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Abstract

This report documents the key findings from the Reservoir Maintenance and Development (RM&D) Task of the U.S. Department of Energy's (DOE), Geothermal Technologies Office (GTO) Geothermal Vision Study (GeoVision Study). The GeoVision Study had the objective of conducting analyses of future geothermal growth based on sets of current and future geothermal technology developments. The RM&D Task is one of seven tasks within the GeoVision Study with the others being, Exploration and Confirmation, Potential to Penetration, Institutional Market Barriers, Environmental and Social Impacts, Thermal Applications, and Hybrid Systems. The full set of findings and the details of the GeoVision Study can be found in the final GeoVision Study report on the DOE-GTO website. As applied here, RM&D refers to the activities associated with developing, exploiting, and maintaining a known geothermal resource. It assumes that the site has already been vetted and that the resource has been evaluated to be of sufficient quality to move towards full-scale development. It also assumes that the resource is to be developed for power generation, as opposed to low-temperature or direct use applications. This document presents the key factors influencing RM&D from both a technological and operational standpoint and provides a baseline of its current state. It also looks forward to describe areas of research and development that must be pursued if the development geothermal energy is to reach its full potential.

ACKNOWLEDGMENTS

We would like to thank the ‘visionaries’ who provided incredibly constructive and useful feedback and input into the GeoVision Study. Their insight and knowledge helped insure the success and suitability of the information across all the Tasks. We would also like to thank the DOE-GTO, particularly (in no particular order) Lauren Boyd, Zach Frone, Tim Reinhardt, Holly Thomas, and Jeff Winick for their financial and managerial support in the Study’s execution. Their patience, guidance, and insight contributed significantly to the quality of this report. Finally, we need to thank the research teams of the other Tasks, who provided many useful comments and suggestions.

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NOMENCLATURE

Abbreviation	Definition
BETA	Baker Hughes Experimental Test Area
BHA	Bottom Hole Assembly
BOE	Barrel of Oil Equivalent
bps	bits per second
CBR	Continuous Build Rate
CDP	Conventional Drill Pipe
CED	Chemical Enhanced Drilling
COTS	Commercial Off the Shelf
CPI	Consumer Price Index
DOE	Department of Energy
DWOP	Drilling While on Paper
EGS	Enhanced Geothermal System
GETEM	Geothermal Energy Technologies Evaluation Model
GRWSP	Geothermal Reservoir Well Stimulation Program
GTO	Geothermal Technologies Office
HDR	Hot Dry Rock
HF	Hydraulic Fracturing
HS	Hydraulic Shearing
IDP	Insulated Drill Pipe
JAD	Jet-Assisted Drilling
JAS	Joint Association Survey
LCM	Lost-Circulation Material
LCOE	Levelized Cost of Electricity
LED	Laser Assisted Drilling
LLNL	Lawrence Livermore National Laboratory
LWD	Logging While Drilling
mcf	million cubic feet
MMS	Mixed Mechanism Stimulation
MPT	Mud Pulse Telemetry
MWD	Monitoring While Drilling
NDT	Non-Drilling Time
NETL	National Energy Technology Laboratory
O&G	Oil and Gas
P2P	Potential to Penetration
PDC	Polycrystalline Diamond Compact
PTS	Pressure-Temperature-Spinner
RM&D	Reservoir Maintenance and Development
ROI	Return on Investment
SME	Subject Matter Expert
TCC	Torque Control Components
TS	Thermal Stimulation
WCS	Well Cost Simplified
WDP	Wired Drill Pipe

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1. INTRODUCTION

In 2016 and 2017, the U.S. Department of Energy (DOE), Geothermal Technologies Office (GTO) conducted the Geothermal Vision Study (GeoVision Study) with the objective of identifying the challenges and actions necessary to significantly increase opportunities for U.S. geothermal energy production. More specifically, the GeoVision Study had the objective of conducting analyses of future geothermal growth based on sets of current and future geothermal technology developments. Within the Study, there are seven separate tasks; Exploration and Confirmation, Reservoir Maintenance and Development (RM&D), Potential to Penetration (P2P), Institutional Market Barriers, Environmental and Social Impacts, Thermal Applications, and Hybrid Systems. The full set of findings and the details of the project can be found in the final GeoVision Study report on the DOE-GTO website (DOE 2017).

This report documents the key findings from the RM&D Task that were used to inform the final GeoVision Study report. For the purpose of the GeoVision Study, RM&D refers to activities associated with developing, exploiting, and maintaining a known geothermal resource. It assumes that the site has already been vetted and that the resource has been evaluated to be of sufficient quality to move towards full-scale development. It also assumes that the resource is to be developed for power generation, as opposed to low-temperature or direct use applications. There is considerable cross-over between RM&D and some of the other GeoVision Tasks (particularly the Exploration Task) since many of the same technologies (e.g. logging tools, geophysical tools, drilling hardware, etc.) are used during those other phases as during the RM&D phase.

This report discusses the key technologies associated with RM&D and the potential for either reducing costs and/or increasing reservoir performance. The information herein relies heavily on the published literature as well as input from several subject matter experts (SME's). The subjects covered in the report represent the subjects that have the most potential for improving the current state of RM&D, which is determined by the impact they have to accelerate and deepen the use of geothermal energy in the general market. As with the cross-over between RM&D and the other tasks, there is also cross-over amongst the technologies available for RM&D. An example of this is the importance of high-temperature electronics, which many other technologies such as logging-while-drilling (LWD) and monitoring-while-drilling (MWD), rely on. Thus, this report provides a view of these connections to give the reader a better understanding of the integrated complexity of the technological hurdles that RM&D faces.

A key objective of the RM&D Task was to supply the default and projected values to the P2P task for use in the Geothermal Electricity Technology Evaluation Model (GETEM; Entingh, et al. 2006) in support of their market penetration calculations. Of specific note are the drilling cost curves that represent a range of technological advances, from today's current state-of-the art values to an 'Ideal' scenario that assumes we are able to solve all of the technology gaps with respect to drilling.

The initial intent of this task was to look at RM&D from four separate scenarios; 1) hydrothermal in crystalline rock, 2) hydrothermal in sedimentary rock, 3) enhanced geothermal systems (EGS) in crystalline rock, and 4) EGS in sedimentary rock. It became quickly apparent that RM&D subject matter is not easy to categorize due to the fact that there are many more commonalities than there are differences between the scenarios. Thus, unless specifically called out, the content of this report is applicable across the full range of RM&D environments. It should also be noted that because maintenance involves a set of management decisions, the terms 'maintenance' and 'management' are sometimes used interchangeably throughout this report.

This report is broken into seven sections, including this introduction. The second section provides a high-level description of the challenges to RM&D and the importance of the concept of risk on geothermal energy development. Sections three and four address material associated with the Development and Maintenance phases, respectively. The fifth section presents material on other subjects associated with RM&D that do not fit neatly under the other categories. The sixth section is a discussion that summarizes the key findings of the RM&D Task and the last section provides a bulleted list of what we believe are the key take-away messages of this work.

2. CHALLENGES AND RISK

Two objectives must be met if geothermal energy development is going to meet its full potential; reduce costs and reduce risk. Underlying those objectives are a set of technical challenges that are conceptually easy to express but immensely difficult to solve. Those technical challenges include developing equipment that can withstand harsh geothermal environments, optimizing reservoir operations, establishing and maintaining flow through a suitable volume of rock between injection and production wells for EGS systems, and advancing data, modeling, and analysis capabilities. The collective capabilities from meeting these technical challenges will enhance RM&D, and geothermal energy development in general, to the point where it can become an integral piece of the U.S. energy generating portfolio.

It is well known that exploration and development costs are a limiting factor in geothermal energy production. Unique to geothermal energy is the fact that the resource is extremely heterogeneous in its spatial distribution and ease of access. With the exception of obvious surface features, such as hot springs, volcanic vents, and the like, gaining access to a geothermal resource is time-consuming and expensive. In this regard, geothermal energy has much in common with the fossil fuel industry, who must explore the sub-surface to access the energy source of interest. This is in contrast to other renewable energy sources (wind, solar, hydro) where the resource is easy to measure and characterize and the risks are relatively low.

Given the commonalities between geothermal energy and fossil fuels, particularly oil and gas (O&G), it would seem that O&G technologies could be easily applied to geothermal. However, as is discussed in detail below, this is not necessarily the case. Besides the differences in the drilling environment between the two industries, there is a large difference in economics in that the energy density upon accessing their respective source is smaller for geothermal than it is for O&G.

According to the US Energy Information Administration (EIA 2017), the average production per day of oil and natural gas for new wells in March 2017 was 700 barrels of oil and 3,500 million cubic feet (mcf) of natural gas, respectively. Using the standard estimate that a barrel of oil equivalent (BOE) and 6000 cubic feet (6 mcf) of natural gas are equivalent to approximately 1,700 kWh of energy, a new oil well produces about 50 MW of power and a new natural gas well produces 40 MW of power. Conversely, the median geothermal well capacity is about 7 MW (Sanyal and Morrow 2012). This makes the initial short-term cost of developing geothermal energy 6 to 7 times more expensive than O&G. Over the long-term, this relationship can even itself out or even reverse itself due to the fact that the production rates of O&G wells usually drop off over time. However, it still remains that the return on investment (ROI) for drilling O&G wells is much quicker than geothermal, which given the time value of money makes investment in O&G more attractive, even for wells that are short-lived.

The uncertainty of characterizing the source and in predicting the short- and long-term thermal and economic performance a priori, contributes significantly to the financial risk of geothermal development. The classic definition of risk is the probability of an event occurring times the consequence of the event (Figure 1). The concept of risk underlies the entire insurance industry, who are able to reduce risk by spreading it out across thousands of clients. For energy extraction, O&G companies are able to do this by spreading risk across hundreds or even thousands of wells per year.

Unfortunately, geothermal energy development is currently done on a project by project basis, so the opportunity to spread risk across multiple projects is minimal.

From an investment point of view, an investor or developer in geothermal energy needs to know if they can receive a return on their investment. To illustrate this, assume that we have perfect knowledge of a particular geothermal field; we know the temperature at depth, the exact fracture pattern, the injectivity, productivity, and so on. In this case, an investor or developer knows exactly how much money they can spend on developing the resource and still make a profit. In fact, with this type of certainty, they can design their system to optimize their profits. Since the exact performance of the system is known, the exact net income is also known (again, assuming we have perfect knowledge of future energy markets) and there is no uncertainty and hence no risk.

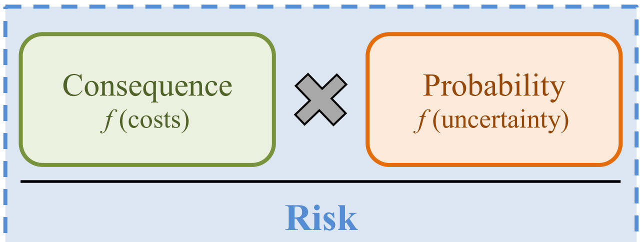

Figure 1 - Risk is the product of the consequence of an event and its probability of occurring. In geothermal energy production, consequence is a function of risk and probability is a function of uncertainty thus overcoming the technological hurdles for reducing costs and uncertainty also reduces the risk to developers.

This is obviously not the case in 'real life'. With every added uncertainty, the probability of not achieving a return on a particular investment goes up, as does the risk (Lowry, et al. 2012). This concept holds true for uncertainties in any process (e.g., success of drilling a well, stimulating a reservoir, maintaining long-term production, etc.) associated with developing a geothermal energy resource and need not be applied to just financial investments, although ultimately, that is what RM&D is all about: ensuring a return on investment.

Uncertainties can have varying degrees of impact depending on the influence of the underlying variable on the evaluation metric (e.g. LCOE, thermal drawdown, etc.). Within a complex set of integrated systems such as those that make up a geothermal project, uncertainties in a fundamental parameter can either magnify, attenuate, or not affect the uncertainty in the evaluation metric as it propagates through the various systems (e.g., uncertainty in injectivity/productivity impacts pumping requirements, which impacts O&M costs, which impacts LCOE). Understanding these types of dynamics is of extreme importance for RM&D because it allows efforts to be targeted on reducing the uncertainties that have the greatest impact.

Taken together, the challenges of reducing costs and uncertainty are intimately connected through the concept of risk in that costs control the consequence (lower costs means less money to lose) while uncertainty controls the probability. As is discussed in the sections below, advancements in technology and methodology will impact both of these issues.

3. DEVELOPMENT

3.1. Drilling

The main well types for geothermal energy production are slimholes, temperature gradient holes, core holes, and production and injection wells. For the RM&D task, the focus is on production and injection wells since the other well types are mainly used during the exploratory phases, although there may be some utility for using slimholes for monitoring and maintenance. There are numerous documents and studies that provide historical context, technological assessments, and/or cost analyses for geothermal drilling (e.g., Tester, et al. 2006; Polsky, et al. 2008; Bush and Siega 2010; Finger and Blankenship 2010; Sanyal and Morrow 2012; Lukawski, et al. 2014; Yost, et al. 2015; DOE 2016; Lukawski, et al. 2016). This section applies the lessons and data from those and other studies to examine geothermal production and injection well drilling from a gaps analysis point of view whereby existing engineering problems are identified and their potential solutions are presented. Since geothermal well drilling is all about controlling costs, estimates of the economic benefit of solving those problems is also provided.

3.2. Cost Factors

Drilling costs can account for 50% or more of the total capital costs for a geothermal power project (Tester et al. 2006), which makes reducing drilling costs one of the most important factors for geothermal energy production to become economically viable across a wide range of geothermal environments. Controllable factors that affect drilling costs include well design, resource depth, and drilling efficiency while the uncontrollable factors are external to the drilling process and include O&G prices, rig availability, and financing and labor costs (Mansure and Blankenship 2013; Lukawski et al. 2014; Yost et al. 2015).

Prior to 2004, well drilling costs were mostly stable, but were also below the levels required to maintain a sustainable drilling industry (Mansure and Blankenship 2013). Rig rates during that time were actually below the rate of return required to borrow money from the bank, meaning that banks were leery of investing in new rigs (Mansure, et al. 2006). Consequently, the drilling industry survived by maintaining the rig fleet using parts from excess rigs left over from the oil boom in the late 1970's and early 1980's. Once the supply of spare parts ran out, along with other factors such as O&G prices, drilling prices increased exponentially at rates much higher than the consumer price index (CPI). This sudden rise in costs is shown in Figure 2 where the Bureau of Labor Statistics (BLS) Production Price Index (PPI) serves as an analog for drilling costs (Mansure and Blankenship 2013) and is compared to the CPI. What is apparent is that a new, but higher baseline that now reflects an industry sustaining price point has been established. While it is tempting to look at the O&G industry for analogs to determine geothermal drilling costs, geothermal drillers usually face one or more challenges that O&G drillers do not (Finger and Blankenship 2010):

1. High temperature environment
2. Geologic environments that are abrasive, fractured, and have high rock matrix strength
3. Corrosive groundwater chemistry
4. Larger diameter boreholes

Because of the differences between drilling O&G and geothermal wells, the costs of each type cannot be directly compared (Lukawski et al. 2014). However, due to the large number of recorded O&G wells versus geothermal wells (>100,000 versus < 1000 for wells on public land), O&G drilling data have been used to develop cost indexes of various complexity to predict geothermal drilling costs as a function of depth (e.g., Augustine, et al. 2006; Mansure et al. 2006; Tester et al. 2006; Polsky et al. 2008; Sanyal and Morrow 2012; Mansure and Blankenship 2013). Augustine et al. (2006) used the Joint Association Survey (JAS) drilling cost data to develop a cost index for O&G wells and compare those values to known EGS and hydrothermal costs showing that the geothermal wells are 2 to 5 times costlier than O&G wells at similar depths. The results of these indexes are useful for gaining insight into the key factors and temporal dynamics that drive drilling costs but may be of limited utility when used as predictors of a particular well because they do not consider the complexity of the drilling environment, the experience of the drilling crew, nor any other cost factors other than depth (Lukawski et al. 2014). More recent studies have begun to focus on uncertainties in the cost factors to develop probabilistic estimates of drilling costs that highlight their variability (Mansure et al. 2006; Lentsch and Schubert 2013; Silverman, et al. 2014; Yost et al. 2015; Lukawski et al. 2016). In all cases, these studies show that the variability of drilling cost increases with depth and that the costs can vary by more than ±50% of the deterministic estimates.

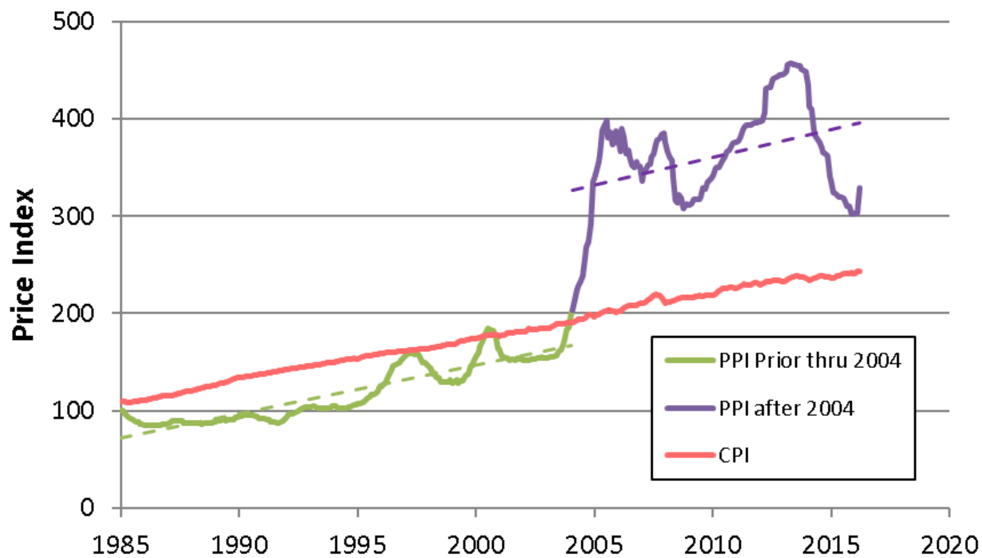

Figure 2 - Bureau of Labor Statistics Production Price Index (PPI) versus consumer price index (CPI). Dotted lines show the pre- and post-2004 trends. Figure is updated from Mansure and Blankenship (2013).

3.3. Drilling Cost Curves

A key objective of the drilling cost analyses is to provide drilling cost curves to the P2P task that reflect various degrees of technological advancements. The first step establishes the current state-of-the-art for a typical well, which we use as the baseline. The challenge was to condense the complexity in drilling performance into a tractable set of scenarios. In doing so, for the sake of simplicity, important parameters and relationships tend to be obscured but despite this limitation, the final results highlight the significant aspects of well drilling that can drive costs down with further research and development (R&D).

Thus, the cost curves produced for the P2P analysis are not intended to reflect the current cost of drilling a particular well but rather are intended to highlight the current state of the art and the sensitivity of the total well cost to improvements in major aspects of the drilling and completion effort. They are also general in nature meaning that variables such as rock type, bit type, and drilling technology are not explicitly accounted for. While considerable effort has gone into ensuring the accuracy of significant cost drivers such as rig costs, material pricing, etc., the variability in the numerous cost factors prevents the curves from being ‘current’. They are however, believed to be representative of the costs one would encounter across a wide-range of conditions and drilling environments.

To simplify the development of well cost scenarios, costs are grouped into four different categories:

1. Drilling
2. Flat Time
3. Trouble Time
4. Additional Time

The activities included in each category differ somewhat from traditional definitions, but represent more logical groupings with regards to the well cost input parameters. Material costs are grouped into the activity with which they are associated. Pairing activity and related material costs simplifies the process of making modifications to the assumed baseline, as opposed to grouping material costs into a separate category.

Activities grouped into the ‘Drilling’ category are limited to those related to extending the hole, such as rotating on the bottom, tripping drill pipe, and handling the bottom hole assembly (BHA) to replace damaged bits. Also included are drill bit and BHA component costs, directional equipment costs (for scenarios that include directional wells), and related labor costs.

‘Flat Time’ includes all planned activities and associated costs that do not directly contribute to extending the hole, such as running casing, cementing, and logging. ‘Trouble Time’ incorporates any activity and associated costs that arise from adverse hole conditions or unexpected failures. Among the most prevalent of these is lost circulation.

The ‘Additional Time’ category includes mobilization/demobilization, site preparation, pre-spud engineering, and wellhead equipment. Since these costs are typically less than 10% of the total well cost it makes them less impactful targets for R&D and thus the costs in this category are held constant across all the well scenarios described below.

Baseline values for rate of penetration (ROP) and bit life are based on an analysis of the drilling records from seven deep ($12{,}000^{+}$ ft) wells that were drilled in Australia from 2003 to 2010 as part of that country’s effort to develop EGS. Each of the wells was thoroughly documented, including detailed data on bit performance (bit life, ROP, and formation being drilled). Six of the wells (Habanero 1, Habanero 2, Habanero 3, Habanero 4, Jolokia 1, and Savina 1) were drilled in the Cooper Basin of South Australia while the seventh, Paralana 2, is almost 180 miles away in lithology that is noticeably different. Habenero 1 and 2 used a smaller-diameter profile with bottom-hole diameters of 6”, whereas the others have an 8.5” diameter at terminal depth. Each of the wells was targeted to end in a granite basement formation, although Savina 1 barely reached it before the well was abandoned after severe drilling problems.

The daily drilling reports for each well were examined to eliminate some of the bits from statistical analysis because they were used for cleaning junk, for wiper trips, or for other functions that did not represent ‘normal’ drilling. Each bit analyzed drilled a given interval length in a certain number of hours. The interval length divided by the number of hours is the ROP for the interval. The number of hours is taken to be the bit life, although there were a few cases in which the bit was not fully worn and was pulled for other reasons.

To determine the baseline ROP, the data are plotted as a cumulative distribution function and the 90th percentile value was chosen (Figure 3), which produced an ROP of about 30 ft/hr. The 90th percentile was chosen as an appropriate value for the current state-of-the-art, baseline scenario. After discussions within the project team the 30 ft/hr was scaled down to 25 ft/hr, which is at the 88th percentile.

The same approach is used to determine the baseline value for the bit life. However because of the correlation between bit life and ROP (an increase in the ROP correlates to an increase in the bit life with respect to footage drilled), the baseline value was lowered to the 70th percentile, which returned a value of 65 hrs (Figure 3). After discussions within the project team, this value was reduced to 50 hrs, which is at the 58th percentile.

