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Geothermal Drilling: A Baseline Study of Nonproductive Time Related to Lost Circulation

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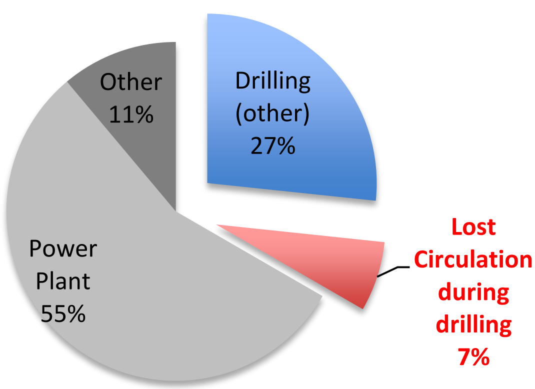
ABSTRACT

A single production geothermal well costs up to $7 million and a typical geothermal field contains 10 to 20 wells for a development cost of potentially $140 million according to a Geothermal Resources Group study. Capital cost coupled with exploration and resource uncertainty lead to high upfront project risk. This study analyzed the time and cost of detailed geothermal drilling operations. We found that the largest cause of nonproductive time in geothermal wells is advancing through lost-circulation zones, where drilling fluid is lost from the well. Mitigation measures implemented during lost-circulation events can increase drilling time by a significant fraction of the drilling days. The opportunity exists to reduce the drilling costs by addressing logistical inefficiencies and ineffective mitigation measures to minimize nonproductive time. This study reviewed daily drilling data for 38 geothermal wells drilled since 2009 in the United States. Our analysis summarizes the lost-circulation events identified in the available drilling data by assessing time per event, costs incurred, materials used, success of mitigation strategies, and resolution time. This study found that wells averaged over 100 hours of unprogrammed nonproductive time due to lost circulation, adding rig costs of an estimated $185,000 or more to each well. We present a plan for future research aimed at reducing lost-circulation nonproductive time and cost.

1. INTRODUCTION

Exploration, permitting, and drilling costs comprise about one-third of the capital for an average 50-megawatt (MW) geothermal plant, as shown in Figure 1. Drilling each well can cost up to $7 million, and fields typically contain 10–20 wells (Sanyal, 2011). These high upfront capital costs coupled with exploration and resource uncertainty lead to high upfront project risk. Reducing drilling costs can mitigate this risk. One way to reduce drilling costs is to reduce the significant unprogrammed nonproductive time (UNPT) that often occurs in geothermal well drilling, which can increase drilling costs by 20% or more.



Single well drilling cost:	USD $1-7 Million
Lost circulation drilling cost component:	~ 20%
Lost circulation cost:	USD $200,000-$1.4M
Wells per field:	10-20
Total drilling cost per field:	USD $10M-140M
Lost circulation cost per field:	**USD $2M-28M**

Figure 1: Breakdown of capital cost for an average 50-MW geothermal plant (IFC, 2013).

The oil and gas industry has made increases in rate of penetration; however, geothermal drilling penetration rates remain slower. Figure 1 compares depth versus days for best-in-class geothermal and oil wells in a Colorado School of Mines study (Tilley et al., 2015). This baseline study collects geothermal drilling data to analyze one of the primary obstacles to improved geothermal rate of penetration (ROP)—namely, mitigating lost circulation (LC). The high-temperature and high-pressure conditions of geothermal environments provide additional challenges to solving LC and wellbore integrity issues. Reducing ROP can have significant financial impact, and it is a topic that is broader than the scope of this study. Our study focused on identifying inefficiencies, nonproductive time (NPT), and ways to mitigate these events. As the analysis progressed, we focused more specifically on LC events, because this was identified as the largest cause of inefficiencies and UNPT.

