are plastic and flow back into the wellbore over time. This may not be likely with the formations encountered in geothermal reservoirs.

Reaming has become more of a standard practice in the oil and gas industry for the reasons cited in the above introduction. It continues to be an expanding market. It was estimated to comprise approximately 16 percent of the total worldwide footage drilled in 2007[12].

The survey below was conducted to determine the current state of the art in under-reaming and hole opening technology that can be applied to geothermal wellbore construction. It was conducted by a web-based literature survey, drilling case study reviews and discussions with subject matter experts within the industry. The available hole-opening technologies were categorized, currently available hardware identified and their applicability to geothermal wellbore construction assessed.

C2.3.1 Survey

Fundamentally, hole openers incorporate the same cutting structure technology used in the drill bits used to produce pilot holes. Under-reamers are sometimes classified by their hole opening function when the tool enters the hole, i.e., Ream-on-Demand, or Multi-Diameter Tools. Ream on Demand, or active reaming, is typically deployed by modification of a rig operating parameter, typically adjusting the hydraulic condition of the drilling fluid delivered to the bit. This action results in the expansion of a tool downhole to perform the under-reaming function. Alternatively, multi-diameter tools refer to a passive tool that has multiple cutting structures. These tools consist of a pilot section and an eccentric reaming section. The pilot section can be offset from wellbore centerline to allow the eccentric section to be deployed through existing casing. Although, Ream-on-Demand and Multi-Diameter Tool are useful terms for describing the

12 http://www.halliburton.com/public/news/source_files/Newsletters/KCNews/2005/Dec05SDBS_NewReamer.html

mode of deployment, the results from this survey are categorized by the cutting structures used for rock reduction, and include roller cone, fixed cutters, and hammer bits. These types of under-reamers are summarized below. Currently available equipment in the industry is also described, followed by an assessment of their suitability for geothermal wellbore construction.

<u>Roller Cone Type Under-Reamers (Expandable Arm)</u>

Summary
Roller cone based under-reamers are the conventional approach in geothermal drilling. They consist of a tool equipped with cutter arms that are expanded outward by adjusting hydraulic parameters after the assembly has passed below the casing. Some manufacturers offer both two and three-cone versions.

Availability
Roller-cone type under-reamers are available from Smith International (Figure C-1), Baker Hughes, Weatherford, Mills Machine, and Stuckeys.

Assessment
The two-cone versions are deemed to be stronger than three-cone under-reamers since they allow larger bearings to be accommodated. Some three-arm models can expand to nearly twice the original tool diameter.

When deploying the arms, the driller must be careful to ensure the arms are fully extended before applying thrust to the cones. Otherwise, the cones are not engaging the rock in the preferred design condition and may be subject to accelerated wear or failure.

The MIT report indicates that these tools may encounter problems when retracting the arms to withdraw the tool back into the casing, yet this was not identified as an industry-wide problem in this survey. Adequate circulation through the tool, thereby cleaning out the arm-pits in the tool housing, should allow the arms to be retracted successfully.

Like their full-hole counterparts, roller cone under-reamers are subject to the moving part limitations that currently limit the life of roller cone bits. The bearings must also be sealed for geothermal drilling conditions. Nevertheless, they are perceived as effective tools for under-reaming in conventional geothermal drilling

C-1 Rock Type Under-reamer (Smith).

Bi-Center Bit Under-Reamers

Summary

Bi-center bits are used to drill and ream at the same time. They can pass through smaller diameter casing, by offsetting the pilot section from centerline, and then drill out a larger diameter hole. They are available with both PDC and natural diamond cutting structures.

Availability

Many of the large bit companies provide bi-center bits using PDC based cutting structures, including Varel (Figure C-2)and Reed Hycalog. DODWCO offers a natural diamond cutting structure (Figure C-3).