With regards to variability with depth and bit size, the Australian data show a slight correlation with bit size and a stronger correlation with depth (Figure 4). However, because the cost curves are meant to be representative across all lithology's and depths as well as the noisiness in the correlations, no adjustments were made to the ROP as a function of bit size or depth.

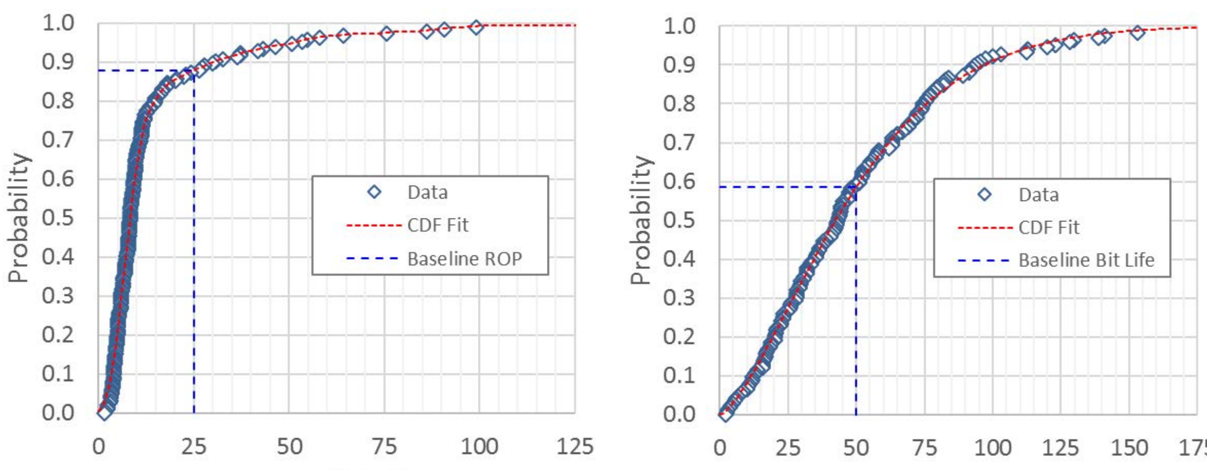

Figure 3 – Cumulative distribution function of the rate of penetration and bit life across all records for seven EGS wells drilled in Australia from 2003 to 2010 (Habenero 1, 2, 3, & 4, Jolokia 1, Savina 1, and Paralana 2). The blue dotted lines indicate the location of the baseline values used in the cost curves.

Because of the importance of the ROP and bit life with respect to the drilling cost (Lukawski et al. 2016), the baseline values were compared to values in the literature to insure that they are reasonable and representative. Rowley, et al. (2000) report an average ROP of 13.0 – 16.4 ft/hr for geothermal wells "drilled world-wide" but then show in their study that the use of percussion hammer drilling can increase those values by 10 to 15 times. During field tests in the hard-rock environment of the Chocolate Mountains in California, Raymond, et al. (2012) achieved rates of 10-20 ft/hr and an average bit life of 40 hours for roller-cone bits and 20 to 27 ft/hr for polycrystalline-diamond-compact (PDC) bits. Polsky et al. (2008), in their EGS well technology report, use ROP's of 12-18 ft/hr, which includes time for making connections, and bit life's of 40-120 hours for a hypothetical EGS well in the Clear Lake field in California. For their 'steam well' case study, Finger and Blankenship (2010) indicate ROP's of 17 to 95 ft/hr and bit life's of 10-24 hours. In their study showing the improvement in drilling performance of self-adjusting PDC bits, Jain, et al. (2015) use numerical simulations to show ROP's of 90 ft/hr in sandstone and 50 ft/hr in dolomite. Finally, the U.S. Department of Energy state in their production drilling and well completion report that ROP's 'vary tremendously', with rates in 'medium' formations for roller cone and PDC bits ranging from 5 – 160 ft/hr (DOE 2016). They also indicate an average bit life of 65 hours. Given these values, we believe that the use of 25 ft/hr and 50 hours as the baseline scenario for the drilling cost curves are well justified, especially when one considers that the values are meant to reflect effective, current state-of-the-art values across all well types and lithology's.

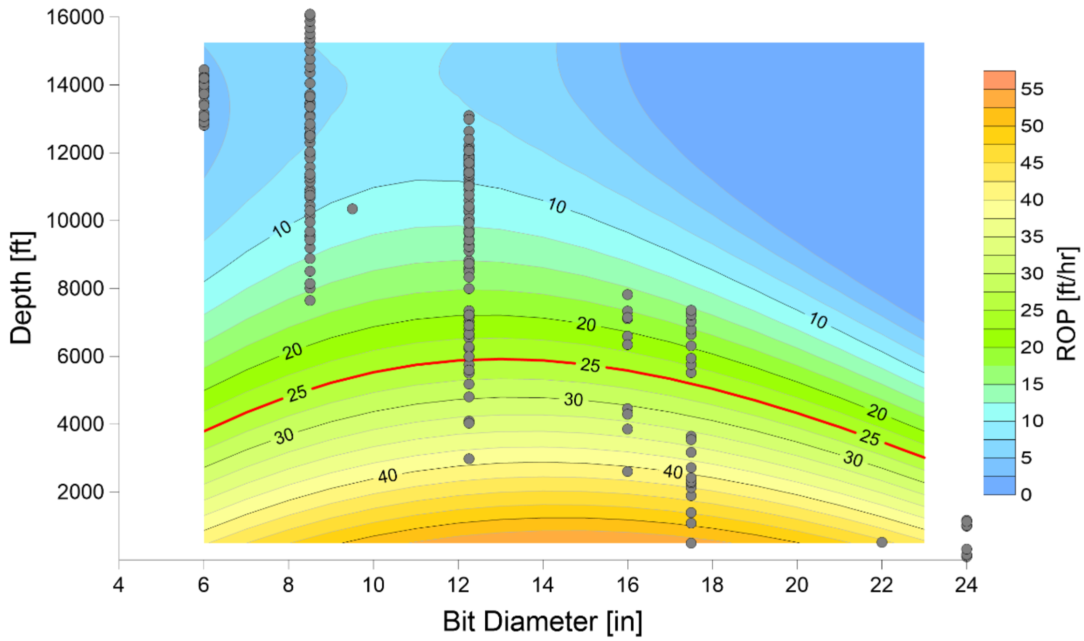

Figure 4 - ROP as a function of bit diameter and depth for the seven Australian wells. The depths are based on the average depth of each interval and are further consolidated into depth bins of 1000 ft. The gray dots represent the location of the interval data.

The well design model in GETEM was leveraged to determine the casing schedule for each of the wells. This was done to maintain consistency with the use of GETEM in calculating the LCOE in the P2P task. The GETEM model uses the following criteria to set the number of cased intervals:

1. Minimum number of intervals is 3
2. If depth is between 3-5 kilometers, number of intervals is 4
3. If depth is greater than 5 kilometers, number of intervals is 5
4. Number of intervals can be input, but must be >3

The only changes made to the GETEM casing schedules was the 30-inch diameter surface casing recommended on small diameter, deep wells (5000-6000 meters). The initial wall thickness calculated by GETEM is 1.687 inches, which was manually reduced to a more realistic wall thickness value of 0.687 inches. This is also the thickness recommended by GETEM for the large diameter, deep wells.

Another important assumption is the daily rig rate. GETEM estimates the rig rate from the required hook load to run casing, with additional provisions for fuel consumption and rig related rentals. These provisions reflect the nominal size and rig power requirements that in turn affect rig rates and thus the rig rate varies with depth and well diameter. The rates are given in Table 2 below.

Finally, an effort was made to standardize the construction of the wells regardless of depth, so the surface casing for all wells is set at 1,000 feet to account for regulations concerning protection of aquifer zones shallower than the targeted production interval. At the other end of the well, the production zone is also assumed to be 1,000 feet in length.

3.4. Well Cost Curve Scenarios

To generate the curves, the proprietary Well Cost Simplified (WCS) model from Sandia National Laboratories was used to calculate the cost of drilling wells for four scenarios that reflect a range of technologies from the current state-of-the-art baseline to the highest foreseeable potential. The four scenarios are named the Baseline, Intermediate 1, Intermediate 2, and the Ideal scenarios. Within each scenario, wells reflecting small and large completion diameters as well as vertical and horizontal orientations are considered, resulting in 16 separate scenarios. The model inputs for each scenario are listed in Table 1.

Table 1 - List of the differentiating inputs to the WCS model for the various scenarios. Where appropriate, (1) = Baseline, (2) = Intermediate 1, (3) = Intermediate 2, and (4) = Ideal.

Category / Parameter		Value
Target Depth [m]		1000 m to 7000 m, at 500 m intervals
Total Depth [m] (Vertical only)		1152.4 m to 7152.4 m, at 500 m intervals
Production Zone Hole Diam. (GETEM defaults)		Small (8.50 in), Large (12.25 in)
Production Zone Length [m]		304.8 m (1000 feet)
Completion / Orientation		Vertical – Open Hole, Deviated – Perforated Liner
Drilling Costs	**ROP [ft/hr]**	(1) 25; (2) 50; (3) 75; (4) 100
	Bit Life [hr]	(1) 50; (2) 100; (3) 150; (4) 200
	CBR* [deg.]	(1) 3; (2) 10; (3) 20; (4) 30
Flat Time	**# Cased Intervals**	(1) 3-5 (GETEM default); (2) Reduce by 1; (3) Reduce by 2; (4) Mono-bore
	Mud Costs	(1) Default; (2 & 3) Drill half with mud, half with air or water; (4) Drill all with air or water
	Wireline Logging	(1) Log all except surface interval; (2) Log only production interval; (3 & 4) No wireline, use logging while drilling (LWD)
Trouble Time	**Contingency**	(1) 15%; (2) 10%; (3) 5%; (4) 0%

***Continuous build rate**

The target depth represents the depth of the target reservoir temperature. The total depth applies only to the vertically oriented wells and reflects the assumption that the production zone is centered at the target depth. When comparing vertical to horizontal production zones, specifying the same depth for both well types is not a direct comparison unless the center of the production zone in the vertical well coincides with the terminal horizontal depth (Figure 5). Making this distinction ensures that the average reservoir temperature from both well types is the same, assuming also that production from the vertical well is uniformly distributed across the production zone.

For the horizontal well configurations, the build angle changes continuously to 90° (horizontal) beginning from the bottom end of the surface casing (1000 ft), with the production zone liner completed fully horizontal. While there are several methods to build angle in a deviated well (build and hold, s-shaped, and continuous), without specific conditions that may dictate one build method over another, we assume that the angle is built continuously.

Bit costs are determined using equation (1):

$$C = 3775 \times D - 21750 \quad (1)$$

where D is the bit diameter in inches and C is the bit cost in dollars. Equation (1) is applicable to a diameter range of approximately 8-1/2" to 26" and is based on bit cost data from 2010 for roller-cone, hard formation, journal bearing bits, which are the dominant type used in geothermal and O&G drilling. The total bit cost for an interval is given by C × (drilling time/bit life), which can lead to a non-integer number of bits. However, because bit life is highly variable the use of a non-integer number of bits is still statistically reasonable. Table 2 lists the default values for the balance of inputs in the WCS model that are common across all scenarios. These values are based as much as possible on an 'industry average' that provides a generic cost and performance for a well of a general type, size, and depth.

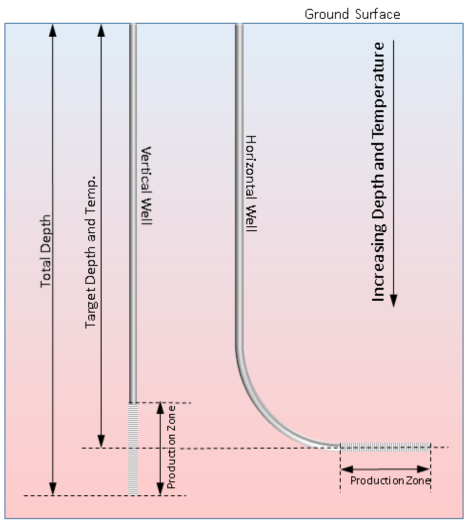

Figure 5 - Total depth versus target depth. The vertical well production zone is centered on the target depth to provide the vertical well with the same average production temperature as the horizontal well.

Figure 6 shows the cost curves for all four cases (small diameter – vertical orientation, small diameter – horizontal orientation, large diameter – vertical orientation, and large diameter – horizontal orientation). The step function change in costs for the Baseline and Intermediate 1 scenarios are due to additional intervals added to the design at the specific depths as per the GETEM criteria discussed above. The dotted lines represent a best fit to the data and are likely more representative of the actual costs since the depth at which additional intervals would be added to the design is highly dependent on the geologic and hydrogeologic conditions.

Collectively, the added cost of drilling a horizontal well versus a vertical well declines with depth from about 16% down to 12% of the vertical well cost for the small diameter wells, and 18% down to 8% for the large diameter wells. The added cost of drilling a large diameter well versus a small diameter well increases with depth from about 27% to 50% of the small diameter cost for the vertical wells, and 30% to 46% for the horizontal wells.

Table 2 - List of default values used in the WCS model that are common to all scenarios.

Input Parameter	Description	Value
BHA Cost	Bottom hole assembly	50% of bit cost
Casing Cost	K-55 casing	\$1.50 / lb
Cementing Cost	Material only	\$125.00 / ft^3
Cementing Time	Running casing	300 ft/hr
	Rigging, mixing, pumping, setting	5 hrs
Tripping	In and out of hole	1000 ft/hr
	Handling time	6 hrs
Logging	Time	300 ft/hr
	Service	\$50,000
Wellhead Time	For intervals run to surface	40 hrs
Mud Cost	Initial volume	\$10,000
	Make-up volume	\$4,000 / day
Directional Drilling	Specialized labor	\$75.00 / hr
	Motor and steering tools	\$500.00 / hr
Fixed Costs	Mobilization / de-mobilization	\$250,000 (total)
	Site preparation	\$250,000
	Pre-spud engineering	\$10,000
	Wellhead equipment	\$80,000
	Rig rental rate	\$28,500, \$33,500, \$38,400 / day 1000-2000', 2500-4500', >5000' – Large Diam. 1000-3500', 4000-4500', >5000; - Small Diam.

For EGS systems, horizontal wells have been shown to produce less thermal drawdown across a full range of fracture orientations because it eliminates density flows that can dominate vertical well orientations (Kalinina, et al. 2014; Chen and Jiang 2015). The consistency of performance for horizontal wells also reduces the uncertainty and hence the risk. Between the large and small diameter wells the main performance difference is the higher fluid friction losses in the smaller diameter holes, which for the values used here (the small diameter hole of 8.5 inches has an inside casing diameter of 6.20 inches while the large diameter hole of 12.25 inches has an inside casing diameter of 8.825 inches) results in about a 3% pressure difference at the surface. Small diameter, deep wells may have a thermal advantage over the large diameter wells since the travel time for the same mass flow rate to the surface is less, which reduces heat loss to the surrounding formation. The tradeoffs between all these factors must be considered when designing the well.

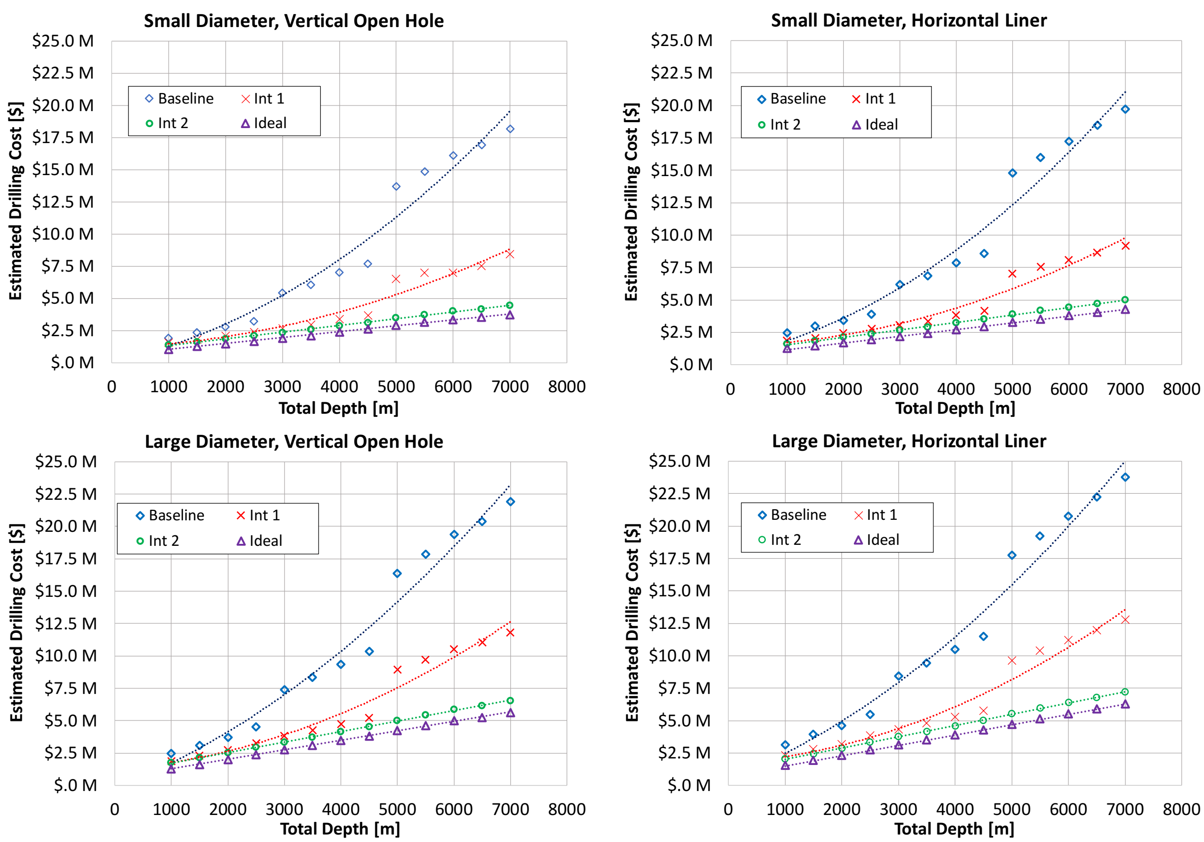

Figure 6 - The cost curves developed for the P2P Task.

3.5. Drilling Technologies

The process of drilling a well includes downhole energy transfer, rock reduction, rock removal, borehole stabilization, formation fluid control, logging, and borehole preservation. Because drilling is such a complex activity, there are numerous opportunities to reduce costs in all of these processes. Improvements can come in one of two ways: a new technology is developed that saves time and/or money or we learn how to drill more efficiently with existing technology (Blankenship, et al. 2007). The key factors and technologies that control drilling costs can be fit into three broad categories; bits, high temperature electronics, and avoiding non-drilling time, which is defined below. There are numerous documents that provide excellent descriptions of each of these areas (e.g., Tester et al. 2006; Finger and Blankenship 2010; DOE 2016) and thus are not repeated here. Rather, this section looks at the implications of drilling technology improvements to identify the key gaps and to prioritize the focus areas of future research.

Figure 7 shows the time (upper left), time cost (upper right), material cost (lower left) and total cost (lower right) percentages for different drilling cost components for the Baseline, large diameter (12.25 inch hole size) vertical well with a target depth of 5000 m (the values are listed in Table 3).

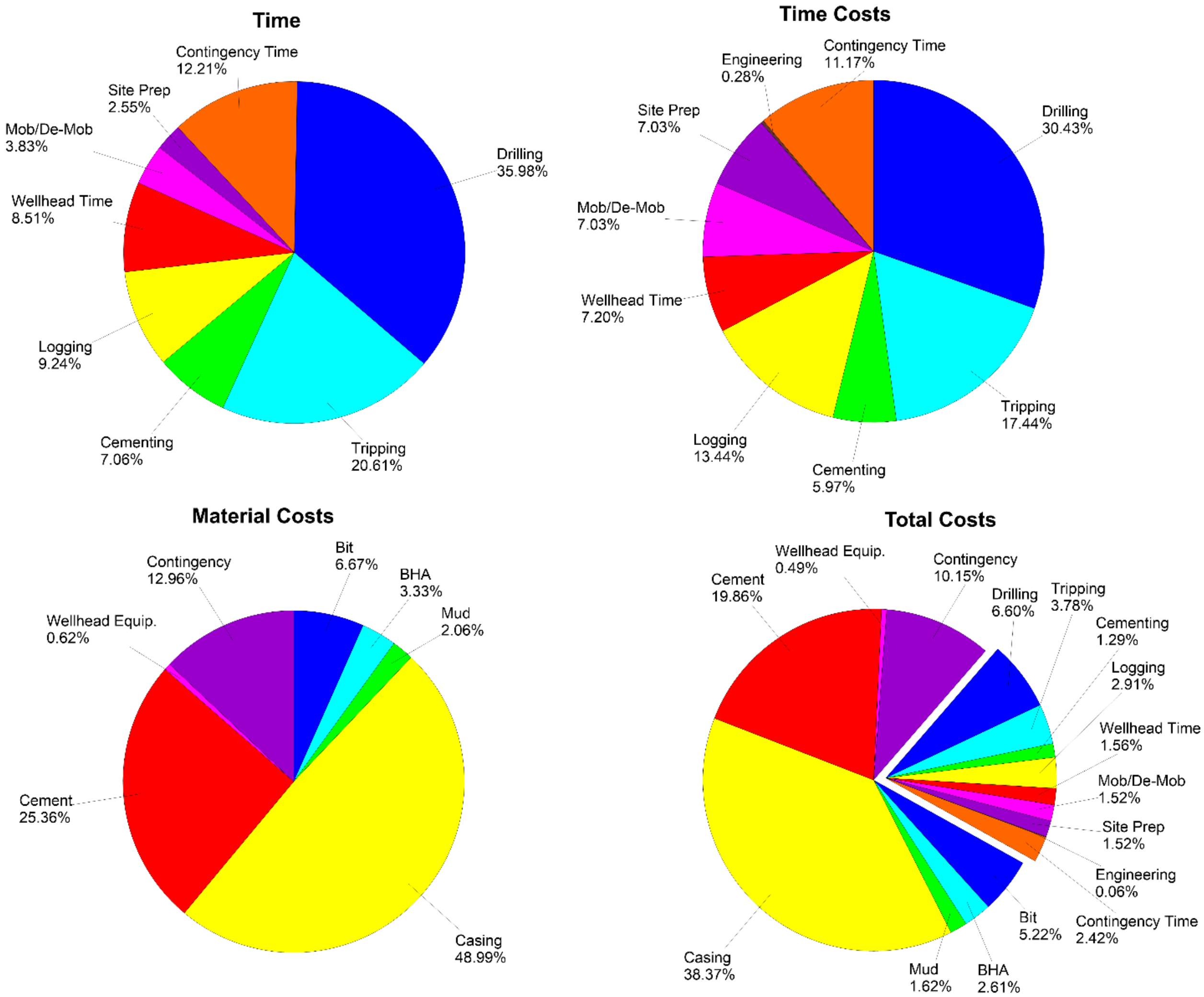

Figure 7 - Cost and time structure breakdown for the Baseline large diameter vertical well at a target depth of 5000 m. The break-out in the 'Total Costs' plot in the lower right are the time dependent costs detailed in the upper two plots. The values for these plots are listed in Table 3.