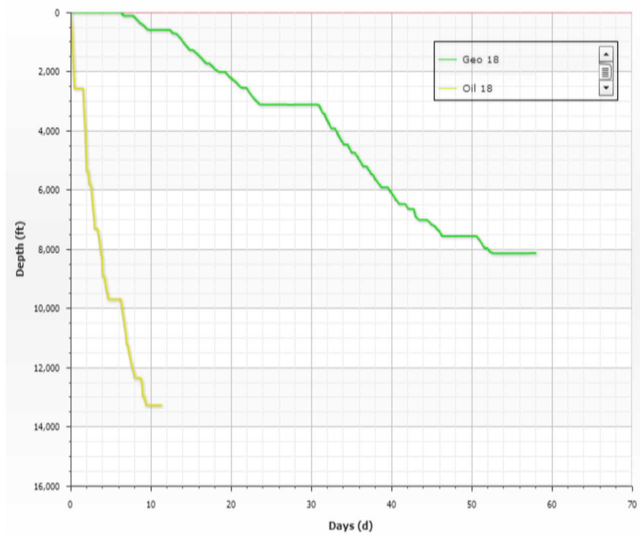


Figure 2: Days versus depth chart for best-in-class geothermal (green) and oil (yellow) wells in a small study conducted by Colorado School of Mines (Tilley et al., 2015)

2. BACKGROUND

2.1 Lost Circulation

Modern drilling methods rely on drilling fluid, or mud,[1] to lubricate the cutting surface, cool the bit, return cuttings to the surface, and maintain proper hydrostatic pressure against the formation. In geothermal wells, drilling mud is typically used above reservoir formations, which are then cased. Once steam begins to enter the wellbore, drillers typically drill pneumatically (i.e., with air) rather than with fluid, which reduces bit life and slows drilling (Rickard, 2016).

In areas above the reservoir where drilling fluids are used, this fluid may be lost in fractured, cavernous, or high-permeability formations; this is known as “lost circulation” or “lost returns.” When a portion of the mud pumped down hole is returned to the surface, losses are said to be partial. The industry defines losses of less than 25 barrels per hour (BPH) as “seepage,” losses of 25 to 100 BPH as “partial,” and losses of more than 100 BPH as “severe.” When no mud returns to the surface through the annulus, losses are said to be “total.” Typically, drilling cannot continue through total losses unless near the next casing point. If only 50 feet of depth must be attained before the next casing string is to be run, drilling will often continue while continuing to pump drilling fluids, even though the fluid will not return. The challenge is that there is no hydrostatic pressure control and cuttings are transported to an unknown downhole location. This acceptable length varies by driller and well. Circulation may also be lost through significantly overbalanced drilling (OBD). This is when the pressure of the drilling fluid in the wellbore (annular pressure) significantly exceeds the formation fluid pressure, causing fluid to be pushed into the formation (Savari, 2014). For this reason, mud characteristics (e.g., density, viscosity) must be closely monitored and adjusted as formation pressure changes (Clapper, 2011).

When circulation losses are encountered, drillers have used several responsive actions. Primarily, the driller focuses on maintaining downhole pressure by continuing to pump fluid down the hole. If this is unsuccessful and the annular pressure drops below the formation pressure, a “kick” could occur, where formation fluid enters the wellbore uncontrollably. If left uncorrected, a kick may lead to a dangerous blowout.[2] Other actions include attempting to seal the LC zone or altering mud parameters to drill underbalanced. Underbalanced drilling is using a mud weight lower than formation pressure to minimize the risk of fracture propagation and circulation loss. Although this may tend to decreases ROP, this technique saves time if used in appropriate situations.

2.2 Importance of Lost-Circulation Mitigation Success in Geothermal Drilling

Two important distinctions between geothermal drilling and oil and gas drilling relevant to the LC discussion are the difference in formations begin drilled and the completion of the wells. First, oil and gas wells are typically drilled in sedimentary rocks where lost circulation can be mitigated more easily than in the cavernous hard rocks typical of geothermal systems. Second, oil and gas wells are typically only cemented in the top and bottom portions of the well, and produce through tubing rather than the well casing. Therefore, the zones of lost circulation encountered while drilling do not need to be cemented during well construction. Drilling through LC zones can be done without later ramifications.

Geothermal wells, however, are cemented the entire length of the well because the hot geothermal fluids will heat the casing during production. If only the top and bottom portions of a geothermal well were cemented, the hot production fluids could cause the middle section of the casing to expand and buckle. Alternatively, if mud is trapped in the annulus, it too could heat and expand, causing the

[1] Drilling mud is a slurry of solids and liquids in a base liquid (typically fresh water).