Assessment

Fixed cutter bits are being used in harder formations in oil and gas drilling but have not seen widespread application in geothermal drilling. The upper sections in geothermal drilling may be candidates for use of PDC bit technology. Traditional PDC bits have been used in some cases for geothermal wellbore construction; increased use should de-risk the application of bi-center bits for the geothermal market. In contrast to roller-cone based cutting structures, these bits are attractive for the high temperature compatibility of their native materials (diamond, tungsten carbide), lack of moving parts and unnecessary fluid seals.

Since these cutting structures employ synthetic diamond cutting elements, they can be subject to failure under severe drillstring vibrations. This becomes especially pronounced in harder rock. They should be used with discretion when the likelihood of drill string vibrations becomes more pronounced.

C-2 Bi-Center Bit (Varel).

C-3 Bi-Center Bit with Natural Diamond Cutting Structure (DOWDCO).

Bi-Center Reaming Sections

Summary
Bi-Center reaming sections are eccentric add-ons in the bottom hole assembly that produce the same cutting action as employed on bi-center bits. They are similar to bi-center bits yet comprise only the eccentric wing section. They can be combined with other types of cutting structures in the pilot section.

Availability
They are available form Hughes Christensen (Figure C-4**Error! No bookmark name given.**). They can be used in pendulum or packed hole assemblies.

Assessment
Like PDC based cutting structures, the reaming sections may be applicable for the upper sections of the well.

Since these sections comprise part of the cutting structure, they may be prone to more drillstring vibration. The magnitude of the cutting loads can vary between the pilot section and the reaming section resulting in deleterious drillstring vibrations that can be damaging to the cutting structures.

C-4 Reaming tool with a Roller Cone Pilot Bit (Hughes Christensen).

Active Drag-Type Under-Reamers

Summary

These tools employ fixed-cutter (i.e., PDC) cutting structures that are actively deployed outward from the main body of the tool. They can be moved radially outward through a piston type of assembly, or rotated out on a hinged section. They employ drag type cutting structures.

Availability

Security DBS/ Halliburton and Andergage offer cutting structures that are actively deployed radially outward to increase the wellbore diameter on demand. The Security DBS model features a cutting structure that is deployed radially outward (Figure C-5). The cutting mechanism is designed to be stable so that the deployment system is not necessary to maintain the stiffness of the cutting structure during operation.

A comparable tool is provided by Tri-Max, except the reaming sections are deployed by regulation of the weight on bit. Once the under-reamer has cleared the casing shoe, increased thrust will deploy the reaming section to its full diameter. The reamers are correspondingly retracted when weight on bit is removed to pull the tool back into the casing.

Security DBS also provides a drag type cutting structure (Figure C-6), with cutter arms that are deployed by a hydraulic pressure. This rotary type of system allows the wellbore diameter to be significantly increased. A rack and pinion system is used to deploy the arms out; these are held at specific angles by stop blocks within the housing. These systems are also offered by Harvest Tool.

Assessment
These cutting structures rely upon active deployment systems to deploy the under-reaming function. The radially deployed systems appear to be more robust for the rigors of hard-rock drilling than the rotated arms that are subject to bending type failures. Their utility in hard-rock applications needs to be independently assessed.

C-5 Halliburton under-reamer

C-6 Halliburton under-reamer

<u>Down The Hole (DTH) Hammer Type Cutting Structures</u>

Summary
Down-hole hammers use the percussive action of a hammer to drive a bit equipped with hardened penetrators into the rock. These cutting structures are indexed rotationally between successive blows to reduce the entire frontal area of the bit. Some of these cutting structures employ movable inserts on the face of the bit that allow part of the

cutting structure to pivot or deploy out beyond the gage diameter of the bit to introduce an under-reamer type of function.

Availability
NUMA (Figure C-7) provides a hammer bit with wings that move radially outward once the bit clears the casing shoe and thrust is applied to the bit face. These wings are mounted on an inclined plane and naturally retract to clear the casing when the thrust is removed.

Eastern Drillers Manufacturing provides a bit (not pictured) where a wing of the cutting structure is mounted on a pivot. Under normal rotation the wing is deployed to the full gage position below the casing. Reverse rotation allows the wings to be retracted for subsequent withdrawal into the casing. Non-US manufacturers (e.g., Mitsubishi) are known to provide comparable cutting structures.