Technological improvements are also a function of depth. Figure 8 and Table 4 shows the drilling cost breakdown for the Baseline large diameter (12.25 inch hole size) vertical well at a target depth of 2500 m. For this well, the material costs are less of a factor (62.9%) and the time-dependent costs are more of a factor (37.1%) than the 5000 m target depth well. The result is that for the 2500 m target depth well, technological advances that double the ROP will be more effective from a cost reduction standpoint (14.4% cost reduction) as compared to the 5000 m target depth well (10.4% cost reduction).

Table 3 - Cost and time structure breakdown values for the Baseline large diameter vertical well at a target depth of 5000 m. These data are plotted in Figure 7.

Description	Cost	Time [hrs]	Percent Category Costs	Percent Time	Percent of Total Costs
Time Dependent Costs					
Drilling	$1,081,852	676.2	30.43%	35.98%	6.60%
Tripping	$619,932	387.5	17.44%	20.61%	3.78%
Cementing	$212,309	132.7	5.97%	7.06%	1.29%
Logging	$477,931	173.7	13.44%	9.24%	2.91%
Wellhead Time	$256,000	160.0	7.20%	8.51%	1.56%
Mob / De-Mob	$250,000	72.0	7.03%	3.83%	1.52%
Site Prep	$250,000	48.0	7.03%	2.55%	1.52%
Engineering	$10,000	0.0	0.28%	0.00%	0.06%
Contingency	$397,204	229.5	11.17%	12.21%	2.42%
SUB-TOTAL	$3,555,227	1879.5	100.00%	100.00%	21.67%
Material Costs					
Bits	$856,804	NA	6.67%	NA	5.22%
BHA	$428,402	NA	3.33%	NA	2.61%
Mud	$265,002	NA	2.06%	NA	1.62%
Casing	$6,294,161	NA	48.99%	NA	38.37%
Cement	$3,257,613	NA	25.36%	NA	19.86%
Wellhead Equip.	$80,000	NA	0.62%	NA	0.49%
Contingency	$1,665,297	NA	12.96%	NA	10.15%
SUB-TOTAL	$12,847,280	NA	100.00%	NA	78.33%
TOTAL	**$16,402,507**	**1764.5 (73.5 days)**	**NA**	**100.00%**	**100.00%**

Table 4 - Cost and time structure breakdown values for the Baseline large diameter vertical well at a target depth of 2500 m. These data are plotted in Figure 8.

Description	Cost	Time [hrs]	Percent Category Costs	Percent Time	Percent of Total Costs
Time Dependent Costs					
Drilling	$485,862	348.1	28.95%	39.89%	10.75%
Tripping	$176,738	126.6	10.53%	14.51%	3.91%
Cementing	$59,532	42.6	3.55%	4.71%	1.32%
Logging	$181,908	58.7	10.84%	6.72%	4.03%
Wellhead Time	$111,667	80.0	6.65%	9.17%	2.47%
Mob / De-Mob	$250,000	3.0	14.90%	8.25%	5.53%
Site Prep	$250,000	2.0	14.90%	5.50%	5.53%
Engineering	$10,000	0.0	0.60%	0.00%	0.22%
Contingency	$152,356	98.4	9.08%	11.25%	3.37%
SUB-TOTAL	$1,678,062	759.4	100.00%	100.00%	37.14%
Material Costs					
Bits	$308,181	NA	10.85%	NA	6.82%
BHA	$154,090	NA	5.42%	NA	3.41%
Mud	$119,338	NA	4.20%	NA	2.64%
Casing	$1,052,261	NA	37.04%	NA	23.29%
Cement	$766,726	NA	26.99%	NA	16.97%
Wellhead Equip.	$80,000	NA	2.82%	NA	1.77%
Contingency	$360,089	NA	12.68%	NA	7.97%
SUB-TOTAL	$2,840,686	NA	100.00%	NA	62.86%
TOTAL	**$4,518,748**	**759.4 (31.6 days)**	**NA**	**100.00%**	**100.00%**

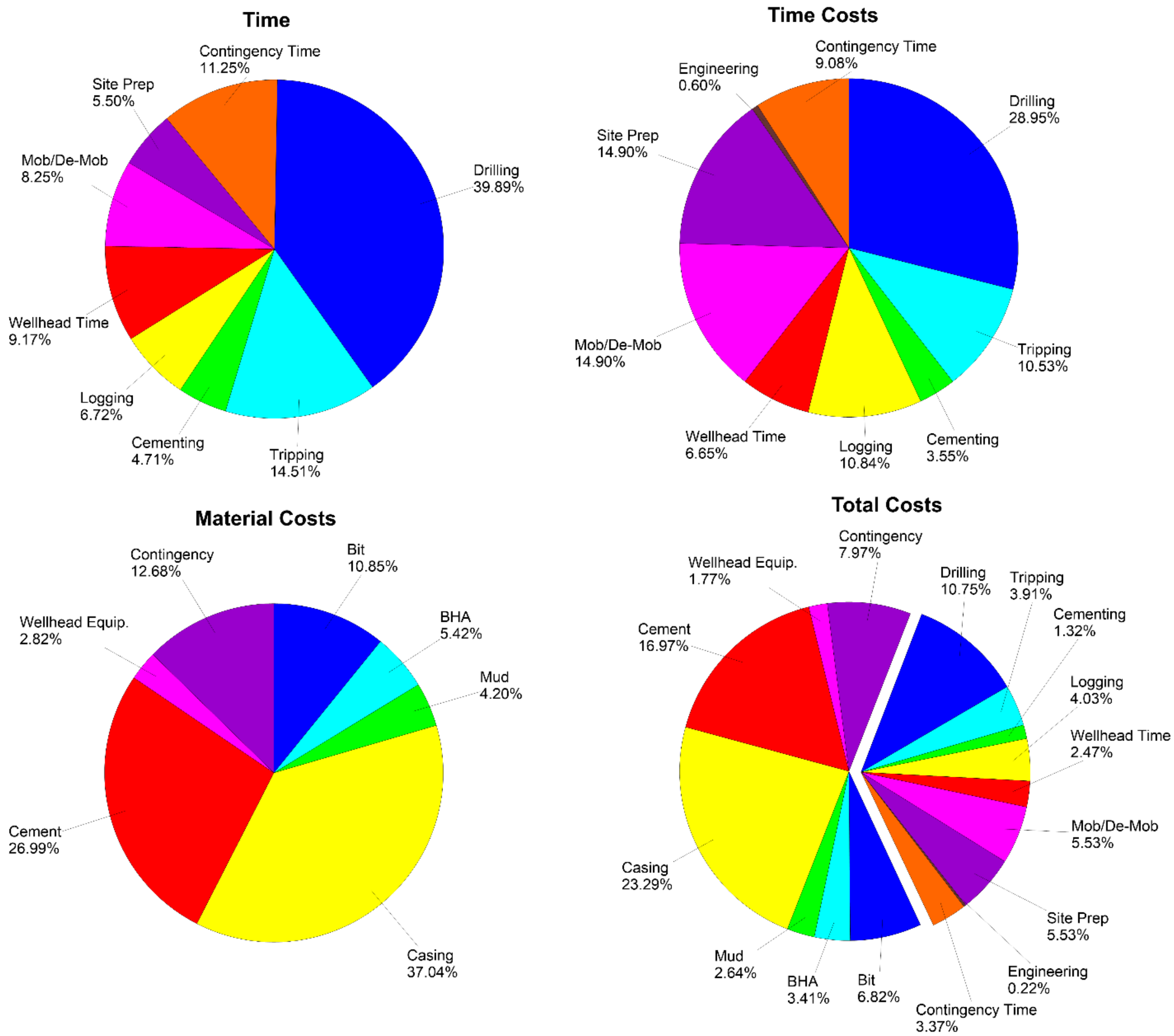

Figure 8 - Cost and time structure breakdown for the Baseline large diameter vertical well at a target depth of 2500 m. The break-out in the 'Total Costs' plot in the lower right are the time dependent costs detailed in the upper two plots. The values for these plots are listed in Table 4.

From the 'Total Costs' plots (lower right) in Figure 7 and Figure 8, it is apparent that the costs attributed to time-dependent activities are a relatively small part (21.67% and 37.14% for the 5000 m and 2500 m wells, respectively) of the total drilling costs. However, there are dependencies amongst the cost factors that must be accounted for when estimating technological advancements. For instance, doubling the ROP while leaving everything else constant has a larger impact than just cutting the drilling time costs in half. It also reduces the number of trips and thus the total tripping time, the bit and BHA costs, and the contingency costs since a fewer number of bits will be used and contingency is based on a percentage of total drilling activity costs. Figure 9 illustrates this by showing the relative cost of each component at ROP's of 25 and 50 ft/hr. The reduction in the bit and BHA, drilling time, and tripping time costs can be seen. Because the total cost goes down at the higher ROP, we see increases in the percent cost attributable to wellhead equipment, wellhead time, and casing and cement costs.

There are two important lessons from this example; 1) the relative impact of a new technology is dependent on the well specification and 2) there is no single technology that can significantly reduce

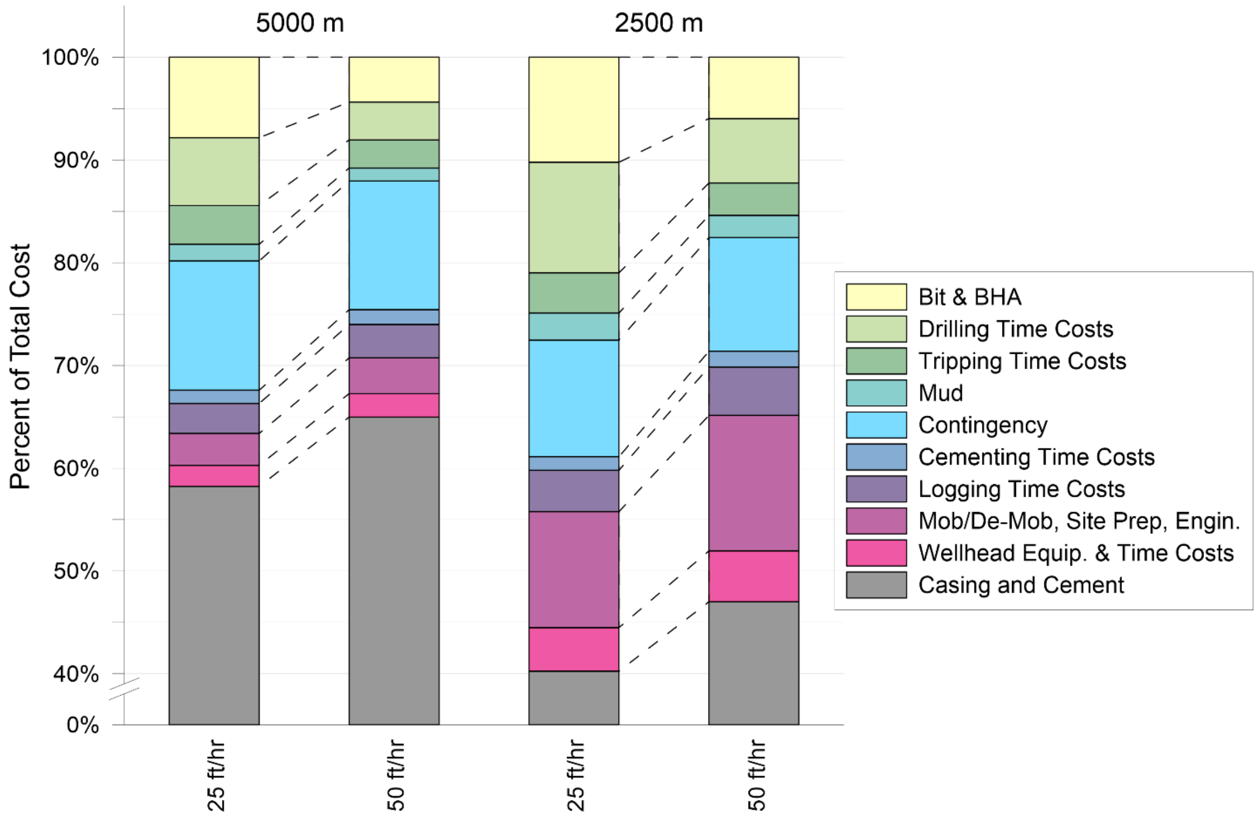

Figure 9 - Relative costs of the drilling components showing the effect of doubling the ROP for the Baseline large diameter vertical well at target depths of 5000 m and 2500 m. As a percentage of the total cost, time costs tend to decline as ROP is increased while material costs, with the exception of bit and BHA costs, tend to increase.

costs by itself. This means that drilling research efforts must have multiple but coordinated focus areas that cover the full range of drilling activities.

The literature contains many definitions and descriptions of drilling research focus areas, which for the purposes of this report are generalized into the following categories:

- Bit Design
- High Temperature Environments
- Non-Drilling Time

3.6. Bit Design

Drill bits come in two general configurations; roller-cone bits that crushes the rock as it turns under-pressure on the bottom of the hole, and drag bits, which shear the rock in a similar way that machine tools cut metal. In most applications, drag bits are more efficient than roller-cone bits (Finger and Blankenship 2010).

Roller-cone bits have been around for over 100 years and are a very mature technology. They currently dominate geothermal drilling because of their durability in hard, fractured rocks and the fact that they are less expensive than drag bits (Finger and Blankenship 2010; Blankenship 2016). However, roller-cone bits contain either roller or journal bearings that require lubricants and seals that are vulnerable to the high temperatures found in geothermal environments.

Drag bits are not susceptible to high temperatures due to the fact that they contain no moving parts. Current drag bit technology uses PDC cutters, which have been widely adopted by the O&G industry due to their higher ROP and longer bit life over roller-cone bits (Polsky et al. 2008; DOE 2016). Sandia National Laboratories has been involved with the development of PDC bits for the past three decades and has pioneered their use in hard-rock environments (Finger and Glowka 1989). It has been estimated that two-thirds of the worlds O&G footage has been drilled with PDC bits (Blankenship 2016). However, the adoption of PDC bits in geothermal drilling has been relatively slow as compared to the O&G industry for three main reasons; 1) cutter wear in hard-rock environments, 2) vibration due to cutter failure, and 3) absence of service industry (Polsky et al. 2008; Raymond et al. 2012).

Polsky et al. (2008), states that the first two reasons can be attributed to three fundamental lithological characteristics: rock abrasiveness, rock hardness, and heterogeneity. As the O&G industry begins drilling more hard rock environments, improvements in PDC bit design have been made. Changes in cutter design and more experience in using PDC bits in hard rock environments has reached the point where PDC bits are beginning to outperform roller-cone bits for geothermal applications.

Raymond et al. (2012) demonstrate PDC bit advancements by testing them in the granite formations of the Chocolate Mountains in Southern California. Their experiment compared two PDC bit designs, one equipped with torque control components (TCC) and one without, against a roller-cone bit. TCC limits the ROP by design to keep bit torque below a specified threshold. All three bits are commercially available. In terms of the ROP, the two PDC bits outperformed the roller-cone bit by over 2:1 (23.42 ft/hr [7.14 m/hr] average for the PDC bits, 10.7 ft/hr [3.26 m/hr] for the roller-cone bit).

More importantly, the Raymond et al. (2012) study estimates the costs associated with drilling a standardized interval with each of the bits. They set the cost of a PDC bit \$4 per foot with a \$14,500 minimum (PDC bits are leased, not purchased) and the cost of the roller-cone bit at \$3,200. Despite the higher cost of the PDC bits the estimated cost per foot for the TCC and non-TCC PDC bits was \$45 and \$59 (\$148 and \$194 per meter), respectively, while the roller-cone bit averaged about \$74 per foot (\$243 per meter). The savings of using PDC bits is attributed to their higher ROP and extended bit life (>1000 m for PDC versus 300-400 m for roller-cone).

As a comparison, Baujard, et al. (2017) analyzed drilling data from four sites in the Rhine Graben and five wells in the Bohemian granite and gneiss in Austria to estimate ROP. While they do not consider the bit type, their results show that most of the ROP values ranged from about 2 – 7 m/hr (6.5 – 23 ft/hr) and that the ROP decreases with depth. For wells drilled between 2000 and 3500 m, the ROP ranged from 3 – 7 m/hr (10 – 23 ft/hr) but for wells greater than 3500 m, the ROP varied between 2 and 4 m/hr (6.5 – 13 ft/hr). Noticeable peaks to between 15 and 20 m/hr (50 – 65 ft/hr) occurred in narrow zones where the granite was fractured or altered.

Beyond the traditional drag and roller-cone bit technology, there are other technologies that show promise but are not currently deployable. The focus has been on technologies that aim to alter the rock ahead of the bit to make it easier to drill and include chemical enhanced drilling (CED), jet-assisted drilling (JAD), and laser enhanced drilling (LED). In one form or another, CED and JAD have been around since at least the early 70's while LED is a more recent technology (Song, et al. 2017).

CED uses additives to the drilling fluid to alter the rock to make it more susceptible to reduction. However, despite its conceptual simplicity, CED suffers from several limitations, the most prominent of which are the rate that a chemical can react with the rock, the toxicity and disposal of some of the added chemicals, and the cost (Zhang, et al. 2016).

JAD uses the mechanical force of high-pressure fluid jetting in front of the bit to 'erase' the tension in the rock to make it easier to drill. The main limitation of JAD is the reliability of the downhole super-charger that is used to create the pressure, and the integration of the jets with the drill bit (Zhang et al. 2016). Compared to CED and LED, JAD is considered to be the closest to market (Baujard et al. 2017), with testing of state-of-the-art JAD technology on 60 oil wells in China showing an increase in ROP of 11-831% (Zhang et al. 2016). As an indication of JAD's promise, the European Union's Horizon 2020 research and innovation program is currently funding the ThermoDrill Project to advance JAD technologies with a goal of increasing the ROP by 100% and reducing drilling costs by 30% for drilling in hard rock, geothermal environments (Eisner 2016; ThermoDrill 2017).

LED (sometimes referred to as laser assisted drilling) uses lasers to break the rocks through thermal spallation or by melting and vaporization. LED is commonly used for drilling stones, rock, and marble but has yet to be field tested in deep, hard-rock environments (Khan, et al. 2015). The use of lasers for drilling was first investigated in 1998 using laser technology from the U.S. StarWars defense program (O'Brien, et al. 1999; Graves and Batarseh 2002). That program, which was implemented through the Colorado School of Mines, showed that lasers can destroy rock without damaging formation permeability and that it can be done with less specific energy than had been previously estimated. Khan et al. (2015) state that LED is the "ultimate holy-grail" for drilling through hard rock. With regards to improvements to the ROP, Ezzedine, et al. (2015) use a combination of laboratory experimentation and numerical modeling to estimate that the ROP could be increased by a factor of three using LED technology. Despite the promise of LED, it is currently limited by our ability to deliver the laser energy down the borehole in a reliable manner.

3.7. High-Temperature Environment

It has been stated that for efficient and economically viable power production, geothermal production temperatures should be greater than 200 °C (Tester et al. 2006) and thus downhole equipment and materials for geothermal drilling and production must be able to withstand extended periods at and above that temperature without a degradation in performance and/or reliability. Coupled with these high temperatures are high pressures, vibration and shocks, and harsh chemical environments that only add to the unforgiving geothermal environment.

The main failure points within downhole components are the electronics and elastomers and organic materials. Due to the integrated nature of these systems, the issue must be approached as a whole-systems problem because there is not a single system solution that can create a sudden step change in capability (Norman 2006; Sisler, et al. 2015; Watson and Castro 2015). The downhole components that are vulnerable to these failures control power storage, regulation, and conversion, motor drives, data acquisition, data storage, monitoring, and pumps. The high temperature environment also accelerates other failure modes such as intermetallic growth and voiding, materials outgassing, corrosion, hydrogen darkening of optical fiber, and stress induced failures, all of which can impact long-term borehole integrity as well as the downhole components (Blankenship 2016).

Work in high temperature electronics has been ongoing for decades but even with the progress over that time there are relatively few commercial-off-the-shelf (COTS) products that are rated for use above 175 °C, although this situation is starting to improve as high temperature electronics become more important in other industries such as the avionics, aerospace, and automotive industries (Sisler et al. 2015; Watson and Castro 2015).

In 2015, Baker Hughes completed a project for the DOE Geothermal Technologies Office (GTO) to develop a prototype directional drilling system that includes the bit, directional motor, and drilling fluid that provides at least a 50-hour lifespan in a 300 °C, 10,000 m deep environment (Chatterjee, et al. 2015). The intent was to design the system such that each piece worked cooperatively to produce the desired performance. Several prototypes and configurations were tested at the Baker Hughes Experimental Test Area (BETA) in Oklahoma, a site in Celle, Germany, and in a high-temperature test stand. The report states that they were successful in developing "three prototype drilling systems capable of drilling directional wells at 300 °C", although more field testing is needed to establish durability and lifespans. As of this writing, the current status of these developments is not clear.

Two areas of prime importance for the geothermal industry are in logging and monitoring (Blankenship 2016; DOE 2016). Standard open hole logging tools are used to measure things such as temperature, pressure, flow (spinner), spontaneous potential, resistivity, total gamma, gamma density, neutron porosity, nuclear magnetic resonance (NMR), micro-resistivity, and ultrasonic borehole imaging. Standard logging is typically done as wireline meaning that the logging tools are lowered into the borehole once drilling is complete. Most open-hole logging tools are available in high-temperature versions up to 260 °C, making them suitable for the majority of geothermal applications (Blankenship 2016). However, some of these high-temperature logging tools are limited by their minimum hole diameter that precludes their use in 8.5" casing. As a special application, none of these tools are suitable for super-critical environments.