[2] A blowout is the uncontrolled flow of fluids from the formation up the annulus to the surface. A blowout occurs when formation pressure exceeds the pressure applied to it by the column of drilling fluids in the wellbore.

internal casing to collapse. Thus, to prevent casing failure during production, geothermal wells are typically cased for the entire length of the well.

Therefore, addressing LC events during geothermal drilling becomes much more important than in oil and gas drilling. Trying to cement a well with LC zones becomes difficult because cement will be lost in these zones. Rather than completing cement jobs through the bottom shoe, drillers may have to resort to "top jobs"—placing cement from the top down—and/or perforating the well and squeezing cement into the annulus through the wellbore to fill open zones. Both of these methods add cost and are less successful at completing a solid cement job than the traditional bottom-hole cementing method. Addressing LC during geothermal drilling becomes critical to reducing the cost of well construction and cementing and to increasing the integrity of the well.

2.3 Lost-Circulation Mitigation

To solve partial losses, LC material (LCM) may be mixed into the circulating drilling fluid. The purpose of LCM is to block pores and fractures in the formation, sealing the wellbore and preventing fluids from flowing into the formation. For this purpose, LC materials often contain platelets, fibers, or polymers (Brandl, 2011). LCMs are relatively inexpensive and can be circulated and applied quickly (in under an hour). Wells analyzed for this study used paper, cottonseed hulls, nutshells, and calcium carbonate among other materials as LCM. These materials were used in 87% of the wells studied in this analysis.

LCM may also be mixed into the mud as a preventative measure if a fractured or highly permeable formation is predicted. This technique, known as wellbore strengthening, can prevent or reduce losses while drilling and allows a wider range of mud weights. Wellbore strengthening techniques were used in 8 of 15 wells in this study (53%). While drilling, mud weight must remain in a particular "window"—above the pore pressure and below the fracture pressure. If the mud weight dips below the pore pressure, the driller risks a kick, where formation fluid flows into the wellbore. Conversely, if the mud weight is above the fracture pressure, known as overbalanced drilling, the hydrostatic pressure of the formation is not high enough to prevent fluid infiltration and circulation losses (Savari, 2014). This makes a window of acceptable mud weights, which fluctuates with factors related to depth as shown in Figure 2.

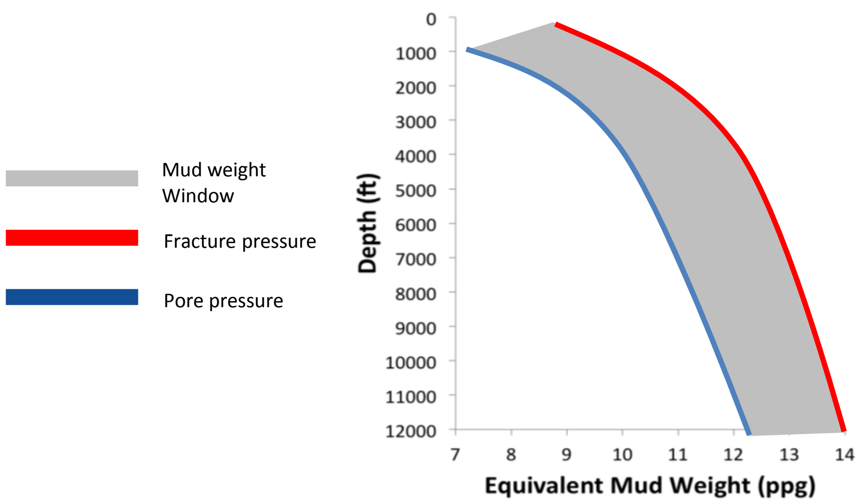


Figure 2: Example of a window of mud weight for a typical well. Mud weight must be maintained between pore and fracture pressures.

The purpose of wellbore strengthening is to increase the fracture pressure of the formation, allowing for a greater range of mud weights and reducing the risk of fracture propagation (Tetteh-Fiagbor, 2011). However, wellbore strengthening allows higher mud weights to be used in zones of suspected fluid loss.