Assessment
DTH hammer systems are able to effectively reduce hard rock at high penetration rates. The overall system approach must be validated as an effective system for geothermal drilling, especially at increased depths.

C-7 Hammer bit under-reamer (NUMA).

C2.3.2 Technology Assessment

Geothermal drilling is challenging with hot, hard, abrasive, and corrosive conditions severely limiting bit life and performance. Like their pilot-hole drilling counterparts, under-reamers must be chosen for their drillability of each specific targeted geothermal formation and the overall drilling conditions.

Roller cone bits are currently used to drill the majority of geothermal wells. Although they drill at slow rates, these bits are efficient and durable. Still, bit life can be limited due to wear of the inserts, cone failure, bearing seizure, and seal failures at high temperatures and in severe environments. Nevertheless, the manufacturers and service companies surveyed didn't perceive roller cone based under-reamers to be prone to tool failure during drilling or stuck arms during retraction.

Drag bit cutting structures offer the possibility of increased performance to the geothermal market, owing to their success in oil and gas drilling in hard formations. PDC bits offer benefits over roller cone technology because of their aggressive cutting structures, high temperature resistance, lack of moving parts, and lack of seals. Increased use of PDC bits for cutting pilot holes must be realized before these cutting structures can be adopted for under-reaming applications. PDC bits are finding increased application on upper hole sections of conventional geothermal wells. Notably, Cal-Energy has used PDC bits for surface to 5000 ft formation depths. Additionally, CFE has used PDC bits to drill the upper 4500 feet in Mexico (Reference: Jose Iguarez, Baker Hughes). This increased PDC bit use will help pave the way for expanded use of these cutting structures for under-reaming applications in the form of bi-center bits and eccentric reaming sections. These bit applications must be used under stable drilling conditions to reduce the possibility of damage to the hard, but brittle cutting structures they employ. It is unlikely that the more sophisticated Ream-On-Demand under-reamers will find application until drag cutting elements have been de-risked and adopted by the geothermal drilling industry.

Down hole hammer bits potentially offer high penetration rate performance to geothermal wellbore construction. Historically, they have been successful in shallow water well and mining drilling. Removal of the cuttings may become cost prohibitive at greater depths. The viability of this technology should be addressed from a systems perspective for applicability to deep drilling to discern the viability of these cutting structures as under-reamers.

Summary
This survey has identified the current state of the art in under-reaming technology for geothermal wellbore construction. The available technologies have been categorized by the type of rock reduction employed and include, roller cone, drag-cutters, and hammer bits. This assessment comprises an overview of the industry; it should be succeeded by thorough observations of actual hardware and system performance. Field validations should be conducted to evaluate this current technology and identify specific improvements necessary to support geothermal wellbore construction.

C.3 Zonal isolation tools – Packers

Typical Packer Uses
Packers are tools that employ an elastomeric material to seal against the casing or open hole wall in order to control flow. They are used in steam injection operations, wellbore testing, cement squeezing, fracturing, acidizing, to protect the casing from high formation pressure and formation fluids, to hold annular fluids, and to isolate between zones. They are sometimes used as anchors for deflectors when a window is to be milled thru the casing so that a lateral leg can be drilled. Other applications include using packers at the bottom of a sand control completion. This is referred to as a sump packer and supports the screens during a gravel pack.

Packer Types
There are two basic types of packers: *production packers* and *service packers*. Production packers are either permanent or left in the wellbore for extended periods of time. They are used during normal operation of the well. Service packers are installed temporarily and removed from the wellbore once a specific operation is completed. All casing packers have a few things in common: an element package, mandrel and slips with wedges/cones. Most open hole packers do not include slips. Long inflatable element packages are used to seal against the open hole and to provide a mechanism to prevent movement. However, there are some mechanical open hole packer that do include slips.