Another approach, logging while drilling (LWD), logs the system during the drilling process with sensors that are integrated into the drill string. Usually, information is transmitted back to the surface via electromagnetic waves or pressure pulses through the drilling fluid. This method of data transmission is limited in band width and thus LWD systems must record high-resolution data into memory that can be retrieved later when the drill-string is withdrawn. More recent advancements involve networked or wired drilled pipe, which can transmit high density data in real-time. Unfortunately, flash memory for storing the data to retrieve later as well as networked pipe are not yet suitable for high temperature environments, although Halliburton states they have a 230 °C system with directional, drill string dynamics, pressure and gamma information (Blankenship 2016). Work on developing these capabilities is ongoing with promising results to date (e.g., Cashion 2015; Sisler et al. 2015; Watson and Castro 2015).

Similar to LWD tools are measurement while drilling (MWD) tools. The difference with LWD is that MWD tools collect real-time data on temperature, pressure, shock and vibration, direction and inclination, rotational speed, weight on bit (WOB), and torque on bit while LWD tools collect open-hole logging measurements. MWD tools and the data linkages to the surface are required for directional drilling (DOE 2016), but high temperatures are a challenge for both the instrumentation and the elastomers of the downhole motor. The issues of high temperature instrumentation for MWD are the same as those for other logging tools and can be addressed with the same technological advancements. Research in high temperature elastomers and novel downhole motor designs is helping to clear this hurdle (Redline, et al. 2015; SNL 2016).

A variant of logging and monitoring is drill-stem testing, which isolates and tests the pressure, permeability, and productive capacity of a geological formation during well drilling. It is primarily used in O&G to help determine when a well has reached a commercially viable hydrocarbon source. Applied to geothermal, it can be used for EGS applications to find areas of suitable permeability for stimulation and in hydrothermal applications to find areas of adequate flow. Like logging and monitoring, the electronics required to perform drill-stem testing must be able to perform in high-temperature conditions. Current technology includes Schlumberger's 'Quartet HT' downhole reservoir testing system that is rated to 210 °C (Schlumberger 2017), so this gap is closing.

As is discussed in detail below, LWD and MWD tools are key technologies for reducing drilling costs by providing the drilling crew with real-time information that allows them to drill more efficiently and avoid trouble. LWD and MWD tools are perfect examples of the technological dependencies that manifest in geothermal drilling processes and a reason that research activities need to be integrated and coordinated.

The use of insulated drill-pipe (IDP) has been shown to keep the temperature around motors and electronics much cooler than with conventional drill pipe (CDP) (Finger, et al. 2002). The concept of IDP is to deliver drilling fluid to the bottom of the hole at a much cooler temperature than is otherwise possible. Finger et al. (2002) describes the theoretical background of IDP and provides results from laboratory and field testing. Their results show that for a 3050 m deep well with a terminal temperature of 350 °C, the bottom-hole fluid temperature was reduced from 205 °C with CDP to 75 °C with IDP. The results also show that the mud return temperature is higher with IDP (91 °C vs 73 °C), which may require the use of mud coolers. The higher return temperature also indicates that more heat is being removed from the borehole, which can have benefits for logging and cementing after drilling. Despite the promise of these results, IDP has not been readily adopted by the geothermal or O&G industries most likely due to the added cost of IDP versus CDP. An economic tradeoff analysis is needed to explore this issue further.

It is worth noting that active cooling technologies can be used to keep the relevant components below the ambient temperature. Active cooling involves the circulation of cooling fluids through the borehole (e.g., mud coolers) (Blankenship et al. 2007). Pennewitz, et al. (2012) show the importance of insulating downhole components and the effectiveness of phase-change insulators. Using a liquid to gas phase change insulator, they show that a component starting at 25 °C can stay below 200 °C for up to 20 hours when exposed to a 250 °C environment. As an example of the effectiveness of active cooling Saito and Sakuma (2000) looked at how top drive drilling system cooling impacts the ROP, bit life, and economics of drilling. Their study examined two wells in the Kakkondo geothermal field north of Tokyo, Japan and showed that cooling increased bit life three to six times over conventional drilling, mainly due to better longevity of the O-ring seals.

With regards to the GeoVision Study, the development of tools and materials that can withstand the high temperature geothermal environment is imperative if geothermal energy is going to ever reach its potential. Failure of something as simple as an O-ring can force the shutdown of drilling to trip out of the hole to diagnose and fix the problem. This is both time consuming and expensive. Functional high temperature electronics for MWD and LWD tools also allows drillers to avoid trouble time by conveying in real-time when conditions may be leading to lost-circulation or other troubles.

3.8. Non-Drilling Time

Non-drilling time (NDT) is time spent over the drill rig without deepening the hole and encompasses 'flat time', 'non-productive time', and 'trouble time'. Flat time is typically defined as the time spent on required activities that do not advance the hole, such as running casing, cementing, etc. Non-productive time usually refers to unplanned time associated with the operation of the rig, such as equipment breakdown, ill-fitting parts, etc. Trouble time is usually thought of as time associated with correcting issues within the borehole. Since there is overlap in these terms and different companies and industries define these terms slightly different, we are defining NDT to include any time or activity that is spent in not deepening the hole under the premise that there is considerable potential time and cost savings that can come from reducing NDT, regardless of its source.

NDT is most commonly caused by lost circulation and stuck pipes (Moazzeni, et al. 2012; Cole, et al. 2017) but also includes other problems such as difficulty cementing, wellbore instability, and equipment failures (Finger and Blankenship 2010). Lost circulation, is caused when the drilling fluid flows into the geologic formation instead of returning to the surface and is estimated to cost the O&G drilling industry a $1 billion per year in rig time, materials, and other financial resources (Ferron, et al. 2014) and adds an estimated average of $185,000 per well to geothermal rig costs (Cole et al. 2017).

Because geothermal drilling environments tend to be under pressurized with multiple zones of highly fractured and altered material, lost circulation is more common in geothermal drilling than in other applications (Finger and Blankenship 2010). The time and material costs for lost circulation can represent 10% of the total well costs in a mature geothermal field, and often exceeds 20% of the costs for exploratory wells and reservoir development (Finger and Blankenship 2010; Almagro, et al. 2014). In many cases, geothermal wells have been abandoned due to lost circulation (Mansure 2002), which can quickly put a geothermal project into economic difficulty. For those reasons, lost circulation deserves special attention as a means of reducing NDT.

The implications of lost circulation are many and can sometimes lead to a cascade of events from which recovery is difficult. If the drilling fluid is unable to clean the hole, cuttings can fall back on the bottom-hole assembly and stick the drilling assemble. If lost circulation suddenly lowers the fluid level in the well, hot water, steam, and/or gas can enter the wellbore causing a loss of well control. Furthermore, if circulation is lost in the production zone, it may be difficult to cure or manage the lost circulation without compromising the well's productivity. In addition, lost circulation can result in bad cement jobs that can lead to further issues down the road.

There are several approaches available for mitigating lost circulation. In the general order from the least time consuming and expensive to the most they are (there are exceptions that can change this order): 1) drill ahead with lost circulation, 2) drill with a light weight drilling fluid to reduce the static head in the borehole below the pore pressure in the formation, 3) add fibrous material or particles to the drilling fluid to plug the lost circulation zone, and 4) seal the loss zones with material that can be drilled out later (Garcia, et al. 2005; Finger and Blankenship 2010).

Advancements over the last few decades for mitigating lost circulation has focused on newer lost circulation materials (LCM's) to plug and/or strengthen the formation (#3 above). Historically, LCM's were chosen because they were readily available and inexpensive and have included cottonseed hulls, shredded leather, sawdust, straw, and ground walnut shells (Almagro et al. 2014). Since then, LCM's have advanced considerably and are now fully engineered materials with specific applications based on formation type, fracture size, cause of lost circulation, etc. Research in the optimization of the use of LCM's is ongoing and is increasing our ability to recover from lost circulation events more quickly and/or recover from events that were unrecoverable a few decades ago (e.g., Ferron et al. 2014; Yili, et al. 2015; Razavi, et al. 2016; Xu, et al. 2016; Alsaba, et al. 2017).

Despite the progress in mitigating NDT, by far the most effect cost reduction technique is to prevent NDT from happening in the first place. There are three primary pathways for achieving this: 1) Drilling well on paper (DWOP), 2) MWD and LWD, and 3) Experience.

DWOP is a common practice within the O&G industry and involves analyzing the steps of well construction to identify areas for improvement and reducing cost. The approach usually involves a panel of SME's who share their experience across numerous specialties. With regards to lost circulation and reducing trouble time, the DWOP process can be scaled back to focus on the mechanical and operational aspects of well control such as casing design, mud densities, equipment ratings, and other operational procedures. Geomechanical models of the drilling process are used to help identify zones of potential loss so that engineers can select drilling fluids with rheological properties that reduce the risk of lost circulation (Almagro et al. 2014; Ferron et al. 2014; Mehrabian, et al. 2015). This also allows drillers to have materials on site that can mitigate the predicted worst case scenario. Preventive measures to avoid lost circulation can involve adding wellbore strengthening materials such as ground marble (calcium carbonate) or synthetic, deformable graphite to the drilling fluid, or in extreme cases, setting casing across the lost circulation zone, although this is expensive compared to other alternatives.

An example of the DWOP concept can be found in Unocal's geothermal division 1999 project in Awibengkok, West Java, where they were able to drill wells much faster and cheaper than other operators in the area who were using the same general technology and tools as Unocal (Melosh 2017). Unocal saw their drilling time per well drop from 53 days to 20 days over a 15-year period. Melosh (2017) attributes part of these improvements to Unocal's team decision process that forecast possible impacts of decisions and designs by critically looking at detailed data and opinions from SME's in advance. In the business community, this is sometimes referred to as agility; being open to 'outside eyes' in a continuous attempt to improve efficiencies and reduce costs. The Unocal operation and the DWOP process in general, are both examples of the concept of agility being applied to drilling operations with demonstrable success. While the O&G industry appears to be open to this, it is currently not as common in geothermal (Melosh 2017).

As discussed above, MWD typically measures concerns associated with the borehole while LWD measures aspects of the geologic formation. When available in real-time, both of these measurements provide data that can be useful to the driller to avoid and prevent lost circulation and other potential problems and increase drilling efficiencies. Besides the current limit of MWD and LWD tools to temperatures at or below 200 ^{o}C, there is also a limit on the data transfer rate to the surface (it should be noted that the 200 ^{o}C limitation is a rough estimate and refers to the temperature of the downhole component as opposed to the formation temperature). Currently, the majority of MWD and LWD tools use mud pulse telemetry (MPT), which uses wave propagation through the mud column, to transmit data to the surface (Shao, et al. 2017). While highly reliable and relatively accurate, data rates are slow. Typical data transfer rates in the field are around 10 bits per second (bps) although some commercial products are claiming rates up to 40 bps (Finger and Blankenship 2010; Berro and Reich 2015; MWD 2017; Shao et al. 2017). As an example, modems in the 1970's that were used for sending and receiving digital faxes could transfer data at up to 14,400 bps. The limited data rates of MPT also requires that complex data processing be carried out in the downhole tool, which places a premium on the development of high temperature electronics.

For MWD and LWD to be truly useful in reducing NDT, better real-time data collection, transmission, and interpretation is needed, of which the principal barrier is the lack of transmission speed (Finger and Blankenship 2010). A technology that can meet this need is wired drill pipe (WDP), which can transmit data at a rate of 1 million bps (1 Mbps). The invention of the WDP technology, known as IntelliServ, was developed by industry in 2006 with funding from the Department of Energy's National Energy Technology Laboratory (NETL).

As of 2013, WDP had been deployed in O&G applications in more than 110 wells worldwide, showing an ability to reduce overall drilling costs through better well control and drilling management (Pixton 2013). Field results show that the real-time feedback of the downhole formation and borehole conditions allowed drillers to achieve ROP's that were 2-4 times greater and reduce NDT by 50-75% over wells in the same formation without WDP (Veeningen, et al. 2012; Pixton 2013). This in turn, reduced total drilling costs by up to 10%. The holy grail of this technology is the development of automated drilling coupled with machine learning algorithms whereby the entire drilling process is continually adjusted in real-time to optimize every aspect of the process. While the promise is there and the technology seems ready for rapid acceptance in the O&G industry, it lacks the durability and robustness for use in geothermal environments.

Beyond technological barriers, another major factor in geothermal drilling costs is a lack of long-term experience. Most discussions on geothermal drilling highlight its differences with O&G but there are those who believe that those differences are small when compared to their common characteristics (Janecke 2012) and that the geothermal industry should better leverage the decades of experience in O&G. The experience gap in geothermal drilling makes it more difficult to establish and use standardized approaches and limits the availability of specialized equipment (e.g., high temperature electronics), both of which reduce NDT and costs. The WDP technology is a case in point to this fact.

The International Finance Corporations' study (IFC 2013) of geothermal well success and a companion study using most of the same data (Sanyal and Morrow 2012) provides some foundation to the 'learning curve effect' in geothermal drilling. The IFC (2013) study gathered geothermal drilling data for 2,613 wells (2,528 for (Sanyal and Morrow)) from 57 fields in 14 countries, representing about 71 percent of the global installed geothermal power capacity. Overall, for the wells for which their status could be confirmed, 78 percent of the wells were deemed 'successful'. In both studies, success was defined as any production well with an ending power-generating capacity of 3 MWe or more.

The IFC (2013) study states that there is a strong learning curve effect. On average, the success rate for the first well in a field is 50% while the average success rate for the first five wells is 59%. The success rate rises to 74% during the development phase and to 83% for wells drilled during the operational stage. The IFC (2013) study also shows that the geology of the field has an effect on the success of a well, with fields in sedimentary basins having higher success rates than other environments. This may or may not be attributable to the preponderance of experience in the O&G industry in drilling in sedimentary systems.

The Sanyal and Morrow (2012) study looked more closely at the learning curve effect by using the average MW capacity per well as compared to the total number of wells drilled on a field by field basis. For the large steam dominated fields, (Kamojang in Indonesia, and The Geysers in California), there was almost no change in the average capacity between wells drilled early in the fields existence and later (The Geysers showed a slight reduction due to reservoir pressure depletion). For the 19 liquid dominated fields that were analyzed, their analysis showed unpredictable step changes in well capacity, which they attribute to changes in the conceptual model of the field that affects well siting and/or design. Sanyal and Morrow (2012) also compare the drilling success rate in the exploration phase (defined as the first five wells) to those beyond, showing that during the exploration phase, the success rate varies wildly and then stabilizes after about 40 wells are drilled. The success rate data for the 52 fields they analyzed is normally distributed with a mean of about 68%. They conclude that there appears to be no continuous learning curve effect with respect to increases in average well production or drilling success but also state that if there is a continuous learning effect, it could be masked by the statistically small sample sizes.

Wall and Dobson (2016), as part of their work on the Exploration Task of this GeoVision Study, point out the limitations of the definition of success as used in the Sanyal and Morrow (2012) and IFC (2013) studies, implying that the learning curve effect is dependent on the metric by which success is defined. This is supported by Sanyal and Morrow (2012), who end their study showing that there is a learning effect with regards to the ROP, showing that ROP approximately doubles from the exploration to the operational stage at the Kamojang Field (they did not report changes in ROP for other fields). Since the goal is to reduce the cost of drilling, we suggest that the definition of success reflect the average drilling cost in dollars per foot per MW. Unfortunately, cost data for geothermal wells are usually proprietary and difficult to come by (Lukawski et al. 2014) and thus a metric based on dollars per foot is not currently possible in a way that would be statistically valid. This will hopefully change as more geothermal wells are drilled and more data on drilling costs are gathered.

Estimates of the potential improvements associated with the learning curve effect can be found in the O&G literature. Lukawski et al. (2014) use the cost ratio of development wells to the first exploration well in an oil or gas field using JAS data from 1989 to 2009 and show that on average, development wells are 8% less expensive than exploratory wells and can be up to 18% less expensive in deep wells (2000-5000 m). They state that these estimates are likely to be conservative since they do not account for differences in drilling technology between exploratory and development wells nor do they account for the fact that most exploratory wells are vertical while many development wells are horizontal.

Lukawski et al. (2014) extend their analysis to geothermal wells by utilizing the power-law drilling performance estimate reported by Brett and Millheim (1986) and converting them to well costs by adjusting the time-dependent costs components of geothermal wells. Their results show that the fifth and tenth well of a geothermal development project should cost no more than 80% and 75% of the first well, respectively (20% - 25% reduction). This clearly indicates the possibility of a learning curve affect but more data are needed to be able to quantify it with certainty. Nevertheless, this points to the importance of geothermal development companies maintaining consistency over time with regards to drill rig experience.

The lack of publically available geothermal drilling data is hurting the advancement of the industry by slowing the learning curve and preventing the deployment of targeted research efforts that can provide the greatest benefit. This issue has been identified as a problem in the European geothermal community where a call for developing a European drilling project database has been made (Dumas, et al. 2013). Through its National Laboratory system, which has extensive infrastructure in place for the protection of proprietary and classified data, the DOE could provide a similar platform in the US where operators can share this information with the incentive that the collective information is provided anonymously to industrial and research communities with the incentive of accelerating the learning curve and technology development to lower overall drilling costs. Considering the relatively small size of the geothermal community, the benefits of this type of collaborative thinking could be significant.

3.9. Stimulation

Stimulation is used to enhance the natural permeability of a reservoir to a point where fluid flow and heat extraction can be achieved in an economical manner. While stimulation is used in the maintenance and management of hydrothermal systems to rejuvenate underperforming systems or extend them to increase overall capacity (DOE 2016), this section focuses on stimulation and its use in developing EGS systems, due to the importance of stimulation on the future of EGS.

It can be argued that the two most important obstacles to the economic success of EGS are our inability to achieve adequate flow due to lower than expected permeability after stimulation, and thermal short-circuiting (EGSRMO 2007; Jung 2013; McClure and Horne 2014; DOE 2016). An optimal EGS reservoir should have a large network of flow paths that is complex enough to sample a large volume of rock, permeable enough to allow the circulation of economically exploitable amounts of fluid and heat, and uniform enough to avoid preferential pathways that can lead to short-circuiting. To date, this has not been achieved, although a path forward for achieving this is becoming clearer as time goes on (Kalinina, et al. 2012; McClure and Horne 2014). It is worth noting that the upcoming Phase 3 portion of the DOE

Frontier Observatory for Research in Geothermal Energy (FORGE) program will develop an underground laboratory to conduct cutting-edge EGS research to address these issues.

There have been approximately three dozen field-scale stimulations and stimulation experiments in the geothermal industry as compared to the millions of stimulations conducted in O&G (DOE 2016). While there are important lessons to learn from the O&G experience, there are important distinctions that make the direct transfer of O&G stimulation technology to geothermal challenging: 1) an EGS well is usually completed with long open intervals of tens to hundreds of meters, 2) the ability to use isolation packers is very limited, and 3) a large volume of fluid is injected with the expectation of forming a permeable fracture network (Xie and Min 2016). Outside of that, the same issues that plague geothermal drilling such high temperatures and pressures also effect stimulation.

3.10. Stimulation Methods

The most common method for permeability enhancement in geothermal reservoirs is hydraulic stimulation. While it can be argued that thermal stimulation is a separate stimulation technique, thermal effects play a major role in hydraulic stimulations' design and success and thus for this discussion, thermal stimulation is considered a subset of the larger hydraulic stimulation category (DOE 2016). Hydraulic stimulation can be applied in one of two modes depending on the project or operational objectives; 1) hydraulic fracturing, and 2) hydraulic shearing (Xie et al. 2015; DOE 2016). Hydraulic fracturing (HF) is commonly applied in the O&G industry to create new fractures for the purpose of increasing access to a higher volume of rock as opposed to altering the formation permeability between two wells. Hydraulic shearing (HS) on the other hand is used to activate shear in existing fractures with the purpose of enhancing reservoir permeability. HF is accomplished using injected fluid pressures that are higher than the minimum in-situ stress to create new fractures by overcoming the tensile forces of the rock. The goal of HS is to increase the pore pressure in existing fractures such that the existing in situ stresses create shear failure along existing fractures. HS uses injections pressures that are somewhat below the minimum in situ stress (Gandossi and Von Estorff 2015; DOE 2016).

Other stimulation methods include thermal, chemical, and dynamic loading (Gandossi and Von Estorff 2015). Thermal stimulation (TS) uses the injection of relatively cool water to initiate fracturing or shearing through several thermodynamic mechanisms: mismatched expansion of minerals, anisotropic thermal expansion of minerals, heterogeneous temperature gradients, and thermo-chemical reactions (Siratovich, et al. 2015). TS is a large and sometimes dominant component in HS (DOE 2016) and can occur during drilling or during the normal operational injection process as a function of the temperature difference between the reservoir and the injected fluid (Grant, et al. 2013). Chemical stimulation involves the use of biological and/or chemical agents that causes fracturing or shearing by changing the in situ stresses through gas production, heat production, and/or mineral dissolution.

Dynamic loading involves the use of an explosive or propellant to create fracturing and shearing (Grubelich and Thoma 2012; Gandossi and Von Estorff 2015). The number and extent of fractures produced by dynamic loading is a function of the loading rate, which is the ratio of the maximum pressure to the rise time to maximum pressure (Panchadhara, et al. 2017). Generally, low loading rates produce fewer but longer fractures and high loading rates produce numerous fractures localized around the borehole. Explosive detonation has a high loading rate that produces a shockwave in the surrounding reservoir resulting in local damage with little propagation away from the borehole. Conversely, propellant deflagration has a relatively low loading rate that proceeds without generating a shock wave, producing fewer but longer fractures. Due to their slow burn rates, propellants are not energetic enough to create adequate fracturing and shearing in hard-rock EGS environments (Grubelich and Thoma 2012; Grubelich 2015) but have shown some success in high-enthalpy hydrothermal systems in Iceland (Sigurdsson 2015). Materials that have reaction rates somewhere between detonation and deflagration are needed for widespread adoption of dynamic loading stimulation (Grubelich 2015).

Proppants are used as part of the stimulation process to help create and maintain reservoir permeability by holding fractures open after the stimulation conditions (pressure and/or temperature) are removed. Proppants are usually made of sand, bauxite, or glass, and are sometimes covered with a hardening resin. In 1979, the DOE sponsored ten stimulation experiments as part of their Geothermal Reservoir Well Stimulation Program (GRWSP) where seven of the experiments used proppants (Sinclair 1980; Entingh 2000). Post evaluation of these experiments showed that a majority of wells showed little or no increase in the productivity index, suggesting that the proppants used in the experiments may degrade over time due to the high temperature and saline environment (Mattson, et al. 2016).