Alternatively, LCM "pills" are applicable for larger fractures or more severe losses. These pills, which consist of specialized LCM intended to expand once placed in a fractured zone, ideally result in bridged/sealed fractures within two hours of placement. Pills are not intended to be suspended material in the drilling fluid, but are spotted downhole through the drill string and then squeezed into a severe loss zone, where they must be allowed to expand and set. This technique was used in 60% of the wells studied in this analysis.

When the formation is cavernous rather than fractured, or when total losses are encountered, a more time-consuming cement plug is usually placed to mitigate losses. Balanced cement plugs are the most commonly placed type of plug. The balanced nature of the plug requires that calculations be made to assure that the cement level inside of the drill string is equal in height to that in the annulus. The drill string must be pulled from the hole and a cement-plug-specific bottom-hole assembly must be connected. Once set up, the drill string and bottom-hole assembly is tripped back into the hole and the cement plug is set across the LC zone until fluid levels are equal and hydrostatically balanced. The drill string is then slowly pulled out once more and the cement is allowed to set. This technique is shown in Figure 3. Once set, the plug is drilled through and wiped clean to prepare for further drilling. Plugs are usually in the range of 50 to 150 feet in length and take around 20 hours from the start of tripping out the drill string to the completion of drilling through the plug. If the formation causing losses is continuous beyond this length, cement plugs may be set consecutively (Guo, 2014), and this technique was used in 87% of the wells studied in this analysis.

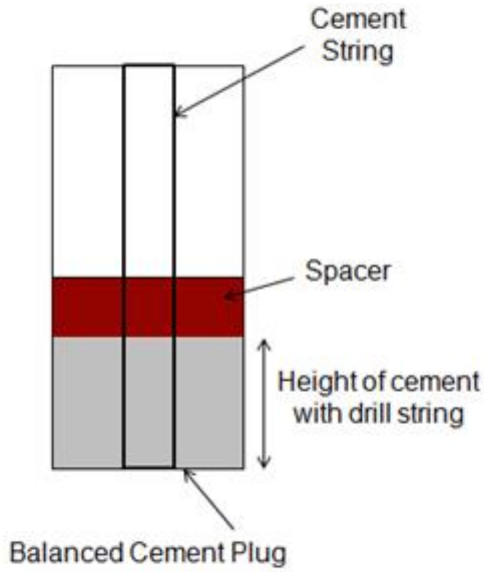


Figure 3: A balanced cement plug, where the height of the cement column outside the drill string (here called the cement string), is equal with the height of the cement column inside of the string ("Balanced Cement Plug," 2011).

The goal of LCM, pills, and cement plugs is to either reduce or mitigate LC while drilling. These strategies are typically employed for partial, severe, and total losses and are considered "successful" if losses are reduced to less than 25 BPH (i.e., if losses are reduced to seepage losses). If losses are initially only seepage, then success is considered mitigating all losses. If losses are initially minimal, drillers may try to "drill through" or mitigate using less-expensive LCMs. Drilling through the zone is possible because cuttings help to seal loss zones caused by pores or small fractures. If unsuccessful, or for severe or total losses, drillers will then typically use cement plugs. Generally, these mitigation methods are only seen in the surface and intermediate drill sections because circulation loss in the production zone is required. LCM, pills, and cement are rarely used below a depth of 8,000 feet.

2.4 Lost-Circulation Mitigation Success Rates

Success rates for the traditional methods of LCMs and cement plugs are low, with overall success around 25% in geothermal wells. In a study of 4,500 LC zones (Hyodo, 2000), LCM was used in 35% of cases and cement was used in 47%. Beyond a depth of 1,000 meters (3,281 ft), success rates drop to 7% due to the higher temperature and pressure conditions, causing traditional LCMs and cements to fail. When fluid losses were experienced, these losses were "total" about 65% of the time, indicating the complexity of fracture systems encountered in high-temperature, high-pressure geothermal drilling (Hyodo, 2000).