Service and production packers are classified as *retrievable* or *permanent*. Retrievable packers are designed to be removed from the wellbore using a retrieval tool or work string manipulation. A retrieving tool may include a collapsible latch that fastens to the top of the packer. A straight pull will release the packer. Work string manipulation may include turning the pipe with a straight pull. Some retrievables cannot be reset in the well once released. They must be removed and serviced before they are used again. This servicing involves reinstalling new shear pins, element packages, backup shoes, etc. Other retrievable packers can be set and reset a number of times without tripping out of the hole. Permanent packers must be milled in order to be removed from the well. Thus, the permanent packer is rendered useless once removed.

Packers can be set in a number of ways: *mechanically, hydraulically, hydrostatically, or electrically*. With mechanical set packers, the work string is pushed, pulled, turned, or rotated to set. Hydraulically set packers utilize fluid pressure to shift pistons which transmit axial forces to wedges that expand the slips. Hydrostatic set packers employ a rupture disk that is burst by the static pressure in the wellbore at the required depth to regulate pressurization of the activation piston. They are useful in highly deviated wells in which typical packer plug setting is not possible.

Some packers have dual bores or even triple bores. These are used in wells in which commingling of formation fluids is not permissible.

Applications

<u>Hydraulic Fracturing</u>

The technique of hydraulic fracturing of formations in the oil and gas industry is very mature. Fracturing can be conducted by several different methods. In its simplest form, it may be performed through the casing. In this method, fluid is pumped from the surface and the entire wellbore is pressurized. Other methods that limit pressurization to a particular zone of interest or segment of the wellbore employ either a work string or coiled tubing. Packers are used in these methods to seal the annular space between the work string or coiled tubing and the borehole wall. A single packer can be used if it is necessary to only isolate the section of the well above the packer. Two packers are used to straddle a zone if it is desired to selectively pressurize a narrow interval in the well bore. Multiple packers with valving in the work string can be used if it is desired to sequentially perform stimulation of many zonal intervals in a single trip. In some instances it is necessary to first set the packer in the well and then stab the work string through the packer. In others, a special BHA with pre-assembled components is configured at the end of the work string for deployment.

Fracturing through casing does not require lowering tools downhole to perform the job. However, this technique exposes the main wellbore to pressure and increases the possibility of casing failure. Work string and coiled tubing approaches are considered to be safer as the upper casing can be isolated. Coiled tubing, when applicable, can be particularly cost effective because it can be more rapidly deployed than a work string (it is continuous rather than jointed) and coiled tubing unit costs can be less expensive than rig costs. On the other hand, it is generally available in smaller outer diameters and when used in conjunction with a packer is more susceptible to buckling in larger casing diameters.

The extension of fracturing from oil and gas wells to EGS wells must take into consideration several different factors. Temperature and the pressure required to fracture the hard rock are foremost of these concerns. The higher temperature in EGS wells has several potential impacts with regard to fracturing. If fracturing is to take place through the casing, the exposure of hot casing to cold fracturing fluids can result in damage due to thermal cycling. This thermal cycling, which causes the casing to expand/contract, can damage the bonds between the casing and cement. High well bore temperature can also impact the properties of fracture fluids. In the case of proppant assisted fracturing, the special fluids used to transmit proppant tend to break down at temperatures above 150 ^{o}C. Finally, the high temperatures also impact the design of the tools used during the fracture operation. If a packer is used with a work string or coiled tubing, the elastomeric seals of the packer must maintain mechanical integrity at the higher temperatures. High temperature often causes seals to soften and extrude allowing leakage.

With respect to pressure, if the fracture pressure is high and the wellbore is large, the packer differential pressure rating may be exceeded and failure may occur. Even if the element package is able to withstand the high pressures, the packer mandrel may collapse due to the applied radial forces on the elements. The use of a work string, as opposed to coiled tubing, may be required so that adequate weight can be set down on the packer.