There are three primary processes that reduce the effectiveness of proppants in geothermal environments (Sinclair 1980). First is that proppants such as sand and glass are brittle and subject to point-to-point loading that causes failure. Second is that chemical processes can cause stress corrosion cracking that can weaken the particle. Finally, for natural proppants such as sand, the proppants contain micro-fractures that are subject to failure under stress. Another issue associated with corrosion of proppants is that the material may dissolve over time and lead to the subsequent precipitation of secondary minerals that can plug the fracture system downstream of the proppant (Mattson et al. 2016). Studies have confirmed that there is still much uncertainty in how various proppants behave under different geothermal environments but there is a general consensus that sintered bauxite is the best performer to date (Sinclair 1980; Brinton, et al. 2011; Shiozawa and McClure 2014; Mattson et al. 2016) . Better understanding of the tradeoffs between increases in productivity and costs associated with the use of different proppants is a major gap in understanding (Mattson et al. 2016) and should be pursued through both laboratory experimentation and numerical modeling.

3.11. Stimulation Mechanism

The success of EGS is contingent upon the ability of the industry to predictably and reliably stimulate economic reservoir volumes from down-hole points of access. Thus the knowledge gaps in stimulation mechanisms as they apply to geothermal is a key issue. Currently, there are large gaps in our knowledge of the mechanism by which stimulation occurs; that is, is it from the creation of new fractures, from shearing existing fractures, or a combination of both (McClure and Horne 2014). Without this understanding, stimulation is a hit or miss activity with little or no guarantee of success (Jung 2013; DOE 2016). Prior to Fenton Hill, the 'hot dry rock' (HDR) concept was based on the idea that deep basement rock was mostly intact and virtually impermeable and that two wells could be drilled and then a series of fractures could be created using thermal stimulation to hydraulically connect the two wells (Jung 2013). However, results at Fenton Hill showed that basement rock contains a naturally occurring low-permeability fracture network (Kelkar, et al. 2016) to which many trace the genesis of EGS. In an EGS, the naturally occurring fractures need only to be hydraulically sheared to 'enhance' the permeability enough to make the system exploitable.

For decades, the hydro-shearing mechanism worked well to describe what was being seen in the field, although as more data have become available, the conceptualization of pure shear-based stimulation is being challenged. Jung (2013) examined injected fluid volumes, seismic cloud dimensions, and fracture characteristics of 21 stimulation experiments at 8 different sites (Falkenberg, Fenton Hill, Camborne, Hijiori, Ogachi, Soultz, Cooper Basin, and Basel) to conclude that there is 'no doubt' that the stimulation mechanism is best described using the 'wing-crack' model. The wing-crack model is used to describe material failure for inelastic, brittle materials under pressure where large dominant shear fractures do not propagate along their own plane but rather form tensile wing-fractures.

Using the results of 12 stimulation experiments from 10 different sites (Cooper Basin, Soultz, Fenton Hill, Hijiori, Ogachi, Desert Peak, Rosemanowes, Basel, Le Mayet, and Fjällback), McClure and Horne (2014) show that typically, flow from the wellbores is from pre-existing fractures, suggesting a high level of shearing, but that bottom-hole pressure exceeds the minimum principal stress and thus pressure-limiting behavior occurs, both of which suggests the formation of new fractures. They reconcile these conflicting observations by suggesting a mixed-mechanism stimulation (MMS) model whereby natural fractures are activated at the borehole and new fractures form away from the wellbore, through the concentrations of stress caused by the natural fractures opening and sliding. Using discrete fracture modeling, they conclude that certain conditions must exist for the MMS model to work, with pure shear stimulation becoming more dominant in locations near thick fault zones, and MMS more dominant in other locations.

In an attempt to further our understanding of the stimulation mechanism, Xie et al. (2015) reviewed hydraulic stimulation results from seven EGS projects (Fenton Hill, Rosemanowes, Soultz, Ogachi, Hijiori, Cooper Basin, Groß Schönebeck, and Basel), noting that the stress regimes are wide ranging from normal faulting to reverse faulting. They also found no correlation between stimulation success and the type of stress regime but do show that the in-situ stress conditions have an influence on the stimulated rock regions and the migration of induced seismicity. In a following paper, (Xie and Min 2016) create a hydro-shear model to predict the shear activation pressure and migration direction and compare those to stimulations done at Soultz, Basel, Rosemanowes, and Cooper Basin. Their results are generally consistent with observation although there are deviations with respect to the pressure loss along the fracture and wellbore, which might suggest that the pure shear model is missing the effect of new fracture formation at the sites.

Collectively, the studies summarized above suggest that the stimulation mechanism is not a singular model of shear or fracture but rather a combination of the two where the dominant mechanism is a function of the rock type, stress regime, temperature, depth, and stimulation method. Understanding the conditions and thresholds under which the various stimulation mechanisms occur will allow developers to optimize reservoir heat extraction through better well placement and orientation, and through more efficient and effective reservoir stimulation.

3.12. Hydraulic Performance

The ultimate goal of any geothermal stimulation effort is to enhance the permeability between the injection and production wells to extract heat in a manner that is economically viable and sustainable. Within the literature, changes in permeability are usually expressed as an injectivity/productivity index, which reflect the flow rate at a well per unit head differential. Injectivity and productivity are functions of the reservoir permeability, the radius of the borehole, and the length of the injection/production zone(s). Mathematically, they are equivalent in that for saturated systems where the pressure gradient between the well and the reservoir is less than the minimum principle stress, the governing equations do not care if the flow rate is positive or negative (above that level, injection will further enhance the permeability, which ends the equivalency with productivity).

It is important to note that injectivity and productivity reflect the permeability around a single borehole and do not indicate the potential to circulate fluid between an injection and production well nor do they speak of the quality of the fracture network that was created. From a circulation standpoint, the inverse of the injectivity/productivity index describes the resistance to moving fluid between two or more wells

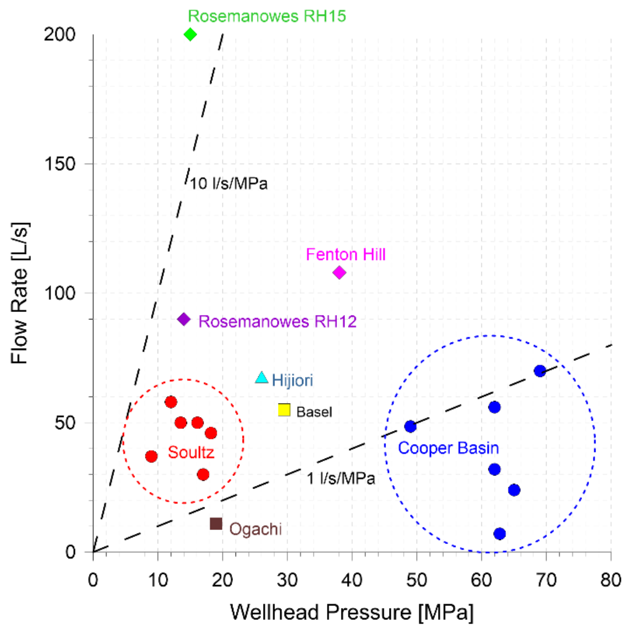

Figure 10 - Injectivity rates from previous stimulation tests. Encircled tests are associated with the same project. The black dashed lines represent injectivities of 1 and 10 L/s/MPa. Recreated from Xie, et al. (2015).

in an EGS system or to injecting and producing in a hydrothermal system and is the controlling factor in the amount of pumping that is required to operate a system. Unfortunately, there are few available data that compare the conditions before and after stimulation, and even less that compare the ability to circulate fluid between two boreholes.

As a comparison point for the balance of this section, it has been suggested that for an EGS system to be economically viable, it needs a total circulation of 45-90 kg/s at a temperature of 190 °C and parasitic losses to drive the fluid through the system at or below 0.1 MPa/l/s (Baria and Petty 2008; Jung 2013). Expressed as an injectivity, a value of 10 l/s/MPa has been estimated as the minimum value for economic competitiveness (Xie et al. 2015).

Almost all of the wells at Soultz have been hydraulically stimulated and in all but one case the injectivity was improved by 15 to 20 times, except in GPK-3, which improved by 1.5 times but also had significant permeability prior to stimulation (Baria, et al. 2006; Genter, et al. 2010; Held, et al. 2014). Chemical stimulation further improved injectivity another 1.15 to 2.5 times with final values reaching 4-5.0 l/s/MPa (Genter et al. 2010). The experience at Soultz clearly shows that stimulation can add significant permeability to the system, although the final values still fall short by about 50% of the target value.

In addition to investigating the stimulation mechanism, Xie et al. (2015) also examined the hydraulic performance of the seven EGS projects in their study showing that in all but one of the sites (Rosemanowes), the post stimulation hydraulic performance fell well short of the 10 l/sec/MPa target value (Figure 10). Their estimates are based on the pressure at the maximum injection rate during stimulation under the assumption that the stimulated permeability was maintained over the long-term.

3.13. Stimulation Costs

Unfortunately, there are very few data detailing stimulation costs for geothermal applications. For hydrothermal systems, Flores, et al. (2005) conducted an economic analysis for stimulation that determines the needed improvement in steam output to make stimulation worthwhile. Looking at the Las Tres Virgenes geothermal field in Southern California, they state a cost for acid stimulation of $2033 / m^3 of acid, which depending on how their numbers are interpreted, results in a total cost per well for acid stimulation ranging from $82,000 to $630,000. They also state that for wells in Iceland, acidizing runs about $20,000 per well.

Brown (1983) states that the typical cost for a hydraulic fracturing job ranges from $100,000 to $500,000, which are based on references he cites from 1982. Converting those costs to 2017 dollars (http://www.usinflationcalculator.com/) gives a range of $250,000 to $1,250,000 per stimulation.

Tester and Herzog (1991) examine the economics of EGS to develop a breakeven price for EGS by using data from six different EGS sites developed from 1979 to 1988 to estimate the stimulation cost per kWe installed as a function of the initial reservoir temperature. Their results show a linear trend ranging from ~$825 / kWe at 160 ^{o}C to ~$150 / kWe at 280 ^{o}C. Using the median installed value of 7 MW per well from Sanyal and Morrow (2012), this translates to stimulation costs of $10.4 million to $1.9 million per well at 160 ^{o}C and 280 ^{o}C, respectively (2017 dollars).

In their estimations of the cost of electricity for EGS and using stimulation costs at Soultz and Cooper Basin, Sanyal, et al. (2007) determine a minimum, most likely, and maximum stimulation cost per well of $500,000, $750,000, and $1,000,000, respectively.

Within the O&G industry, the U.S. Energy Information Administration (USEIA 2016) states that for onshore oil and natural gas wells, completion costs are estimated to be $2,900,000 to $5,600,000 per well (~55-70% of their total stated well cost), which includes fracking/stimulation costs. Unfortunately, the explicit cost of fracking/stimulation is not given. A news article on the CNBC website (DiChristopher 2017) refers to the Denver-based energy company, Lilis Energy, who recently solicited quotes for fracking that ranged from $2.2 to $3.2 million per well.

Given these results a baseline stimulation cost of $1,250,000 / well was passed to the P2P team for their analysis. While this is on the lower end of the values cited above, there are several key observations that led to this value. First is that the value is meant to represent a generic value across all rock types and energy sources (EGS and hydrothermal). Secondly is that like the drilling cost curves, the Baseline values are meant to reflect the current state-of-the-art and not the current average. Thirdly is that for the two studies that used actual geothermal stimulation cost data, the Sanyal et al. (2007) study provides the most direct estimate of stimulation costs and quotes a maximum value that is less than our Baseline cost. The other study to use geothermal stimulation cost data was Tester and Herzog (1991), who gave the costs in terms of stimulation cost per kWe. This likely over states the per well cost because the value is a function of the power output, which for the EGS systems used in the study were fairly small.

Another point of consideration is that estimations of water use for hydraulic fracturing range from 4,000 to 35,000 m^3 (1 – 9.2 million gallons) (Engler, et al. 2012; Scanlon, et al. 2014; Xie et al. 2015), which has its own purchase and disposal costs. It is impossible to tell if the stimulation costs referenced above include the cost of water, although for our Baseline value, it is assumed that the cost of water is included. Nevertheless, using the water-use rates and a water cost of $3 / bbl (AP 2013), water costs can range from $70,000 to $650,000 per well.

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4. MAINTENANCE / MANAGEMENT

4.1. Introduction

The primary goal of reservoir management is to maintain a rate of enthalpy production that is within the projects' design parameters over the life of the project. Reservoir management can be thought of as an extension of project engineering in that the latter addresses issues such as heat in place, permeability, well design, water injection and the like, while reservoir management is about optimizing those processes to match the goals of the project (Ungemach, et al. 2005).

There is considerable debate about whether or not geothermal energy is a renewable energy source (Ungemach et al. 2005; Rybach 2007; O'Sullivan, et al. 2010; Shortall, et al. 2015). The argument for or against this definition involves the time-scale in question. Estimates show that the rate of heat extraction at most geothermal energy fields exceeds the pre-development rate of heat inflow from depth (O'Sullivan et al. 2010), implying that geothermal energy *is not* a renewable resource. However, it can also be argued that geothermal heat replacement "will always take place, albeit sometimes at slow rates" (Rybach 2007) or be made "exploitable again in about a century" (Sanyal 2010), implying that geothermal energy *is* a renewable resource. While the argument is somewhat immaterial, the 'renewability' of the resource in terms of its productive life and the ability to regenerate itself is a direct function of how the resource is managed.

Axelsson, et al. (2001) make a distinction between renewable and sustainable energy stating that the renewability of an energy source is a function of the nature of the resource while its sustainability applies to how the resource is exploited. They also define a maximum sustainable energy production rate, E_o, below which it is possible to maintain energy production for an extended period of time, which they define as 100-300 years and for which in hydrothermal systems anyways, there is ample evidence to support (Stefánsson and Axelsson 2005; Steingrímsson, et al. 2006; Axelsson 2011). Establishing the value of E_o for a given system is difficult since the capacity of the system is usually not well known during exploration and initial production, although it can be expected to increase over time as knowledge about the resource grows and technology advances (Axelsson 2012).

Furthermore, geothermal reservoir sustainability does not necessarily have to mean that the mode of operation is the most profitable. In fact, for target lifetimes greater than 30-50 years, the importance of economics as compared to thermal sustainability diminishes due to the effects of inflation on the value of future earnings (Stefánsson and Axelsson 2005). As an example, at an inflation rate of 5%, the present value of a dollar that will be earned in 50 years is 9 cents, at 75 years is 2.5 cents, and in 100 years it is less than 1 cent. This implies that as a projects forecasted lifetime increases, estimates of sustainability transition from an economics problem at short time spans to more of an engineering and physics problem at long time spans. It should be noted that the present value as used here is based on the compounded inflation/discount rate and does not take into account the value of re-negotiating power purchase agreements at future rates. While it would seem prudent from a developer's point of view to maximize the economic return on investment, many governing bodies, such as in Iceland and New Zealand have policies in place to insure multi-generational sustainability of their geothermal systems (Steingrímsson et al. 2006; WRC 2016).

Figure 11 illustrates this tradeoff by showing the physical and economic performance of a hypothetical EGS system as a function of its long-term mass flow rate. The EGS system was simulated assuming an injection/production doublet, 500 m apart, accessing a total reservoir volume of 0.125 km^3 (500 m per side). The initial reservoir temperature is 200 ^oC and is at a depth of 4000 m. The plots were generated using the Gringarten solution (Gringarten, et al. 1975) assuming an injection temperature of 82.7 ^oC and a fracture spacing of 50 m. The calculations assume a wholesale energy price of $29.85 / MW-hr, a reservoir permeability of 2.86×10^{-15} m^2, and an inflation rate of 5%. Headlosses and temperature changes in the boreholes are ignored thus the only pumping requirements are those to offset the density difference between the injection and production wells and the headloss through the reservoir.

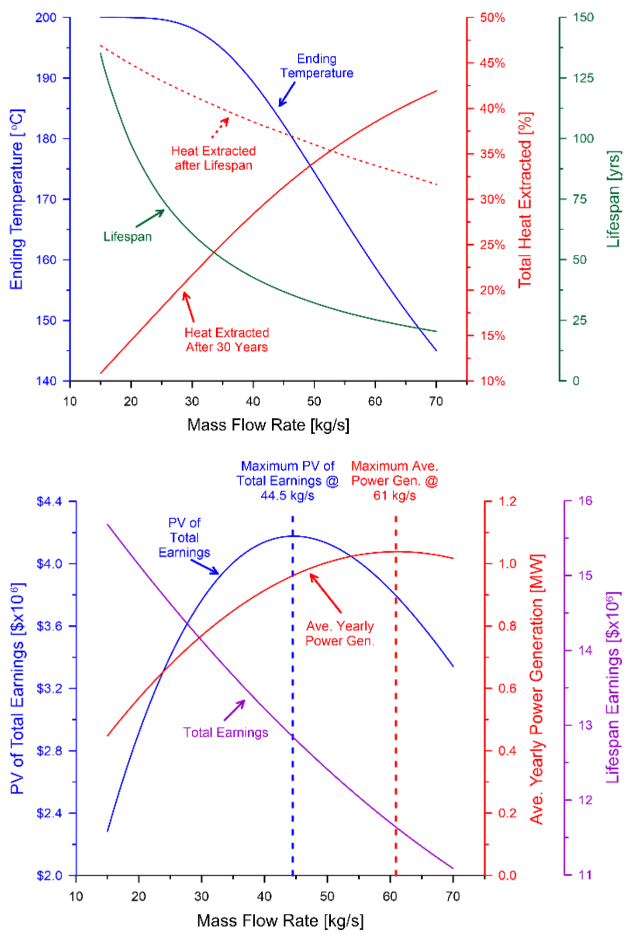

Figure 11 – Top: Physical performance. The ending production temperature after 30 years (blue), the percent of the initial heat in place extracted after 30 years (red), time to reach a production temperature of 170.2 °C (the lifespan – green), and the percent of the initial heat extracted after the lifespan (dashed read).

Bottom: Economic performance. Total earnings over the project lifespan (purple), present value of the total earnings (blue), and average yearly power generation (red). The operating conditions to maximize the present value of the total earnings (blue dashed) and the average power generation (red dashed) are also shown.

The top plot in Figure 11 shows the tradeoffs between the mass flow rate and the physical performance metrics of the system: the ending production temperature after 30 years (blue line), the percent extracted of the heat in place after thirty years (red line), the lifespan of the project (green line), and the percent extracted of the heat in place after the projects lifespan (red dashed line). The project lifetime was calculated as the time for the production temperature to drop to 170.2 °C, which is the default value used in GETEM for a reservoir with an initial temperature of 200 °C. The blue temperature plot shows a breakpoint at about 30 kg/s where the ending production temperature begins to drop off rapidly due to the interaction of the cooling fronts between the fractures. Conversely, the red total heat extracted plot (expressed as the sum of the heat extracted divided by the initial heat in the reservoir) is linear until about 40 kg/s at which point it declines as a first order function of the mass flow rate.

The heat extracted after 30 years (red dashed line) is shown as a comparison against the lifespan calculations. At the lower mass flow rates, the total heat extracted is less than 25%, meaning that assuming a 30 year lifespan for a system without optimizing the operations will severely under predict the systems performance.

With regards to the lifespan, we see that it varies from 135 years at 15 kg/s to 20.4 years at 70 kg/s. However, the total heat extracted as a percentage of the heat in place ranges from 47% at 15 kg/s down to 32% at 70 kg/s. From a management point of view, it is difficult to know if it is better to extract 47% over 135 years or 32% over 20 years. This is in contrast to the O&G industry where the payback times for a single well are extremely fast and thus O&G extraction rarely needs to account for this type of tradeoff.

The bottom plot in Figure 11 shows the tradeoffs between the mass flow rate and the economic performance metrics: the present value of the total earnings (blue line), the average yearly power generation (red line), and the total earnings (purple line). All metrics are relative to the 170.2 °C lifespan of the project. The plot also shows the mass flow rate required to maximize the present value of the total earnings (blue dashed line) and to maximize the average yearly power generation (red dashed line). Comparing the earnings line (blue line) in the bottom plot to the lifespan percent heat extracted line (red dashed line) in the top plot shows the effect of the declining value of future earnings. The 15 kg/s mass flow rate extracts more heat (47%) and has the highest lifespan earnings ($17.4 million) than the higher mass flow rates, but the declining present value of future earnings results in the least present value of the lifespan earnings ($2.3 million). The average yearly power generation is the smallest at 15 kg/s (0.15 MW), peaks at about 61 kg/s (1.04 MW) and is slightly less at 70 kg/s (1.02 MW). The peak at 61 kg/s is a result of the increased pumping requirements at the higher mass flow rates. The peak in the present value of total earnings at about 45 kg/s is also a function of the increased pumping requirements as well as the relationship between the lifespan of the reservoir, the total earnings, and the inflation rate.

Figure 11 is meant to illustrate the complex dynamics between the various economic and physical processes of a simple EGS system. One would expect a developer to manage the reservoir to maximize their return on investment (operating at the peak of the present value of total earnings curve) by extracting at 45 kg/s for 37 years (Gallup 2009). However, from a sustainability perspective, it is difficult to know if that is the best option. For instance, operating at 25 kg/s results in 80% of the present value of earnings at 45 kg/s ($3.4 million versus $4.2 million) but doubles the lifespan of the reservoir (75 years versus 37 years). Alternatively, one may choose to produce at the maximum power (61 kg/s), which reduces the project earnings by 8% (to $3.8 million) and the lifespan by 30% (to 25 years), but has more certainty in the outcome due to the shorter lifespan. It is at this level that the decision makers must consider the uncertainties associated with their projections and weigh the probabilistic risk of various future scenarios (Lowry et al. 2012; Kalinina et al. 2014).

Furthermore, when evaluating the sustainability and tradeoffs of geothermal system operations, the focus need not be on a single system or even a single project. The combined production from several systems controlled by a single power company can be operated in a cyclical manner over time whereby one system is 'recovering' while another system is performing at rates higher than what would be considered sustainable if it was evaluated individually (Axelsson 2012). This concept also holds true for power companies that have diversified portfolios such as geothermal and hydroelectric. Having geothermal as a baseload source with a high utilization factor provides considerable flexibility with regards to how other energy sources are operated.