Failed LC methods can add significant wasted costs to the drilling process. As previously mentioned, mixing LCM in the drilling fluid typically takes 30 minutes to one hour, and cement plugs typically take about 20 hours. At an average onshore daily rig rate of $45,000, halting operations to execute a cement plug is clearly a serious commitment (Ahrenst, 2016). In this study, we look at overall NPT in a sample of wells—and, more specifically, LC frequency and success of LC cures. Ultimately, we find inefficiencies in the drilling process and formulate process improvements. Specifically, we analyze LC mitigation techniques, as well as discuss an idea for potential time and cost savings.

3. METHODOLOGY

3.1 Data Collection

We collected and analyzed data from 38 geothermal wells drilled since 2009 for our analysis. Fifteen of those wells are located in The Geysers geothermal area in California. Data were collected online through California's Division of Oil, Gas, and Geothermal Resources (DOGGR). These 15 recent wells were chosen due to their thorough logs. DOGGR data included daily drilling logs, fluid-loss information, cement details, directional surveys, permitting forms, bit information, drilling parameters, and mud logs for all wells (Table 1). Additionally, the U.S. Navy Geothermal Program shared data for seven of their recently drilled wells. These wells are located in two different fields, located at the Fallon Naval Air Station and in Imperial County, California. The U.S. Navy Geothermal Program data included daily drilling logs, cement details, directional surveys, bit information, and drilling parameters. The remaining 16 wells were shared by the Colorado School of Mines (CSM) Petroleum Engineering Department and included daily drilling logs and cumulative LC statistics. Additional geothermal well drilling data were examined, e.g., from the Nevada Division of Minerals (NDOM) and from the U.S. Bureau of Land Management (BLM), but these data sets were not detailed enough to be used in this analysis. The data types provided from each source are shown in Table 1. Table 2 in Appendix A lists each well with critical statistics such as total drilling days, total measured depth, year drilled, NPT percentage, and number of LC zones.

Table 1: Data Inventory for drilling data used in this study. We investigated four sources of data, but found that sufficient data for analysis were only available from the California DOGGR. Future studies would benefit from additional well data sets.

Data Source	# of Wells	Date Range	Location	Available Data				
				Daily Drilling	Mud Log	Mud Details	Drill Bit	Lost Circulation
DOGGR	15	2010–2015	CA	x	x	x	x	x
Navy	7	2010–2014	CA, NV	x		x	x	
CSM	16	2009–2014	–	x				x
NDOM	0	2009–2011	NV		x			
TOTAL	**38**	**2009–2015**	–	–	–	–	–	–

It is standard for oil and gas drillers to capture, in real time, nearly all of the available data during drilling operations to identify all opportunities for improving efficiency. We did not find geothermal data of this sort for our study. Many of the data sets collected were disappointing in their lack of granularity, which was a significant impediment to our study. Although we are aware that at least some geothermal drillers collect this sort of data, it is not clear how commonplace this is in geothermal drilling, nor if these data were collected, but just not publically available, for the wells listed in Table 1.

3.2. Data Analysis

The first step in analyzing the well data was to categorize drilling time. The daily drilling reports contain activity codes or descriptions in varying time increments of 0.25 to 24 hours. Twenty-four distinct operation codes were used in total across all 38 wells, with codes categorized by their productivity. For the purpose of this study, NPT was defined as any activity that did not show progress in well depth—any code other than drilling. Conversely, productive time was a sum of the time periods for which actual drilling occurred. UNPT was defined as any responsive action or event that was not, or could not be, planned for ahead of time. This grouping of activities included events responding to unexpected LC, stuck drill pipe, wireline loss, cutting and slipping the drill line, rig repairs, waiting, or fishing for tools. Examples of these activity classifications on a depth versus days chart can be seen in Figure 4.