CURRENT TECHNOLOGY & LIMITATIONS

<u>Cased Hole Packers</u>

The purpose of a packer, within the application of fracturing formations, is to provide a seal against the casing. This sealing prevents the casing above the packer from being exposed to high pressures which in some applications can exceed 15ksi. Most service companies have packers for large diameter casings up to 13-3/8”. There are also some so called “high pressure high temperature (HPHT)” 7-5/8” casing packers with pressure rating of 15ksi and temperature rating of 200^{o}C commercially available. Packers as large as 7” have been rated to temperatures up to 340^{o}C, with a differential pressure rating of

3ksi[13]. These high temperature packers are used in steam injection wells and geothermal production. Larger size packers, 11-3/4" and 13-3/8" are rated for lower temperatures (160^{o}C) with differential pressure ratings between 8-10ksi. Differential pressure capabilities tend to diminish in general with increasing packer diameter and temperature.

Permanent packers are preferred over retrievable packers for single zone fracturing because of the typically higher pressure rating. They often utilize slips above and below the element package or they can be set with cement. The permanent packer is also better able to handle cycling of temperatures. In oil wells, retrievable packers used for the fracture jobs are sometimes left in the well and used as production packers. The use of a packer (either permanent or retrievable) in EGS wells, however, would likely require an extra trip downhole to millout or retrieve the packer if the flow restriction created by its presence is not acceptable for production.

Packer development and use tends to be very application specific. Although most service companies offer standard product lines, there is a significant amount of customization that occurs within the industry to meet particular application needs. This would likely be the case with EGS. A more thorough assessment of this technology would require a more precise definition of the EGS service specification. This will be left to future investigation.

Open Hole Packers

Inflatable Design

Open hole packers are used for zonal isolations (water shut off, gas shut off, production control), single and multizone fracturing, testing (permeability tests, fracture tests, casing integrity), cementing operations, fishing, and injection. Open hole packers typically utilize inflated elements to seal against the open hole section. The inflatable design is usually required because of restricted wellbore above the open hole section. Because the hole is not cased, long elastomers are used to seal against the comparatively less uniform wellbore surface. This is especially important for fracturing. These packers are inflated using well fluid or cement. Open-hole packers are available for hole diameters between 8" to 9" with differential pressure ratings of 5000 psi and temperature of 180 ^{o}C. Larger sizes are also available. With respect to EGS wells, the temperature and pressure requirements are considered to be outside the current operating envelope of fluid inflatable packers according to service companies.

Swellable Design

Swellable packers might be a better solution for EGS open holes. Swellable packers utilize a long element that swells when it comes in contact with a hydrocarbon in the open hole. Water swellable packers are also available. The packer may take up to 20 days to set. Differential pressure ratings up to 7-10ksi with temperature ratings of 200 ^{o}C are commercially available. Lab tests of swellable packers have been successfully conducted at temperatures as high as 300 ^{o}C. The primary application for this high temperature

[13] http://www.weatherford.com/weatherford/groups/public/documents/general/wft004269.pdf

swellable packer is steam injection. The use of swellable components in EGS applications with multiple stimulation zones would require proper planning. Swellable packers are not deflatable (i.e. retrievable). Fracturing of multiple zones would therefore require that packers be spaced correctly at the outset. Shifting sleeves in the work string would then be used to provide selective access to the different zones. To remove the packer from the wellbore, it would have to be dragged out or milled out.

Mechanical Design

Mechanical open hole packers are set by manipulation of the workstring. Slips are used to anchor the packer to the wall. Using a mechanical packer for fracturing may not be a suitable application. Since the hole is not cased and cemented and the element package is short, fractures may form around and above the packer.

C.4 Casing drilling

Concept

The traditional process for construction of a well first drills the hole section to depth followed by removal of the drill pipe, insertion of the casing and cementing of the casing in place. As noted previously, time and cost associated with tripping to perform this operation can be substantial, especially for deeper wells. The concept of drilling with casing allows for drilling and casing with the same tubular. There are currently two types of systems (retrievable & non-retrievable) commercially available for drilling with casing. There are additional service costs associated with each system. Both use standard available casing.