A unique attribute of geothermal energy production is that a geothermal reservoir has dual characteristics: energy flow and energy storage (Axelsson 2010). Energy storage represents the heat stored in the rock while energy flow represents the energy recharge from 'outside' the reservoir as well as the energy extraction via the production wells. The closest analogy is hydroelectric power generation where river inflows to a reservoir represent energy inflow, the reservoir represents the stored energy, and releases through the dam represent production outflow. The energy of hydroelectric power is the gravitational potential energy of a unit mass of water whereas the energy in geothermal is heat. Continuing with the hydroelectric reservoir analogy, it is easy to see that if the average water release exceeds the average inflows over time, the reservoir will eventually empty and energy production will need to decrease or stop until the reservoir fills again. The time scale for when the reservoir empties is a function of the difference between the average inflow and average outflow and the amount of storage in the reservoir. This dynamic is the same for a geothermal reservoir except that the mechanism of 'refilling' the reservoir is through heat conduction, convection, and/or advection, which by some estimates can take centuries (Sanyal 2010). Depending on the system, advection and/or convection can maintain heat in the system for centuries, while conduction is orders of magnitudes smaller. As an example, the time for the EGS example in Figure 11 to recharge itself to 97% of its original capacity is on the order of 500-700 years via conduction only.

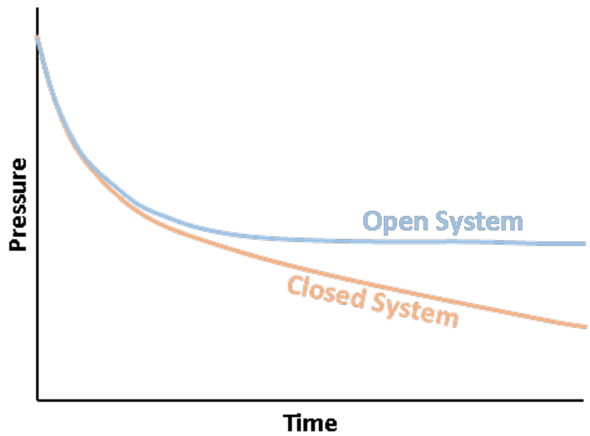

Figure 12 - Comparison of the pressure decline over time between an open and closed system. Recreated from Axelsson (2008).

This dual flow and storage characteristic allows geothermal reservoirs to be defined on a scale from 'open' to 'closed' (Axelsson 2011) as a function of the boundary conditions of the reservoir (Figure 12). When production starts, open systems will experience an initial decline in reservoir pressure that stabilize over time while closed systems will experience a continuous decline. The pressure stabilizes in an open system due to recharge equilibrating with the mass extraction. Closed systems on the other hand will require reinjection to stabilize the pressure. Examples of open and closed systems are the Laugarnes field in SW Iceland and The Geysers in California, respectively (Steingrímsson et al. 2006). In the sixties, the Laugarnes field increased production by an order of magnitude due to the addition of downhole pumps that resulted in a pressure drop of about 120 m of water. However, since that initial drop, the pressure has stabilized and the field has maintained production at or near the new level ever since. The Geysers on the other hand had an era of rapid development that over extended the field and from about 1985 to 1995 the field experienced dramatic pressure drops that could only be mitigated through re-injection and a drop in the peak production rate. EGS is considered a special case of a closed system since it includes reinjection into the reservoir as part of its standard operating procedure.

The distinction between closed and open is important because it highlights the importance of understanding the hydro-thermal characteristics of a reservoir before production occurs so that the reservoir can be properly managed. However, the only method to develop this understanding is by monitoring the pressure response of the reservoir from long-term production. A development and management method that would have served The Geysers well and that has since become common practice is the stepwise approach. The premise of the stepwise approach is to initiate production from the field as soon as possible after the first successful wells are drilled (Stefánsson and Axelsson 2005). The production-response history of the reservoir during the first development step is used to estimate the size of the next development step. The method has several key advantages:

1. It keeps the time between drilling and production short, allowing the return on investment to begin immediately.
2. The reservoir response is tested with actual production from the field, meaning that the testing phase is an incoming-producing phase as opposed to an expense phase.
3. Over investment is more easily avoided.
4. Surface and field equipment will be better matched as enthalpy changes over time.

A technology that can facilitate the stepwise approach is the use of wellhead generators, which can be attached directly to the wellhead to begin generating power prior to the completion of a centralized power plant. These have been deployed in limited areas (Sutter, et al. 2012) but can allow developers the ability to start producing power and begin paying back capital expenditures as soon as possible. At least as important is the ability to gather key reservoir engineering data early on while drilling development wells (even pseudo interference testing) that can pay back dividends in terms of the conceptualization of the field and its long-term operation.

The balance of this section describes three required elements for the successful management of a reservoir (Stefánsson and Axelsson 2005; Axelsson 2010, 2012):

1. Characterizing the system, especially the permeability structure and boundary conditions.
2. Monitoring the response of the reservoir to long-term energy production.
3. Modeling the reservoir to match the historical response and to make predictions of future conditions under different scenarios.

4.2. Characterization

Characterization determines the underlying nature of a system. For a geothermal reservoir, characterization includes quantifying the parameters that determine the likely level of success (or failure) that can be achieved at a site. Initial characterization of a geothermal field is carried out during the exploration, development, and initial production phases, and then should be continuously updated with new data as production continues over time. Four methodologies are used to characterize a reservoir: geophysics, geology, geochemistry, and remote sensing (DOE 2012). A fifth exploration method, called cross-cutting, combines the four methods to develop more complex and complete characterizations. The underlying technologies in these areas are covered by the Exploration Task and are not described again here.

The type and quality of the characterization can have a large impact on how a reservoir is conceptualized and managed. For hydrothermal systems, the focus should lean more towards *effective* properties of the reservoir, such as the productivity/injectivity index and regional hydrogeological parameters, especially boundary conditions. EGS on the other hand requires a higher level of detail such as the facture and aperture distribution and the reservoirs impedance to flow between wells (EGSRMO 2007; Li, et al. 2015). More than the classification of EGS or hydrothermal, the distinction should be based on the degree to which a system is open or closed, the temperature of the recharge fluid (either natural or injected), and the degree to which the recharge fluid is in chemical equilibrium with the surrounding rock. In open systems, the general assumption is that groundwater is entering the reservoir as part of the regional groundwater flow or through injection of water that was previously in contact with the reservoir for an extended period of time (i.e., production water) and thus is in thermal and chemical equilibrium with the rock. In closed systems, the production fluid enters the reservoir via injection and in most cases is not in thermal or chemical equilibrium with the rock (EGSRMO 2007), which in turn brings about thermal, hydrologic, mechanical, and chemical (THMC) effects that must be considered for long-term management. In reality, the actual field response lies between these two extremes.

4.3. Monitoring

Monitoring serves two purposes in reservoir management; 1) it provides the current status of the system, and 2) it creates a record of reservoir responses over time that can, through the use of inverse modeling, aid in better characterization and hence better management of the system. Monitoring allows for optimizing mass flow rates, adjusting to meet changing thermal and chemical conditions, and identifying issues with premature thermal breakthrough. Monitoring has also been pointed to as a mechanism for adjusting to non-operational stressors, both natural and man-made (Heasler, et al. 2009). Natural stressors include changing weather patterns, climate change, or earthquake activity. Man-made stressors can include development of nearby O&G reserves, geothermal energy, or pumping water wells. Thus, continuous long-term monitoring and selective periodic monitoring should be central to any reservoir management program.

To be effective, a monitoring program should involve continuous monitoring of production and injection wells for mass flow rate, wellhead pressure and temperature (or enthalpy in the case of 2-phase flow), and chemistry (Haizlip 2016). Observation wells should also be included to monitor spatial and temporal variability in reservoir temperature and pressure. An often overlooked piece is to begin continuous monitoring as early in the project as possible to provide a pre-development baseline from which trends can be established (Heasler et al. 2009). Periodic monitoring should also be conducted that includes PTS (pressure-temperature-spinner) surveys to examine flow rates along the borehole, interference and pump testing, gravity, caliper logs, and tracer tests (Drenick 1986; Plummer, et al. 2010; Haizlip 2016; Nishijima, et al. 2016). Periodic monitoring should be used for early detection of problems such as localized changes in permeability or thermal breakthrough, that would be detected later or not at all through the continuously monitored attributes.

Reactive tracers have been long recognized as a means of measuring a wide range of reservoir and hydraulic conditions that could not otherwise be measured and have been called out as a priority development area to maximize the economic potential of geothermal energy production (EGSRMO 2007). “Smart” tracers can be used for determining sub-surface flow patterns, measuring heat-exchange surface area, and finding the extent of the thermal front. Despite their great promise, numerical and field studies have shown that current capabilities only allow for the estimation of effective or average parameters (Plummer et al. 2010; Hawkins, et al. 2016). One approach to overcome this limitation is the use of tagged nanoparticles that places chemical ‘tags’ into proppants to provide detailed information on subsurface flow patterns for EGS systems (SNL 2014). Another approach being investigated is the use of threshold reactive tracers that uses designed nanoparticles with encapsulated reactants that react at a threshold temperature to determine the location of a thermal front (Ames, et al. 2015).

As is pointed out in the literature with regards to tracers (EGSRMO 2007; Ames et al. 2015; Hawkins et al. 2016) and as is discussed in general below, the use of tracers requires a simultaneous advancement in thermal-hydraulic-mechanical-chemical (THMC) modeling that can inversely recreate the subsurface conditions that reproduce the tracer signal. While this capability exists for shallow groundwater applications, the ability to do this in complex geothermal environments is not yet available.

4.4. Modeling

It is difficult to manage a reservoir over time without a working conceptual model of the system. It is preferable, especially through exploration and into early stage development and operations to have multiple conceptual models that can serve as multiple working hypothesis of what the fluid flow and reservoir physics are likely to be. Conceptual models allow an analyst to make better sense of data anomalies and are ideally constructed by stacking different data sets in the context of a physical model to bound and constrain target parameters (Cumming 2009). These can be tested as data are acquired and the verifiable elements of those multiple models which emerge help the operator to progressively converge to a singular and very robust conceptual model of the system. This is an invaluable tool for field management and improved well targeting success. Models are used to define the reservoir requirements, aid in design of the stimulation and characterization of the reservoir, help plan reservoir operations, calibrate injection water chemistry, and explore the potential of alternative scenarios (EGSRMO 2007). An equally important role is that models are necessary for eliminating physical conceptualizations and management options that are physically and/or practically not possible, which allows managers to focus on the most likely scenarios.

Characterization and monitoring programs and numerical simulation should be used together and evolve collectively over time. In the geosciences, the process usually starts with forming simple models based on the initial data, and then adding layers of complexity over time as the modeling and monitoring results add to the understanding of the system (EGSRMO 2007; Axelsson 2012; Kühn and Altmannsberger 2016). This allows for both the monitoring program and the modeling effort to continuously improve over time. It also means that expectations of the reliability of early model predictions should be kept low (EGSRMO 2007).

Modeling requirements between hydrothermal and EGS are somewhat different although there are many more similarities than differences (Xing, et al. 2015). It has been presented that the effective management of hydrothermal systems can be achieved with models that simulate only pressure and temperature with spatial resolutions that are relatively course (Stefánsson and Axelsson 2005; Axelsson 2012; Shortall, et al. 2015). On the other hand, models of EGS systems require the simulation of complex and coupled THMC processes that are both data intensive and computationally costly to simulate. Xing et al. (2015) list the following challenges for EGS models that are not required in hydrothermal systems:

1. The full coupling of geomechanical deformation and rock stress with multiphase thermal-fluid flow and chemicals
2. The ability to simulate detailed chemical interactions between aqueous fluids, gases, and mineral assemblages in fully-coupled, three-dimensional flow and mass transport models
3. Meshing is difficult and time consuming in fractured dominated systems and especially for systems that will experience fracture propagation over time
4. There is no mechanism for evaluating rupture and permeability distributions over time
5. Inability to automatically convert complicated fracture patterns to the computational model
6. Lack of multi-scale or parallel computing tools

In our opinion, the challenges described above are somewhat over-stated and while they are almost essential to get the EGS industry off the ground, they can be just as important for optimizing conventional hydrothermal systems. The payback to the industry in meeting these challenges and applying them to hydrothermal systems can be realized nearly instantaneously in the form of increased power production without any other major technology advancement and thus should be of high priority for research investment.

As implied above, numerical models come in a wide range of complexities, from simple analytical expressions that can be solved with a calculator, to highly detailed, three-dimensional representations that must be solved on a super-computer. The choice of model is dependent on the system being modeled, the application (discovery, forecasting, decision support, etc.), the time scale, and the available data. Generally, simpler models have smaller data requirements than more complex models and are quicker to set-up and execute. For that reason, models should only be as complex as needed. Simpler models can be used to test sensitivities before incorporating specific processes and/or parameter values into more complex models, which is common practice in most modeling applications, including geothermal.

In the end however, the goal of modeling for reservoir management is to 'turn information into insight' such that the responses of the reservoir to different operational scenarios are understood in metrics that are meaningful to the decision maker. For instance, while it is important to understand fracture propagation in an EGS system over time, its importance in reservoir management is based solely on how that understanding translates into the socio-economic metrics from which management decisions can be made. Thus, the benefit of modeling lies in the ability to optimize the system to allow decision makers to make their own determination of how they want to balance the tradeoffs, such as those illustrated in Figure 11. In simpler terms, decision makers do not care so much about the physical details of the system but rather how those details impact their ability to generate power and manage the system over time.

Another important application of modeling is the ability to propagate and quantify uncertainty (Lowry et al. 2012; Scholtysik 2015). By incorporating uncertainty into the input parameters of a model, the outputs can be expressed in a probabilistic manner that shows the most probable outcome within the range of possible outcomes given the uncertainty (Figure 13). This approach has been tested for management of hydroelectric power systems where ensembles of future climatic conditions are used to manage the system within an acceptable level of risk (Lowry, et al. 2014) and for applications to model prediction and input uncertainty in EGS (Lowry, et al. 2010; Lowry et al. 2012). Improving upon this capability is imperative if risk-based reservoir management is going to be exercised.

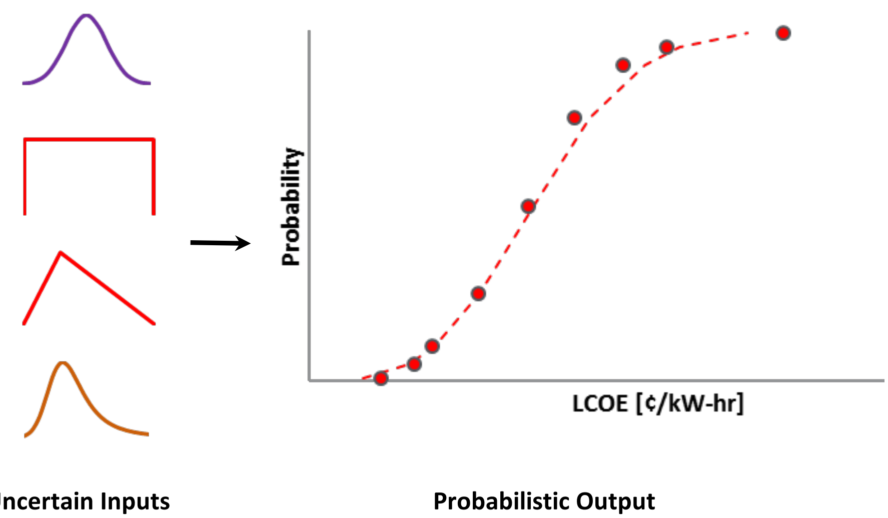

Figure 13 – Models are used to 'translate' uncertainty in modeling parameters into probabilistic output that shows the most probable outcome within the range of possibilities.

Another important aspect of uncertainty modeling is the capability to produce Pareto optimal solutions that show the tradeoff between multiple objectives as a function of uncertainty, operating scenarios, or both. A Pareto 'front' is defined as the demarcation where an improvement in one objective can only be made with a decline in at least one of the other objectives (Figure 14). Reservoir management is inherently multi-objective in that managers are continuously balancing multiple objectives all of which have varying degrees of integration and correlation. When used to examine uncertainty, Pareto optimal solutions quantify how uncertainty influences the dynamics between the decision objectives. This provides managers with the ability to focus efforts on reducing uncertainties that have the largest influence on the decision space. When used for scenario testing, Pareto optimal solutions show the tradeoffs between multiple objectives as a function of a variety of different scenarios. This allows managers to choose scenarios that best fit their 'real-world' experience, which might not necessarily be the scenario that is the most mathematically optimal. The application of the Pareto concept has been successfully applied in the design of geothermal power plants (Gerber and Maréchal 2012; Clarke 2014; Feng, et al. 2015) but has not been adopted in reservoir management. We believe that reservoir management could benefit from tools that provide a more rigorous treatment of uncertainty.

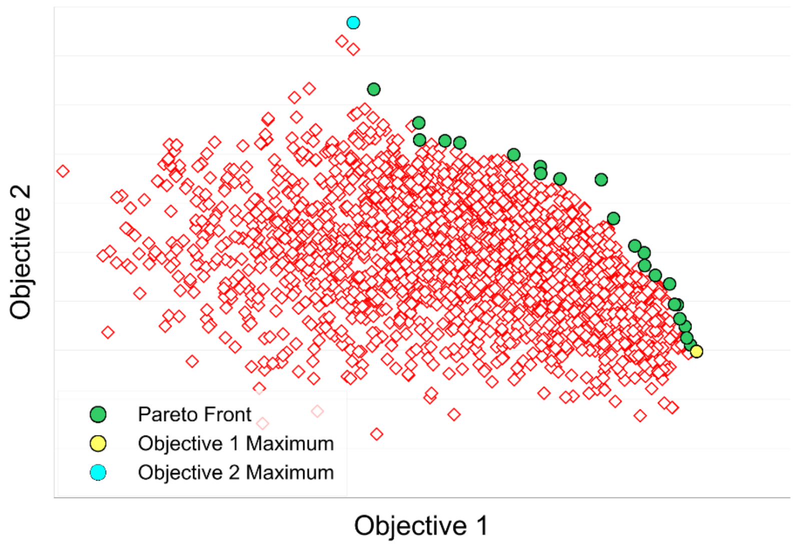

Figure 14 - Pareto optimal solutions show the tradeoff between multiple objectives as a function of input uncertainty and/or scenario testing. The Pareto Front is the line where an improvement in one objective can only be achieved by a decrease in one or more other objectives.

From a 'blue-sky' perspective, the holy-grail of geothermal modeling is a fully integrated reservoir, power plant, and economics model that includes the full suite of THMC processes and temporally varying dynamics. The importance of numerical model development is reflected in the time and effort that the O&G industry has put into creating integrated software that meets this standard. A good example is Schlumberger's Petrel E&P modeling framework that brings together data management, drilling, geology, geophysics, and reservoir engineering models in a single platform to more efficiently identify and access petroleum reserves (Petrel 2017). Within the groundwater community, the Joint Universal Parameter Identification and Evaluation of Reliability Application Programming Interface for model analysis (Jupiter-API) was created as a platform to bring together disparate numerical models of sub-surface and surface flow, transport, and water quality models to analyze their collective dynamics and sensitivities (Banta, et al. 2009). For the geothermal industry to develop this capability, they would first determine the set of systems and processes to be modeled, inventory the available models, develop models that are not available, and then integrate the suite of models within a single platform. While this is a steep hill to climb, the benefits to the industry could be significant and long lasting.

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5. OTHER CONSIDERATIONS

5.1. Thermal-Hydrologic-Mechanical and Chemical Processes

5.1.1. Introduction

'THMC' represents the Thermal-Hydrologic-Mechanical and Chemical cross coupling of processes associated with the flow of fluids in a geothermal system. The rate of energy production in a geothermal system is dependent on this complex and long-term interlinking of processes, which may significantly influence a projects' economics during its usable lifetime.

In most geothermal systems, the distribution of fracture permeability, natural or created, determines the pathways for fluid flow between an injection and production well. In the absence of any thermo-physical or chemical processes, the lifetime of a low-porosity, hard rock reservoir is determined by how long heat can be efficiently conducted to heating geothermal fluids flowing along the fracture networks connecting the injection and production wells. However, what may be considered an ideal distribution of fracture permeability for extracting heat at the beginning of a reservoir's lifetime is eventually subject to significant modification by THMC processes. These modifications result in changes in both permeability and porosity and are a function of the degree to which the injected water is in chemical and thermal disequilibrium with the formation. Computer simulations are now beginning to demonstrate how different facets or aspects of THMC can affect heat production over time beyond those decreases associated with simply depleting the thermal regime.

The example shown in Figure 15 illustrates how THMC can influence the production temperature drawdown in the geothermal system. Without considering coupling between the thermal and mechanical or stress regimes (i.e., THM), production temperatures were found in this example to be virtually constant out to about 12 years and then only falls off gradually after that time. However, when coupling between the thermal and mechanical regimes is considered, the thermal plateau is significantly shorter, only about 6 years, followed by a steep fall off of production temperature. This THM behavior is the result of more rapid cooling of the higher flow rate portions of the fracture network. The lower temperatures cause thermal contraction, which increases the fracture apertures and further channelizes the flow into these cooler zones creating even higher cooling rates of the rock mass.

This is a simple model considering only the thermal and mechanical regimes and does not take into account the addition of new fractures that may occur due to changes in the stress field from cooling. Additionally, THC processes are associated with chemical and thermal differences or disequilibrium between geothermal fluids and the host regime through which they flow. It is anticipated that a better understanding of the cross-coupled processes of THMC (e.g., THM and THC) will be useful for modifying or managing the undesirable flow-channeling aspects of pure thermo-mechanical coupling alone.

Seismicity has received a lot of attention in conjunction with injecting and extracting fluids during geothermal energy production (e.g., Sewell, et al. 2015). Thermal stresses resulting from the injection of cool fluids can build to the point where thermal-stress-induced fracturing and micro-seismicity occur. In addition, pumping fluids into fractures can reduce normal stresses on the walls of the fractures causing shear stresses that are already present to lengthen the fractures by sliding or tearing (e.g., shearing induced) or alternatively open fracture apertures sufficiently to propagate over-pressured fractures (e.g., tension induced). While seismicity may represent a concern regarding stakeholders' response to the presence of a producing geothermal system, the presence of seismicity interpreted in the context of THMC processes can provide an enlightening window into the response of a geothermal regime to the pumping and heat transfer operations associated with energy production.