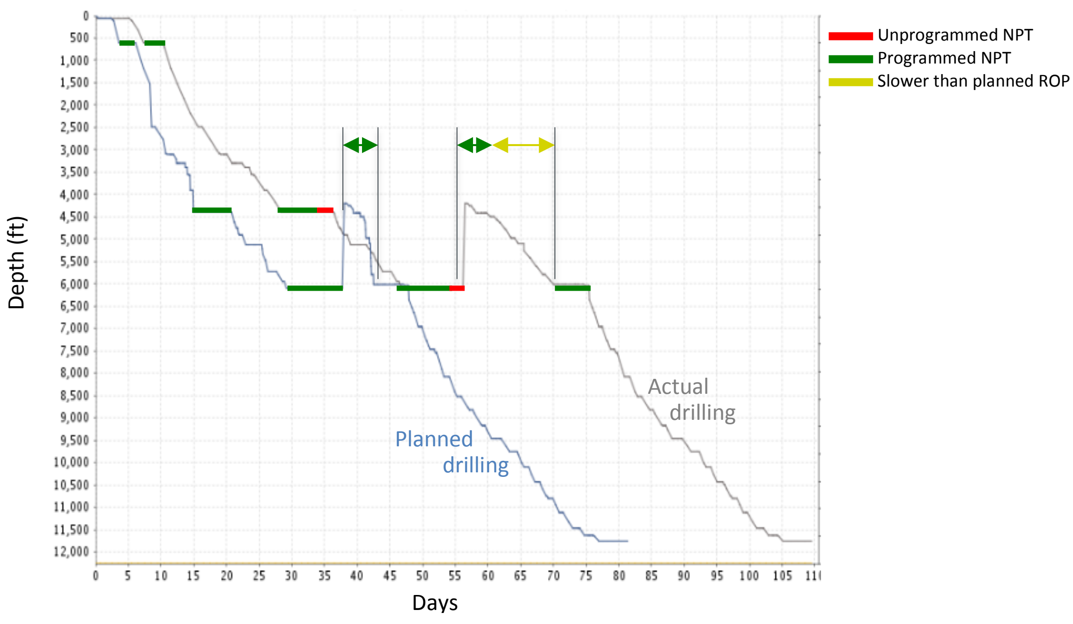


Figure 4: Sample of unprogrammed and programmed NPT and slower-than-planned ROP on a depth vs. days chart. The blue line shows planned drilling, and gray represents actual drilling.

Data provided were generally formatted as copied tables or PDFs, and thus, were first digitized and formatted. Data from all sources included depth, time of day, deviation, fluid loss, formation temperature, trip time, NPT, drill bit performance, LC cure success rate, cement cure time and waiting time, cumulative trip time, and rate of penetration. Once collected, digitized, and formatted, we developed figures to represent critical statistics for each well. Examples of the figures can be seen in Appendix A. Cumulative figures were made to compare data across wells and gather trending information. This study focused on reducing cost and time in the drilling process, and thus, it was directed toward NPT, especially that caused by LC events.

3.3. Down-Selection and Lost Circulation

After the initial analyses suggested that LC was one of the major issues, subsequent analyses focused on a better understanding of these events and subsequent mitigation. Circulation loss data were analyzed for the 15 DOGGR wells that provided appropriate LC information to see at what depths and in what formation environments LC events occurred. Figures were compared across wells to see what types of events related to longer drilling times and more NPT. These figures include representations for depth vs. drilling time, LC histograms, programmed versus trouble NPT, LC mitigation method success distribution and time consumption, NPT distribution, and waiting time per well.

Data were analyzed to find:

1. The probability and severity of LC events
2. The time required to mitigate LC events of each kind
3. Success rate and inefficiencies in mitigation methods

3.4. Geothermal Driller Interviews

Another aspect of this research involved contacting experienced drillers to get their opinion on the most important and pressing issues in geothermal drilling. Although several drillers were contacted with questions regarding drilling in general, NPT, LC, and LC mitigation techniques, we only interviewed two drillers. Future work may involve participation by additional drilling experts.

4. RESULTS

4.1 NPT Distribution

Areas of greatest potential improvement for all DOGGR and Navy wells are displayed in Figure 5, which is a Pareto chart of NPT. Note that in this chart, trip time includes all tripping in and out of the hole, not just specifically for LC mitigation or bit changes. However, this shows that there is opportunity to reduce trip time, and if each column is reduced, more efficiency may be attained per well. Activities classified as “other” vary widely by the drilling logger, but generally include activities such as setting up for other activities, picking up or laying down drill pipe, moving people or tools, waiting on daylight or weather, finding fluid level, or logging.