Originally conceived to save money by minimizing tripping costs, the commercial success of casing drilling has also been attributed to an improved ability to deal with lost circulation as compared to conventional drilling. One manifestation of the latter benefit is thought to arise from the so-called “plastering” effect in which the narrower annulus between the casing and borehole wall, as compared to conventional drill pipe, is theorized to produce an impermeable filter cake that mitigates lost circulation effects. This plastering effect is also thought to strengthen the borehole wall and reduce wellbore stability issues. Other benefits of casing drilling include a more reliable method for running casing all the way to the bottom of the hole and safer casing handling. A rapidly growing service is the use of casing drilling equipment to run casing on conventionally drilled holes.

Modeling of casing drilling costs on conventional geothermal wells less than 2,500 m indicate that casing drilling will probably not offer much in the way of cost savings compared to conventional practice[14]. The potential benefit of reducing lost circulation problems in geothermal drilling is speculative since there are radical differences between typical oil and gas and geothermal lost circulation zones. The reduction in trip time is not as significant where much of the drilling is shallow.

[14] A.J. Mansure, “Advanced Drilling Concepts Final Report”, Internal Sandia Memo, 2008.

It is important to distinguish between cost savings when constructing the same well that can be drilled conventionally versus the impact of being able to construct a new well design not achievable by conventional technology. Casing drilling may offer the possibility for eliminating intermediate strings by controlling problems with wellbore stability in EGS wells greater than 3,000 m. This benefit could result in a significant cost savings.

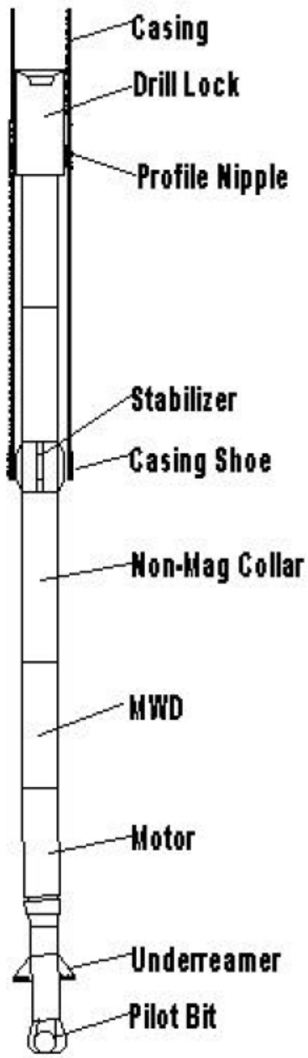
The two commercial available casing drilling systems are described below.

Casing while Drilling (CwD) Systems

Retrievable System

Tesco provides drilling with casing systems that are retrievable for both vertical wells and directional wells. The standard components of the system for vertical wells are as follows: casing, casing profile nipple, casing shoe, casing stabilizers, drill lock assembly (DLA), under-reamer, and drill bit. The casing, casing profile nipple, casing stabilizers and the shoe make the casing string. The casing profile nipple is connected to the casing a certain distance above the casing shoe. This profile nipple enables the system to be retrievable. The casing stabilizers assist with deviation control. The bottom hole assembly (BHA) consists of an outer and inner string (Figure C-8). The inner BHA consists of the DLA, stabilizers, and spacer collar. The DLA is latched into the casing profile nipple. Thus, the DLA is completely enclosed in the casing string. The DLA is used to transmit torque from the rotating casing to the drill bit and to transfer axial loads (weight down) on the drill bit. Elastomers on the DLA external surface seal against the casing inside surface. This allow for pumping drilling fluid down the casing to the drill bit. A spacer collar is connected to the bottom end of the DLA. The spacer collar extends out below the casing shoe. Stabilizers above the spacer collar are used to stabilize the portion of the spacer collar that is located in the casing string. The external BHA consists of the under-reamer, spacer collar, stabilizers, and drill bit. The external BHA is attached to inner BHA spacer collar (the end that extends past the casing shoe) by the under-reamer. The under-reamer is specifically designed to be used in drilling with casing systems. It opens the pilot hole (created by the drill bit) by 50%. The annular space between the casing outer surface and the wall of the enlarged hole is cemented. Below the under-reamer is another collar with stabilizers. The drill bit used is typically a PDC type.