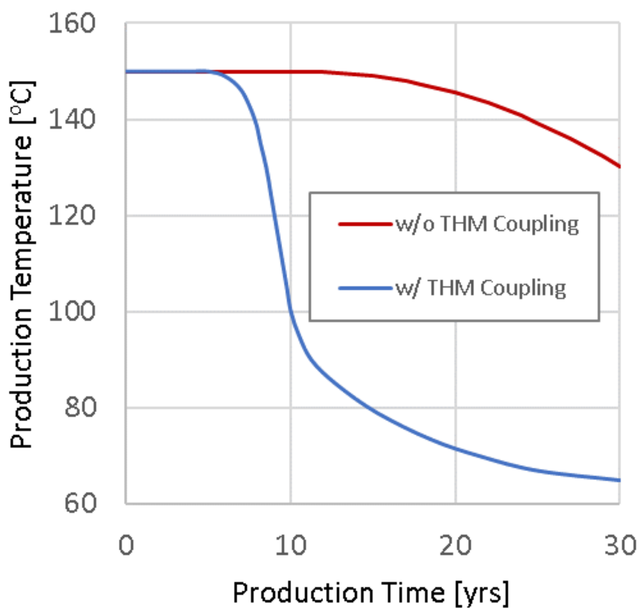

Figure 15 - Production temperature versus time for two different cases assuming the same initial fracture network. The simulation resulting in the red line results from thermal depletion only and does not include thermo-mechanical coupling. The blue line considers the effect of thermo-mechanical coupling in the hydrologic regime or THM. Recreated from Fu, et al. (2015).

Ultimately, THMC introduces dynamics into the operation of a geothermal system, whether EGS or hydrothermal, that cannot be ignored, especially over the long term. Predictive and diagnostic tools, such as computer simulators, which include the most important effects of THMC are needed for both the design of a producing geothermal system as well as its management during the operating years. As part of the management component, it will be very beneficial for ensuring the long term thermal output to better understand, through simulations supported by lab and field -based experiments, how different facets of THMC might be manipulated or managed to reduce or eliminate some of its negative effects (e.g., using chemical precipitation (THC) to offset the undesirable growth of fracture apertures (THM) due to cooling or manipulating the production of additional fractures through thermal stimulation). Additionally, a variety of methods have been proposed for the manipulation of the flow and temperature regimes once a path forward for extending the lifetime of the system has been determined.

Because the realistic characterization of a geothermal regime, which is needed by any predictive or diagnostic modeling effort, necessarily involves either introducing unknown or poorly determined parameters into the calculations, the effect of parametric uncertainty on the results should always be considered. Current uncertainty quantification (UQ) methods (e.g., Lawrence Livermore National Laboratory's (LLNL) PSUADE program by Tong 2011) have resulted in the capability to provide a probabilistic context for evaluating the likelihood of a diagnosis or prediction of a system's response.

5.1.2. EGS / Hydrothermal Regimes and THMC

Significant induced flow and heat production in hydrothermal systems may cause sufficient deviations from the near-equilibrium thermo-mechanical-chemical state of the system that the influence of THMC on productivity eventually becomes apparent. On the other hand, EGS represents a geologically short-term and more extreme perturbation of a subsurface fracture-dominated regime and begins its life in thermo-mechanical and thermo-chemical disequilibrium, raising the possibility that strong THMC responses may occur to drive the modified system towards a new equilibrium. Answering how THMC responses to introduced disequilibrium are most likely to affect the efficiency of output in both EGS and hydrothermal energy production is needed for any meaningful prediction concerning time-dependent changes in the long-term behavior of a commercial geothermal site.

At present, any EGS design engineer or manager is faced with the multiple challenges of having 1) only very limited access to parameters defining a geothermal regime, often only through information from well-head sensors or responses to changes in production, 2) a less than complete understanding of how

THMC processes are likely to affect production during the life of the system and 3) the intuition and practical ability to manipulate or manage the evolving system to enhance long-term output. We consider how we can address the first two challenges by using computer simulations constrained by data obtained from constantly improving monitoring techniques, to estimate the likelihood of a certain system response. To meet the third challenge, we provide a brief example to illustrate a possible approach of evaluating changes in a producing system along with application of flow-management methods that have been suggested to maintain output.

For EGS development, the most important objective is permeability enhancement in a large volume of rock that is amenable to long-term fluid circulation without significant thermal or production decline. As Figure 15 illustrates, our current understanding of THM processes suggests that thermo-mechanical coupling will tend to reduce the production life of EGS in the absence of other mitigating effects. Figure 16 illustrates the cooling caused by flow-channeling in a fracture regime that might occur between an EGS injection and production well over a period of 30 years. Simulations show that localized cooling, resulting from always present preferential flow in the network of fractures at early times, modifies the stress field such that more flow is channeled into the coolest regions of the system while being shut off from the hottest parts by compressive stresses that shut down fracture flow there. The figure further demonstrates how sophisticated computer simulations can serve as a “window” showing what is happening in complicated THM situations between injection and production wells addressing challenges 1) and 2) above.

The flow channeling simulation described here considers only one type of coupling – the thermo-mechanical, which is not necessarily the whole picture. Only detailed THMC simulations that consider the simultaneous cross-linking of thermal, mechanical and chemical regimes can provide a meaningful view into the processes that future EGS design engineers and managers need to understand to optimize the design and long-term operation of an EGS site. This type of modeling is a prerequisite to mastering the 3rd category of challenges.

5.1.3. Need for Detailed THMC Simulations Using Observations

Important design considerations such as planning the well depth and well orientation during the design process require knowledge of the stress field as a function of depth and temperature, the permeability structure, fracture orientations/densities, temperature gradients, etc. Because these data are necessarily collected at discrete points through borehole imaging, analysis of fracture breakouts, and flow testing, there is often much uncertainty as to their spatial extent outside the wellbore. Since a well must be drilled to determine this information, it is not possible to have direct measurements at each point desired. Fortunately, THMC models can incorporate discrete data (e.g., pressure, temperature, permeability, fracture aperture and density, etc.) and represent the geologic structure in 3-D, to more efficiently predict the larger scale reservoir response to stimulation of wells having different orientations, pressurized intervals, and pressure increase scenarios. Furthermore, the models can directly capture the effects of thermal versus pressure stimulation, as well as the influences of fluid chemistry on physical properties of the fluid (e.g., viscosity and density) and potential effects of mineral dissolution or precipitation in fractures around the wellbore. Reactive, isotopic, and conservative tracer tests can be modeled concomitantly with fracture stimulation so that a fully consistent analysis can be made (rather than employing simpler analytical models), clearly addressing challenges 1) and 2). Alternative and/or stochastic models can be used to improve confidence prior to drilling new wells, and planning stimulation strategies.

For example, at the DOE Newberry Volcano EGS Demonstration Site, Lawrence Berkeley National Laboratory simulated the THMC response during the 2014 stimulation and matched the early increase in

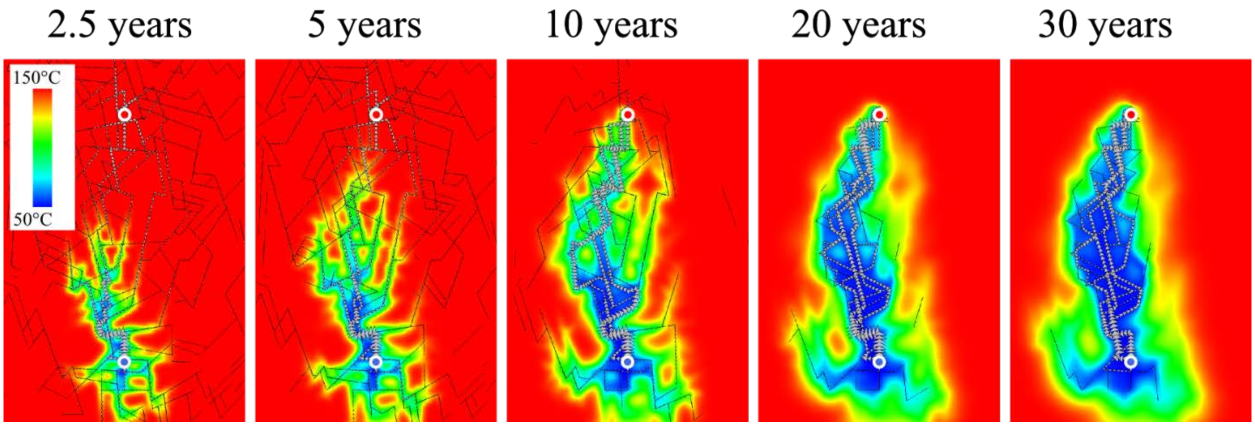

Figure 16 - Forced flow from the injection well (bottom) through the fracture network causes a cooling front to migrate towards the production well (top) with breakthrough between 5 and 10 years. Cooling opens fracture apertures which enhances flow through the regime which is already cooler. Cooling increases compressive stresses outside cooled zone which shuts down flow in fractures at the warmer periphery of the zone. The resulting flow channeling produces cooler water sooner at the production well as shown in Figure 15. Simulations performed with LLNL GEOS. From Fu et al. (2015).

injectivity (3-4x) owing to a combination of thermal and shear stimulation around the well. After about 8-9 days of injection, although microseismicity continued to increase over a radius of about 200 meters from the wellbore, the injectivity did not increase, which was also captured by the THMC code (Sonnenthal et al. 2015, Figure 17). The take-home point is that THMC modeling supported by wellhead data can be used in designing and optimizing drilling and stimulation programs.

5.1.4. Managing THMC Processes to Optimize EGS Production

Assuming the ability to perform full THMC simulations that address cross-linked THM and THC processes, we suggest how borehole-monitoring methods and permeability manipulation might be used in the future to prolong the life of an EGS site as an example of confronting the 3rd challenge above. It has been observed in fracture dominated systems that as the production temperature declines, the resistance to pumping for a given injection rate also falls off, which is consistent with the flow channeling effects observed by Fu et al. (2015). A periodic survey of the EGS flow regime, using particle tracers injected into the production well and capable of indicating temperature ranges characteristic of their flow paths (Redden, et al. 2010), could be used to support the operator's estimates of the rate of channeling at the site. A simple model suggests that the rate of decline with time in the ratio of high temperature (restricted flow in zone of compression) to low temperature (channeled flow) tracers recovered might be used to estimate production longevity as well as the best time to intervene in the THMC evolution. Changing fracture permeability to eliminate channeling by mineral dissolution and precipitation has been considered by the enhanced oil and gas recovery literature and is now being evaluated for geothermal applications (Plummer et al. 2010; Rose, et al. 2010). It is within the purview of THMC models to determine if and how an EGS site chemistry can be modified to allow chemical precipitation to be "played" against flow channeling. Plummer et al. (2010) lists different techniques for partially plugging a site with injected material including silicates to stop channeling or "short circuiting" of flows.

5.1.5. THMC Models for Hydrothermal Systems

Geothermal reservoirs sited in hydrothermal systems have different issues than low permeability, low water content, EGS reservoirs. In particular, finding and predicting the response of permeable zones that remain permeable over decades of pumping and reinjection requires prediction of the pressure and

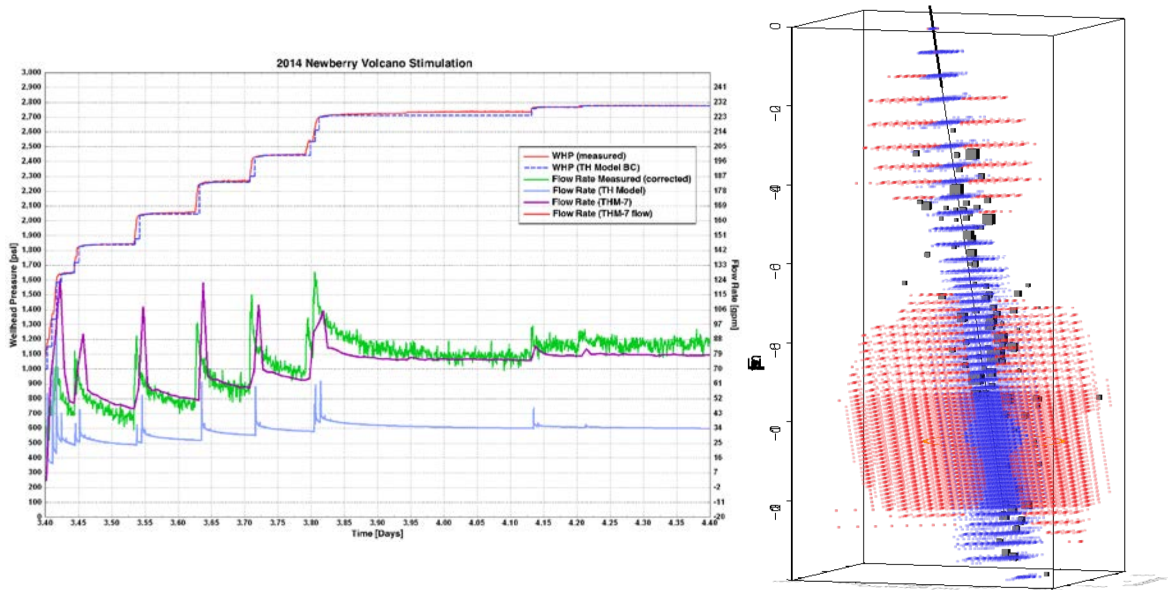

Figure 17 - (Left) Wellhead pressure (measured and model boundary condition), measured flow rates (green), TH model with no change in permeability (pale blue), THM model (purple), and continuation of THM assuming no further permeability increase (red). (Right) THM model compares seismicity with stress field. Thermal contraction is blue zone while compression is red. Most of the micro-earthquake (MEQ) activity appears to be correlated with the zone of thermal contraction dying out with distance into the zone of compression from this cooler zone (Sonnenthal, et al. 2015). As discussed above, MEQ activity can be understood in terms of THM simulations providing a means of understanding the dynamics of an EGS site.

mechanical response during production, whether pressure declines are reversible due to mineral scaling effects on permeability around and in wells. Environmental effects such as micro-seismicity, ground subsidence, wellbore failure are important issues involving THMC processes that require quantitative management.

Whereas, pressure declines and mechanical effects on producing geothermal reservoirs are well-known, as well as wellbore scaling, the chemical effects on permeability far into the reservoir are difficult to characterize using standard reservoir modeling tools. An example of THMC modeling of a heterogeneous injection and production over 2 years showing regions of calcite dissolution and precipitation in a rhyolitic tuff host rock is shown in Figure 18 (Sonnenthal et al., unpublished work from EGS Validation project). Using new parallel simulation tools such as TOUGHREACT-ROCMECH, we can finally treat these problems that were primarily in the area of fundamental research to practical reservoir modeling. In this regard, such sophisticated THMC models represent a stochastic view of the situation beyond the wellbore.

5.1.6. The Future of THMC Analysis

In conclusion, we have attempted to “look ahead” within the context of geothermal reservoir design and management to identify challenges that exist for EGS/hydrothermal as well as possible paths forward for developing and operating an efficient long-term geothermal heat extraction system. Research to date indicates that THMC processes make up many of the challenges confronting long-term and efficient operation of a geothermal system. We find that computer programs or simulators such as TOUGH-REACT, NUFT and GEOS provide a “window” for designers and managers to aid in diagnosing or predicting the system response between sometimes widely-spaced wellheads where information about the system’s state is obtained. Because of parametric errors and uncertainty in parameter values that

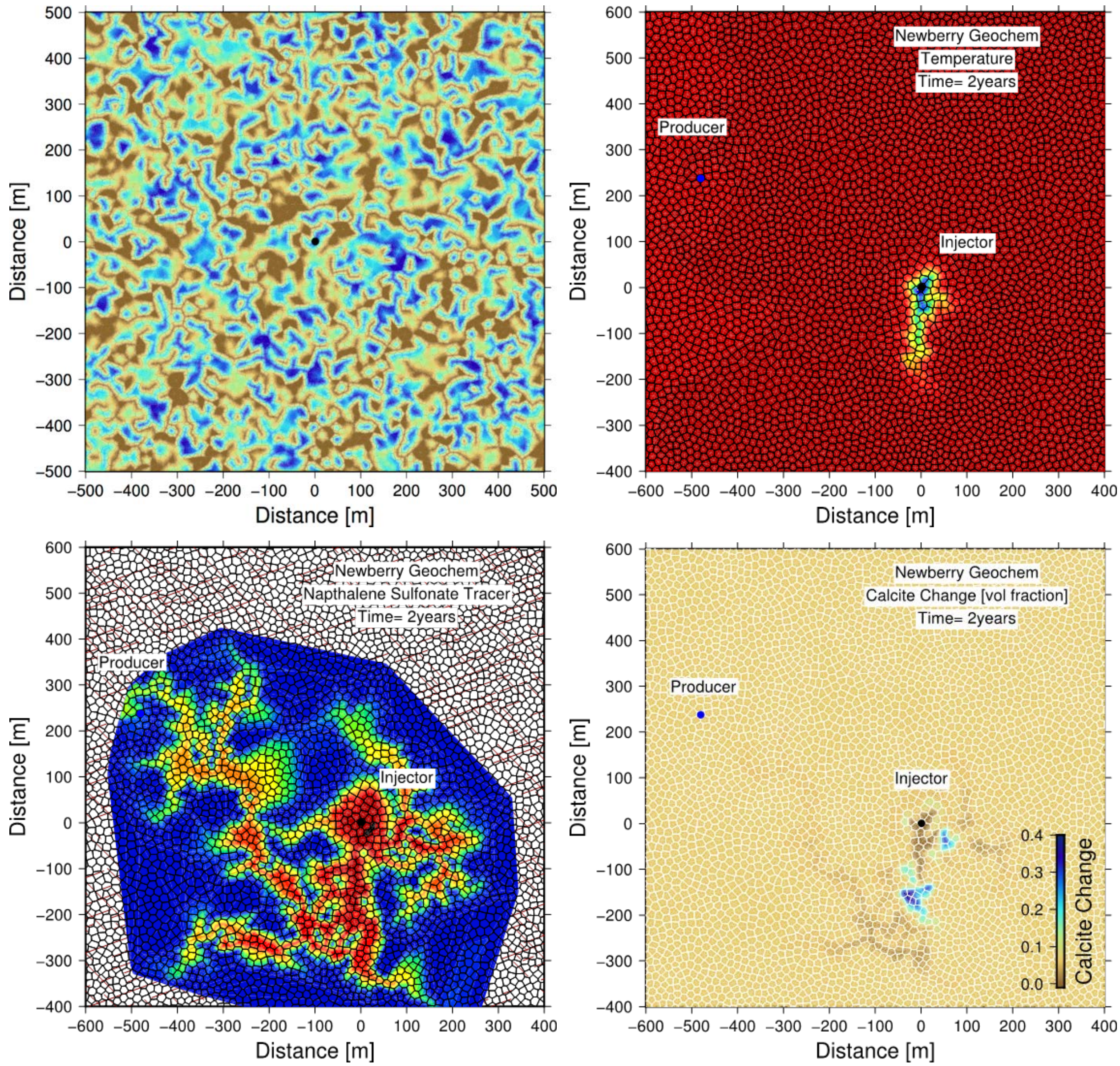

Figure 18 - Plan view of 2-D THMC model of a geothermal reservoir after injection/production (80 kg/s) over 2 years. Initial permeability field (upper left), temperature field (upper right), tracer distribution (lower left), regions of calcite dissolution (dark brown) and precipitation (blue) (lower right). Colors in the other plots are relative to the maximum and minimum values and are meant to be illustrative of the changes.

define the system, we suggest that uncertain simulation results should be viewed probabilistically. There are tools available (e.g., LLNL's PSUADE for uncertainty quantification) that currently allow us to take this approach. Finally, we are approaching the capability of modeling the complex nature of THMC and propose that solutions to some of the challenges, such as flow channeling (THM) in an EGS fracture network, may be found in manipulating other aspects of THMC, such as mineral precipitation (THC) to offset the growing fracture aperture. In addition, new research is beginning to focus on how formation permeability can be selectively modified by other approaches to give geothermal operators the control they need to extend production life. With the aid of simulators, uncertainty quantification tools, geothermal flow tracers and other methods of geothermal system characterization, we anticipate significant progress will be achieved towards the predictive and diagnostic quantification of THMC processes during the next decade that will support EGS/hydrothermal operational decisions as well as the development of new methods for extending the lifetimes of producing systems.

5.2. Geopressured Resources

5.2.1. Overview

The DOE report, *A History of Geothermal Energy Research and Development in the United States* (Kennedy, et al. 2010), defines geopressured-geothermal reservoirs as subsurface reservoirs that contain hot pressurized brine saturated with dissolved methane at the pressure, temperature, and salinity of the reservoir formation. Geopressured reservoirs can potentially provide three sources of energy: 1) chemical energy in the form of dissolved methane, 2) thermal energy from the hot brines (temperature over 93°C [200°F]), and 3) mechanical energy from high brine flow rates (over 20,000 barrels per day) and high well head pressures.

Although, geopressured reservoirs might occur in several areas of the U.S. (Wallace, et al. 1979; Strongin 1980, 1981), programs to evaluate and test geopressured resources have focused on the Gulf Coast region, where the extent and basic characteristics of geopressured reservoirs is well known from petroleum exploration and production activities (Kennedy et al. 2010) and the estimated recoverable reserves are large (Wallace et al. 1979).

Production wells tapping geopressured reservoirs flow at sufficiently high rates and pressures can directly drive turbines connected to electric generators. Methane that comes out of solution is expanded to drive the turbines and then be captured to be either be sold or used in a hybrid system to generate additional electricity. Brines produced from geopressured reservoirs in the Gulf of Mexico basin are not hot enough to directly flash water to steam to drive a turbine (Bassiouni 1980) but are hot enough to drive a binary cycle plant. The processed brine, now cooler, depleted of dissolved methane, and at lower fluid pressure, can then be disposed by injection into subsurface reservoirs.

The DOE's Geopressured-Geothermal Energy Program investigated geopressured reservoirs in Louisiana and Texas from 1976 to 1992. The total budget over this time was about $194 million dollars (Kennedy et al. 2010). The program tested 11 existing petroleum wells (Wells of Opportunity) that were converted into test wells. Five additional wells were designed and drilled specifically to evaluate the feasibility of long-term production from geopressured reservoirs. In addition, a 1 MW demonstration plant was developed to produce power from the Pleasant Bayou 2 designed well. The Pleasant Bayou plant went online in October 1989 and operated until May 1990 when it was shut down because the injection well required expensive reworking (Mines 2010).