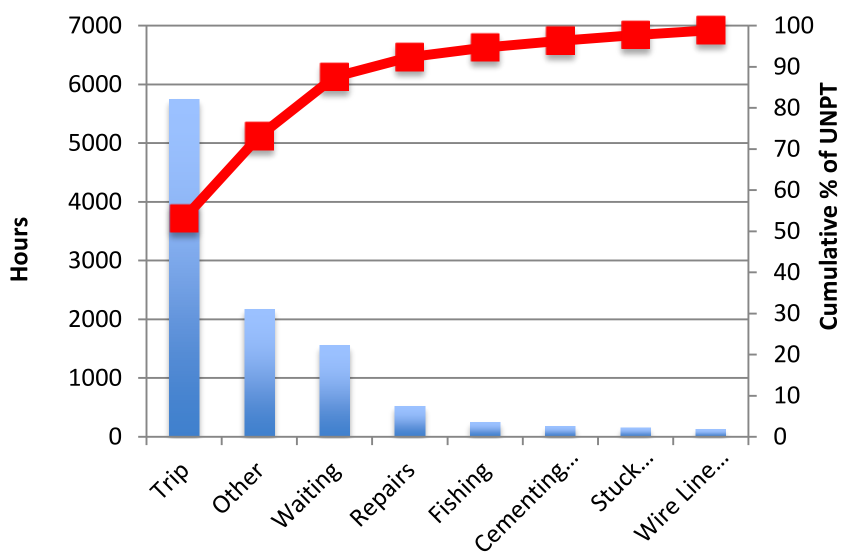


Figure 5: Pareto chart of NPT in all wells. Note that trip time includes all tripping in and out (e.g., bit changes, LC, casing) and may be reduced but not eliminated. “Other” includes activities such as movement of tools, taking measurements, or logging, although this varies among loggers and operations. Waiting time consists largely of waiting for cement plugs or casing cement to set.

Waiting time designated in Figure 5 includes waiting time during cement-plug operations, which is typically waiting for cement to set. This is a large factor in NPT because many of the attempted cement plugs failed to mitigate LC while drilling. Waiting for cement to set is perhaps the most easily reduced factor in NPT shown in this Pareto chart. Because it constitutes a large percentage of NPT, LC mitigation techniques are the focus for the remaining results.

4.2. Cumulative Trends

Across the 15 DOGGR wells that included LC remediation details, a total of 2,434 hours (101 days, 10 hours) were spent attempting to resolve LC in 211 LC events, with 1,734.5 of those hours spent on failed methods (71.3%). Cement-plug application time, from start to finish, averaged 20.15 hours. These data are summarized in Figure 6.