Operation of the system first requires assembly of the inner and external BHAs by latching the internal section into the casing profile nipple. The casing is then lowered to bottom and rotated to commence drilling. Torque and axial loads are transferred from the casing to the drill bit by the DLA. While drilling, fluid is pumped down the casing, through the DLA, spacer collars, and under-reamer to the drill bit. The fluid is returned to surface in the annular space between the casing outer surface and the borehole wall. Once the casing point is reached, a wireline retrieving tool is deployed. The retrieving tool releases the DLA from the casing profile nipple. The BHA along with the DLA is then brought to surface. The drill bit used on the BHA is small enough to pass through the casing string. The casing is then cemented. The next well interval is then ready to be drill in the same manner. Available sizes of casing drilling systems range from 4-1/2” to 13-3/8”.



C-8 Casing drilling bottom hole assembly

The directional system is very similar to the vertical drilling with casing system. A positive displacement motor (PDM) is placed below the DLA inside of the casing (above the under-reamer). Below the under-reamer is an MWD system with a rotary steerable system (RSS) above the drill bit. The directional system is considerably longer than the vertical system.

Non-Retrievable System

The system provided by Weatherford is a non-retrievable type system. A *drillable* drill bit is placed at the bottom of the casing string. No under-reamer is used in this system. The drill bit is able to open the hole sufficiently to allow for cementing of the casing after reaching depth. Once the casing is drilled to the required casing point, a ball is pumped down and lands on a ball seat in the drillable drill bit. Pressure is applied down the casing and the drill bit is shifted so that large flow ports allow for communication with the open hole. Cementing the casing then takes place. The next casing string then is run with a drill bit on bottom of it. The previous drill bit is drilled out and the wellbore drilling continues. With this system directional drilling is not possible.

C.5 Expandable Tubulars

Types of Expandable Technology

Expandable technology is typically classified as follows:

- Expandable Slotted Tubulars
    - Screens
    - Liners
- Expandable Solid Tubulars
- Expandable Tubular Systems
    - Open Hole
    - Cased Hole

Description of Expandable Tubular System

An expandable tubular is essentially a liner (pipe) that has been plastically deformed (below the ultimate yield) while in the well. The typical system consists of a liner, inner tube, expansion cone, shoe, and dart (plug). The liner used is similar to API L-80 and utilizes elastomeric material on the outer surface for sealing integrity when placed in either an open hole or an existing casing. Prior to tripping in the hole, an inner tube is connected to the expansion cone. The expansion cone is then pulled thru the bottom of the pipe such that the cone has plastically deformed the pipe a short distance. A shoe, with a thru hole, is connected to the bottom of the liner, and thus the cone is wedged in the liner and encapsulated by the shoe. The system is then picked up and lowered to depth. It is worth mentioning that the liner is run with the pin thread in the up position. This prevents the separation of threaded connection of a mating liner. Once the required depth is reached, a dart is pumped down from the surface through the inner tube. The dart lands in the hole of the shoe and a plug is formed. Pressure is then applied down the inner tube and the expansion cone begins to travel upward due to hydraulic pressure. Since the liner ID is smaller than the cone OD, as the cone travels upward, the liner begins to expand and plastically deform. As the cone travels upward the expanding liner is filled with pressurized fluid. The cone travels through the entire length of the liner and exits at the top of the liner. The cone and inner tube are removed from the hole and a drill bit is deployed to mill out the shoe.

Typical Open Hole Applications

Drilling Liner

When a well is drilled, the diameter of the wellbore decreases in stages as depth increases. This is referred to as a telescoping effect. One reason this effect occurs is because as drilling reaches certain depths, the formation which is being drilled may be weak and could fracture under the pressure of the drilling mud. To prevent the formation from being damaged, casing is run in the hole and cemented in place. This isolates the formation from the drilling mud pressure. However, to continue drilling, a drill bit smaller than the previous drill bit must be used in order to pass through the last installed casing. The reduction in hole size can be between 15-20%.