Sanyal and Butler (2010) estimated the initial electric power that could be produced from the Pleasant Bayou demonstration well assuming a flow rate of 20,000 barrels per day to be 3.89 MW. Of this total, the thermal energy of the brine provides 37 percent, methane provides 49 percent, and the mechanical energy (pressure) provides 14 percent. Although the pressure of the brine provided a relatively small percentage of the power generated, it also contributed to the net power generated by lifting the brine to the surface, thereby eliminating the need to consume power to pump the brine. A simple calculation using the bottom-hole and well-head pressures, average production rates, and reservoir depths for the three DOE test wells suggest that this saves approximately 1MW per well.

At the time of the research program, prevailing economic conditions limited the continued development of geopressured-geothermal reservoirs. However, the program laid the foundation for all aspects of future development of this extensive resource (Kennedy et al. 2010). The significant accomplishments of the Geopressured-Geothermal Energy program include (Kennedy et al. 2010):

- Identified geopressured-geothermal onshore fairways in Louisiana and Texas (which comprise the vast majority of this resource in the US)
- Determined that high brine flow rates (20,000 to 40,000 barrels per day) could be sustained for long periods of time using appropriate scale inhibition protocols
- Brine, after gas extraction, could be successfully injected into shallower aquifers without affecting surface waters or subsurface fresh water aquifers
- No observable subsidence or microseismic activity was induced by subsurface withdrawal and injection of brine, and no detrimental environmental effects attributed to well testing were observed
- Corrosion, sanding and scaling could be controlled with chemical inhibitors and by reducing flow rates
- Demonstrated that the production of gas from saturated brines under pressure was viable
- A hybrid power generation system could be installed and operated

5.2.2. Geopressured Resources in the United States

The term geopressured has been used in the petroleum industry to mean subsurface fluid pressures that exceed hydrostatic pressure at their depth. Pressures approaching lithostatic (equal to the weight of the overlying rocks and sediments) have long been known to occur in the Gulf of Mexico and were an early focus of DOE investigations into Geopressured-Geothermal energy.

The two most recent surveys of occurrences of geopressured energy sources in the U.S. (Wallace et al. 1979; Strongin 1980) were performed independently. Wallace et al. (1979) note that the geopressured basins other than the Gulf of Mexico basin might contain viable geopressured-geothermal resources, but that the brines in these basins differ in temperature, methane content, pressure, and volume. In contrast to the Gulf of Mexico basin, these basins lack vertical loading by sediment deposition as the dominant mechanism for generating pressure. Vertical loading is the mechanism for generating large volumes of geopressured sedimentary rocks in the Gulf of Mexico basin. Strongin (1981) performed preliminary assessments of two other geopressured basins, parts of the Appalachian Basin in West Virginia, Kentucky, and Pennsylvania, and in the Great Valley region of California. Of these, California seemed to have the most potential as a geopressured-geothermal resource due to relatively shallow depths, high temperatures, low brine salinity, and potentially high levels of dissolved methane.

5.2.3. Resource Estimate

Wallace et al. (1979) updated a previous U.S. Geological Survey estimate of the geopressured-geothermal resources of the onshore and offshore portions of the northern Gulf of Mexico basin to a depth of 6.86 km. Assuming a conversion efficiency of 8 percent, the recoverable thermal energy could generate 23 to 240 GW of electricity. The range represents the extent to which the reservoir is de-pressured during the resource extraction. The lower value represents a controlled development in which pressure reduction is limited to prevent land subsidence. The estimated energy of the recoverable methane is 75-770 billion MWh (44-457 billion BOE), with the range again representing the degree of pressure reduction in the reservoir.

More recently, spatial analysis was used to update estimates of the total recoverable energy from geopressured reservoirs in Texas and Louisiana (Esposito and Augustine 2011, 2012). This work was an advance on previous estimation methods in that it used reservoir modeling to provide insight on geothermal brine and natural gas flow rate profiles over a long-term time frame, reservoir pressure and temperature changes with time, and potential recovery factors. These studies estimated the total recoverable electricity generation potential from the thermal energy to be about 5.1 GWe plus 1.25 × 10^{14} standard cubic feet of methane (35 billion MWh, or 21 billion BOE).

In comparing these two estimates of the geopressured-geothermal resources, it is necessary to consider that the Wallace et al. (1979) estimate includes both onshore and offshore reserves, while the Esposito and Augustine (2011, 2012) estimates includes only the onshore portion of the basin. Neither estimate includes the mechanical energy of the pressurized brine because previous studies indicate that it would contribute less than 1 percent of the total energy. However, as noted above, Sanyal and Butler (2010) estimate that mechanical energy could contribute 14 percent of the power generated at the Pleasant Bayou site.

5.2.4. Economics

Plum, et al. (1989) calculated the breakeven price for electric power generated from a geopressured-geothermal resource based on the results of field testing of three wells (Gladys McCall, Pleasant Bayou, and Hulin) from the DOE Geopressured-Geothermal Program. This study considered several scenarios to calculate a range of breakeven prices given different assumptions about production costs, reservoir properties, and the specific combinations of thermal, mechanical, methane energy extracted. Estimated breakeven prices, in 1990 dollars, were $0.13 to $0.27 per kWh. These prices were not competitive with conventional energy sources at that time.

In addition, the Plum et al. (1989) estimates of breakeven prices were calculated from a higher temperature reservoir in the Wilcox Formation in south Texas. Assuming the reservoir properties in this part of the Wilcox formation (not tested to date) are similar to those indicated by tests on the Hulin well, and conventional conversion technology is used, the estimated breakeven price is a more competitive $0.09 per kWh. This price estimate indicates the potential benefit of research to identify higher-quality resources. This study also highlighted projections of reservoir productivity and life as an important, but highly uncertain, input to the economic calculations. These analyses used operating lives of 5 or 10 years to represent what the authors thought was reasonable give the results of the well testing program.

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6. DISCUSSION

At the highest level, there are two hurdles that must be cleared before geothermal energy production can become a significant contributor to the US energy market; reducing costs and reducing uncertainty. The good news is that these objectives are not exclusive of each other and in fact are tightly connected through the technological advancements that will be needed to solve them. For example, developing high-temperature electronics that allow for monitoring while drilling (MWD) can reduce drilling costs by avoiding non-drilling time and by reducing uncertainty through better understanding and characterization of the system.

From a business value proposition point of view, the objective is to reduce risk, which is defined as the product of the consequence of an event and its probability of occurring (Figure 1). In geothermal energy development, the consequence is monetary and is primarily a function of the upfront capital costs of exploring and developing a site. The 'event' is developing a field that performs at or below a pre-determined level, such as the long-term breakeven point or an acceptable level of profit. Risk can be reduced in one of three ways: 1) reduce the consequence, 2) reduce the probability, or 3) reduce both. Understanding that reducing costs reduces the consequence and reducing uncertainty reduces the probability of underperforming, we can see that by clearing the technological hurdles of reducing costs and uncertainty that we are also reducing the risk of investment and development.

The largest costs of RM&D are drilling the production and injection wells and stimulation. Reducing those costs for a given drilling project is accomplished by doing them more quickly and/or by reducing material costs. During the planning stage, drilling costs can be reduced with better well siting and field management by developing improved subsurface characterization and data, modeling, and analysis (DMA) tools. Potential cost reductions during the process of drilling are reflected in the drill cost curves discussed above (Figure 6). Depending on the depth, the cost savings between the Ideal scenario and the Baseline scenario ranged from 50% at shallower depths to 75% at deeper depths. What is evident is that there still remains tremendous opportunities to reduce drilling costs within both the process of drilling and in better characterization and planning.

To get a sense of the sensitivity of drilling costs to reductions in time and/or material costs, Figure 19 shows the savings that halving the total drilling time and/or the material costs would have on the total drilling costs for the Baseline and Ideal scenarios (vertical, large diameter hole). Things like mobilization, de-mobilization, daily rig rental rates, site preparation, engineering, and logging fees are kept the same. This reflects data shown in Figure 7 and Figure 8 but shows the savings as a percentage of the non-adjusted scenario cost across all depths. For the Baseline scenario, the savings from halving the total drilling time is about 20% (red solid line) while for the Ideal scenario it is about 7% (red dashed line). The upside for reducing material costs is higher and is more dependent on depth due to the higher material requirements at depth. Halving material costs saves about 30-45% for the Baseline scenario (solid blue line) and 21-38% for the Ideal scenario (blue dashed line). By halving both the total drilling time and material costs the savings are 43-56% and 28-45% for the Baseline (solid green line) and Ideal (dashed green line) scenarios, respectively. As a point of comparison, the Ideal scenario drilling costs for this well configuration is equivalent to reducing the drilling time and material costs by 75% in the Baseline scenario. More importantly, what this shows is that game-changing improvements to drilling costs must include a reduction in material costs.

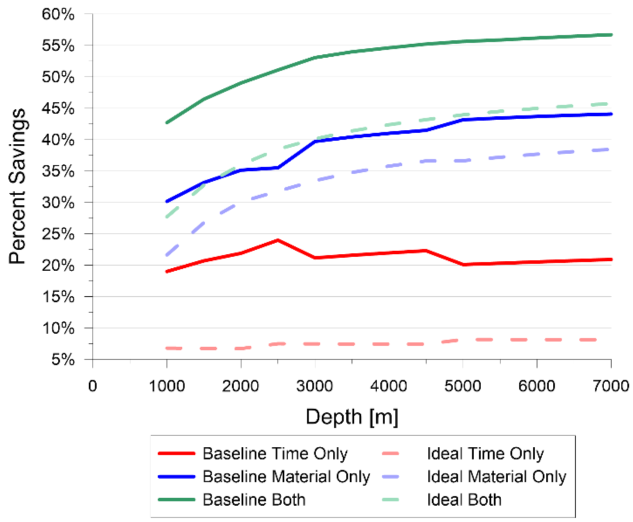

Figure 19 - Cost savings of halving drilling time, material costs, or both of a vertically oriented large diameter well for the Baseline and Ideal scenarios.

Material costs are comprised of costs for cement, casing, wellhead equipment, drill bits, bottom hole assemblies, and mud, with cement and casing accounting for 65-75% of the total material costs (Figure 7 and Figure 8). Because material costs are mainly driven by outside market forces, the only practical route for reducing material costs is through using less expensive materials, reducing the amount of material that is required, or by developing new, cheaper materials that can take the place of current materials.

Using less expensive materials is difficult since many of the materials such as casing and cement, must meet the significant load, temperature, corrosive, and pressure requirements found in geothermal wells; something that cannot be accomplished using low-grade materials. To this end, Ekasari and Marbun (2015) have shown some cost benefit through optimizing casing material based on the corrosive and pressure environment within a borehole to allow developers to use the least expensive grade allowable for their specific conditions. While this is definitely a good business practice, optimizing the use of currently available materials will only have a small effect on the total drilling costs.

Another technology that can aid in reducing material costs is the use of expandable casing (including folding casing technology). Used correctly, expandable casing has shown to reduce rig costs, the number of bits, and the volume of cement and casing (Teodoriu 2015) by eliminating one or more casing strings and/or allowing for the use of smaller bit diameters in the upper part of the hole. Expandable casing is gaining use in the O&G industry although it is used more as a means to mitigate problems and to extend holes than as a common drilling practice (Dupal, et al. 2001; Noel 2013).

The use of expandable casing reduces the need to telescope the borehole diameter with depth since strings of the same casing can be successively inserted into the hole below the lowest emplaced casing and then expanded to the appropriate size, opening the door to mono-bore drilling, which has been cited for the O&G industry as the next technological evolution of drilling (Teodoriu 2015). While the promise of expandable casing is high, it still suffers from reduced strength and higher costs than standard casing and still has issues in high-temperature, high-pressure environments (Gau, et al. 2015; Tao 2015).

The benefits of mono-bore drilling means that smaller diameter bits can be used in the upper parts of the hole, which reduces casing, cement, bit, and BHA costs as well as time costs associated with cementing, tripping, etc. To quantify this benefit, consider that for a 2500 m, large diameter, vertical well, 38% of the cost savings between the Ideal (which assumes a mono-bore design) and Baseline scenarios is from the mono-bore design, while the other differences (ROP, bit life, etc.) make up the other 62% of the savings. For a 5000 m deep well, the benefit of the mono-bore design increases, accounting for 78% of the difference between the two scenarios. Taken to the full extent, expandable casing can ultimately lead to cement-less drilling, which will reduce costs even further (Finger and

Blankenship 2010). It should be noted that these savings figures assume the expandable technology can be obtained and deployed at the same rate and cost as standard casing, which is currently not the case.

The use of expandable casing can also help with optimizing the production zone diameter to increase the productivity of the well. Looking at 43 producing wells in the Hengill area of Iceland, Sveinbjornsson and Thorhallsson (2014) show that on average the 29 large diameter holes (13 3/8" / 9 5/8" hole/liner) have a power output that is close to 40% higher than the 14 small diameter holes (9 5/8" / 7.0" hole/liner). The optimal diameter is a complex function of the well depth, length of the production interval, resource temperature, and reservoir geology. The use of expandable casing adds flexibility to the optimization by allowing drillers the ability to maintain larger diameters at deeper depths. Thus, development of expandable casing for geothermal drilling can have a significant impact on reducing the overall cost of drilling and increasing average well productivity.

While the technologies involved in drilling more quickly reduces both the time associated costs like labor and equipment rental, it can also reduce the material costs. For instance, increasing bit life reduces drilling time as well as material costs in the form of a lower total bit cost. Similarly, technologies developed for reducing material costs can also help reduce drilling time. Expandable casing technologies will reduce material costs as discussed above and the drilling time by reducing cementing and casing time and potentially drilling time if employed with casing while drilling (Finger and Blankenship 2010). This is yet another example of the complex interplay across cost categories and cost efficiencies that can have multiple benefits.

While Figure 19 shows the relevant material cost savings from the various time reductions, it only reflects the costs for a single well drilled in isolation and does not reflect the increased efficiency and the time value of money associated with developing an entire field. The implication of this is important. If we assume a per well power generation of 7 MW (the median value from Sanyal and Morrow 2012) and a production to injection well ratio of 2:1, it would take 11 wells to develop a 50 MW field (4 injectors and 7 producers). Using the average daily penetration rate of 77 and 226 m/day at 4000 m for the Baseline and Ideal scenarios (vertical orientation, large diameter) respectively, and assuming the availability of a single drilling rig, it would take about 1 year and 7 months to develop the field using the Baseline technology and just 6.5 months with the Ideal technology. In other words, the field is developed in about one-third of the time using the Ideal scenario technology, which is time that the power plant can be online and the field can be generating revenue for the developer. What this indicates is that the value of drilling time-saving technologies is far reaching and must be assessed at the project scale as opposed to the an individual well.

One of the most important categories of technology development for reducing drilling costs concerns downhole equipment that can withstand geothermal drilling environments. Without this capability, most of the technologies that address the reduction of material costs and drilling time will either be unable to be implemented in the geothermal environment, or will be less reliable if they are implemented. While some of these technologies exist, especially for temperatures below 200 ^{o}C, there are still issues with reliability and longevity as one passes that threshold. In addition, the costs of these component are usually much higher than their non-high temperature counterpart. The downhole components that are most vulnerable control power storage, regulation, and conversion, motor drives, data acquisition, data storage, monitoring, and pumps but due to the integrated nature of these systems a single system solution does not exist that can create a step change in capability and thus technology development in this area must be approached and evaluated as a whole-systems engineering problem (Norman 2006; Sisler et al. 2015; Watson and Castro 2015). Enabling this technology allows for better monitoring and logging while drilling which in turn allows for better well control and a reduction in NPT and drilling time. It also improves the ability to characterize the downhole geologic conditions (stress field, fracture network, etc.) and the ability to steer a borehole to align with the fracture or stress field. Thus, the development of affordable electronics and equipment that can withstand the extreme downhole geothermal drilling environments should be a research priority for the DOE and the rest of the geothermal community.

Besides technology improvements, significant improvements for RM&D can be obtained through better data, modeling, and analysis (DMA) tools. The characterization and maintenance of a geothermal reservoir is dependent on large sets of data that are either directly measured at a single point (i.e., within a borehole) or remotely sensed across a broad area (e.g., seismic monitoring, MT, etc.). This requires data processing and interpretation methods that can reliably convert these data into three-dimensional geologic models of the system that reflect the key operating metrics for geothermal energy production such as the stress field and the fracture network. Improving data analysis capabilities will allow for better reservoir characterization, increased drilling efficiency, more effective stimulation programs, and better long-term maintenance of the system. Highly capable analysis tools exist within the O&G and mining industries but their application to geothermal environments is limited and their usefulness across the scale of a geothermal reservoir has yet to be determined. The development and use of these types of tools for geothermal applications will have a significant impact. The play fairway analysis program funded by the DOE (DOE 2017) is addressing this issue at the exploration phase but more work needs to be done with respect to verifying these tools against known field data across a broader range of geothermal environments for RM&D.

Numerical modeling is used in all phases of geothermal energy development including exploration, characterization, planning, managing, and closure. There are three general types of numerical modeling tools required in geothermal; geologic modeling, THMC modeling, and systems analysis modeling. Geologic modeling integrates the collected field data to form a three-dimensional representation of the target reservoir. They are almost always static models with no temporal dynamics and are the data supported 'backbone' of the conceptual model that is the working foundation for most RM&D activities. Geologic models can also serve as a three-dimensional 'repository' of the relevant sub-surface parameters that are used in the THMC and systems models. THMC modeling simulates changes in reservoir properties over time and are used to evaluate the long-term performance of the reservoir as well as for planning drilling and stimulation activities. Depending on the application, a THMC model can vary from highly-detailed and complex models to lumped-parameter flow and transport models to simple analytical models. Systems analysis models connect reservoir performance with the surface infrastructure to simulate the coupled-performance of the entire geologic and power generating system. They frequently include economic assessments and are used for system engineering and optimization, reservoir maintenance, and risk management. Systems models can also address the interaction with outside factors like grid connectivity, environmental impacts, and local and regional economic benefits.

The state of DMA with respect to geothermal development has advanced considerably over the last decade however there are two high level gaps that must still be addressed; computational efficiency and parameterization. Computational efficiency refers to the speed of execution of the model and is focused mainly on the THMC models. There are two approaches to reduce simulation times; decrease the model resolution and/or develop more efficient solvers. Decreasing model resolution requires a tradeoff between numerical accuracy and simulation time and thus research should focus on examining these tradeoffs across a range of geologic and operational conditions and modeling applications to determine when and why the model resolution can be refined or relaxed. White, et al. (2017) have already completed a foundational step in this direction but more needs to be done. Advanced numerical methods such as model linearization and finite-analytic hybrid methods should be developed and tested for specific application to geothermal problems. Both of these approaches have the potential to significantly cut simulation times while maintaining a high level of numerical accuracy (Lowry and Li 2005).

From a model development point of view, the ability to integrate and couple models from reservoir, to wellbore, to surface production equipment, to plant, and back to injection is critical in geothermal since the loop represents a dynamic system with constant feedback between the parts. The GT-Mod system dynamics model (Lowry et al. 2010) provides this capability at the systems level, but a more integrated platform that brings together all three model types should be developed that allows for data storage, multiple model simulation, analysis, and visualization. An approach for development would be to determine the set of systems and processes to be modeled, inventory the available models, develop models that are not available, and then integrate the suite of models within a single platform. While this is a steep hill to climb, the benefits to the industry will be significant and long lasting.

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7. TAKE AWAYS

The list below, grouped by subject area and in no particular order, reflect what we believe are the key take away messages from this work. The objective is to provide entry points for larger discussions that involve prioritizing and funding future research and development activities with the goal of advancing geothermal energy production. Despite the amount of time and thought that has gone into this work, we understand that the subject area of RM&D is extremely broad and encompasses a wide range of technologies and disciplines. Because of that, we are certain that some readers will disagree with some of the items in the list and/or think that the list is incomplete. We welcome any comments or suggestions.

- There are two high-level challenges that must be met to forward RM&D; reduce costs and reduce uncertainty.

  Reducing costs and reducing uncertainty reduces the risk of investment and development. By reducing costs, we are reducing the consequence of underperforming or failing and by reducing uncertainty we are reducing the probability of underperforming or failing.

- Drilling costs are the major contributor to the total costs of a geothermal project and provides the greatest potential for improvement.

  Drilling costs can be reduced in one of two ways; 1) reduce the time it takes to drill a well, and 2) reduce the material costs to drill a well. These objectives are integrated in that technologies that help reduce drilling time can also reduce material costs and vice versa.

  Material costs are the major cost factor for drilling wells and become more important the deeper one drills. Thus game-changing technologies must involve a focused effort to reduce material costs.

  Non-drilling time is a major contributor to field drilling costs and its reduction is also an opportunity for considerable improvement.

- When prioritizing R&D investment, improvements in any single technology must be assessed at the field or project scale and must consider its integration in the entire system.

  Small reductions in drilling time and material costs for a single well can have a major impact on the total time and costs to develop the field.

  Technologies like high-temperature electronics can have wider applications than their initial intended use. Because of this, their development should be a priority.

  The reduction in uncertainty must also be part of the assessment.

- The geothermal industry is being hurt by the lack of publically available data on drilling and drilling costs.

  This slows the learning curve and prevents the deployment of targeted research efforts that can provide the greatest benefit.

  The DOE-GTO should develop a platform where operators can share proprietary information with the incentive that the collective information is provided anonymously to the public. This should be administered through the DOE National Laboratory system, which has a long and successful history of protecting proprietary and classified information. The platform should be aligned with the European effort.

The incentive for sharing these types of data is the potential to reduce drilling costs faster than would otherwise be possible.

- Better data, modeling, and analysis (DMA) tools are required at all phases of geothermal energy development.

  Geothermal reservoirs are controlled by THMC processes. Better understanding of these processes and better modeling tools are needed to avoid their deleterious effects and to potentially control their effects for better performance (e.g., use chemical precipitation to offset thermal expansion).

  THMC modeling improvements should focus on more accurate algorithms for THM and THC process integration, improved gridding techniques, improving computational efficiency, and parameterization (i.e. how to represent the reservoir in a numerical model).

  Developing integrated systems models that are capable of simulating complex field scale dynamics of the entire surface and sub-surface system, including economics will greatly advance our ability to conduct full system performance assessment and optimization. This will enhance RM&D as well as provide a mechanism for assessing technology advancements at the project level.

  Tools that provide rigorous and meaningful treatment of uncertainty are needed.

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