By using an expandable liner in the next casing interval, the hole size can be conserved. The hole below the existing casing is drilled and an under reamer is used to enlarge the pilot hole. The expandable liner assembly is run into the hole. The OD of the cone assembly is the drift diameter of the last casing string. Prior to expanding, the liner is cemented. Afterwards the liner is expanded. Elastomeric seals at the top of the expanded liner provide pressure integrity by sealing on the inside surface of the previous casing string. The seals also anchor the liner to the last casing string. Depending on the casing size and weight, the expansion ratio of the liner ID can range from about 3-15%.

For EGS wells, using expandable liners can decrease upper interval hole diameters while still achieving the desired production zone hole diameter.

Monobores

The constructing of a well with a single diameter (after the surface casing) is the target of many expandable tubular companies. There have been some field tests that proved successful. This of course would reduce cost of EGS wells by reducing the size of casing at the surface and achieving required hole size in the production zone.

Lost Circulation

If there is lost circulation occurring in an open hole section, the expandable liner can be used to straddle the zone. In this case, the liner has sealing elements at the top and bottom. The liner is expanded in the open hole region where the problem exists. The liner anchors to the formation by cladding against the formation and with the elastomers. No tie back to the last casing string is needed. This can be accomplished in a wide range of hole sizes.

With regards to drilling EGS wells, one consideration is the temperature rating of the liner elastomers. Most common temperature ratings are around 204 ^{o}C. Some liners with temperature ratings of about 340 ^{o}C have been run in steam injection wells in Canada. Using an expandable liner in an open hole EGS well with short circuits may be a viable solution. Although flow area is reduced the reduction may not be as detrimental as installing packers.

Window Exits

If drilling has to be side tracked thru a milled window, an expandable liner could be used. The window must be cleaned out and a proper whipstock design is required. By having to drill a side track a hole size could be lost. Using an expandable helps to preserve hole size in the hole from the exit.

Typical Cased Hole Applications

Casing Repair/ Perforated Zone Isolation

The damaged portion of a casing can be repaired using a cased hole liner. The casing is cleaned out. The liner is run down to depth and expanded. The liner incorporates elastomers to seal above and below the damaged casing region. The liner also used cladding to seal in the damaged casing.

DISTRIBUTION

1 Robert Swanson
ThermaSource
3883 Airway Dr. Suite 340
Santa Rosa, CA 95403

1 Louis Capuano, Jr
ThermaSource
3883 Airway Dr. Suite 340
Santa Rosa, CA 95403

1 John Finger
323 Bryn Mawr Dr. SE
Albuquerque NM 87106

1 Ed Wall
U.S. Department of Energy - Geothermal Technologies Program
Office of Efficiency and Renewable Energy
1000 Independence Ave. S.W.
Washington, DC, 20585

1 Raymond LaSala
U.S. Department of Energy - Geothermal Technologies Program
Office of Efficiency and Renewable Energy
1000 Independence Ave. S.W.
Washington, DC, 20585

1 Jay Nathwani
U.S. Department of Energy - Geothermal Technologies Program
Office of Efficiency and Renewable Energy
1000 Independence Ave. S.W.
Washington, DC, 20585

1 Arlene Anderson
U.S. Department of Energy - Geothermal Technologies Program
Office of Efficiency and Renewable Energy
1000 Independence Ave. S.W.
Washington, DC, 20585

1 Raymond Fortuna
U.S. Department of Energy - Geothermal Technologies Program
Office of Efficiency and Renewable Energy
1000 Independence Ave. S.W.
Washington, DC, 20585

1 Alan Jelacic
U.S. Department of Energy - Geothermal Technologies Program
Office of Efficiency and Renewable Energy
1000 Independence Ave. S.W.
Washington, DC, 20585

1 Professor Chuck Kezar
Lyndon State College
PO Box 129 Morgan, VT 05853

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