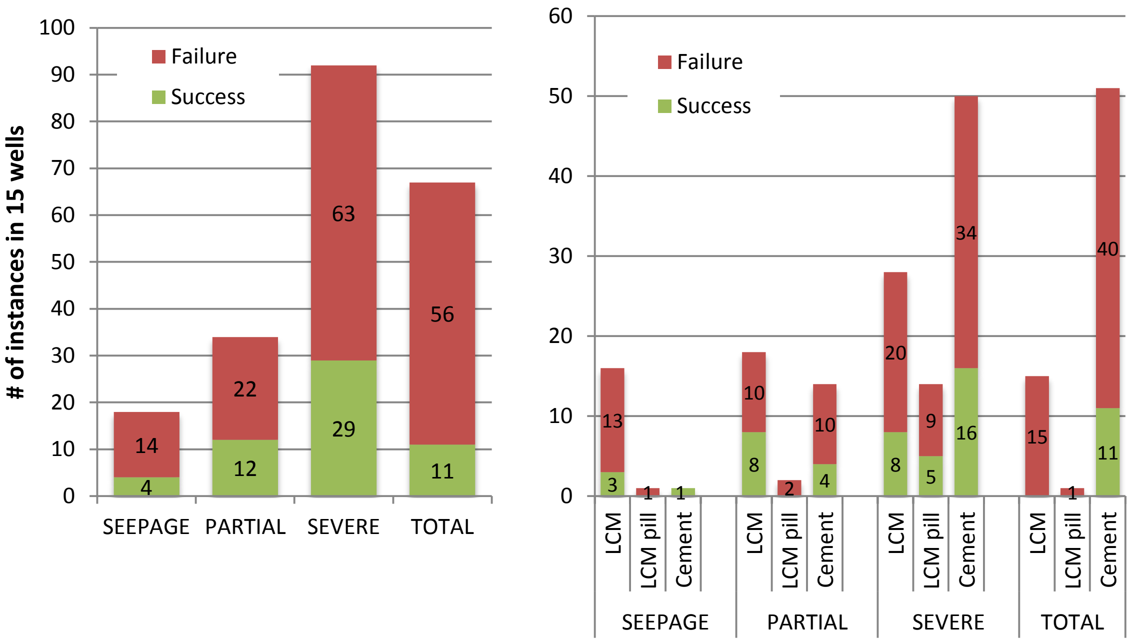


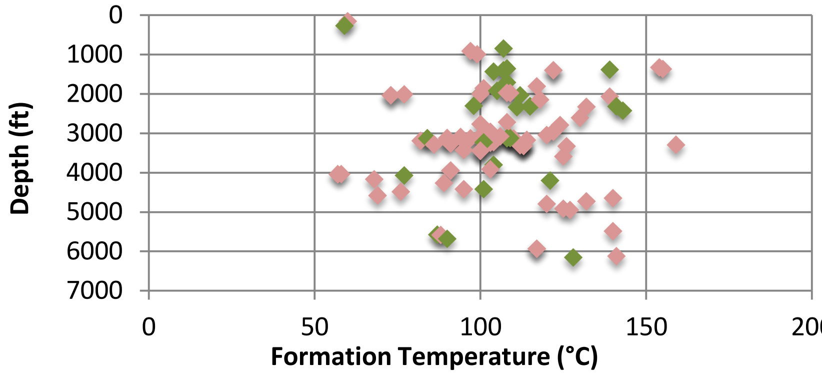
Figure 6: Success of LC remediation techniques by initial loss level. Numbers of failed applications are labeled on each column.

In Figure 6, attempts to mitigate LC are separated by initial loss level and the LC mitigation technique used. In the figure on the left, all methods are summed into cumulative success and failures. Success in mitigating losses for partial, severe, or total losses is defined as reducing losses to less than 25 BPH upon application. In general, failure rates were 77.8% for seepage, 64.7% for partial, 68.5% for severe, and 83.6% for total. For losses that begin as seepage, success is here defined as complete elimination of fluid losses. LC materials mixed into drilling fluid was the most common mitigation method for seepage losses (less than 25 BPH), and saw 3 successes and 13 failures (19% success), whereas LCM pills led to one failure and cement plugs tallied one success. For partial losses (25–100 BPH), mud-mixed LCM was still the most common technique and experienced a higher success-to-failure ratio of 8:10 (44% success). Two failed LCM pills were applied to partial losses, along with 10 failed and 4 successful cement plugs (29% success). For severe losses (greater than 100 BPH, but some returns), cement plugs were the most commonly used mitigation technique, with 34 failed and 16 successful applications (32% success). Mud-mixed LCM was successful in 8 of 28 attempts when applied in severe losses (29% success). LCM pills were successfully applied in 5 of 14 attempts (36% success). Cement plugs were the only mitigation method that saw success in total losses. LCM experienced 15 failures, and LCM pills had one failure. Cement plugs succeeded in mitigating losses in 11 of 51 attempts (22% success).

LCM and cement-plug success by depth and temperature for the 15 wells analyzed can be seen in Figures 7 and 8, respectively. Often these techniques were applied together. In many situations, if LC materials failed to regain circulation, then using a cement plug was the next step. Cement plugs were more commonly used for total or severe losses, whereas LCM was often applied preventatively or for minor losses.

Many factors affect the success of a cement plug including: temperature, pressure, plug base, density, length, cause of circulation loss, hydrostatic balancing, and contamination. Cement additives can include fibers, polymers, anti-settling agents, retarders, or foaming agents (Hudson, 2015). Variations in additives were not well recorded in the drilling logs in this data set, but may be a contributing factor in success rates. Figure 7 shows that cement-plug success was more common at depths of less than 3,000 feet. Of the 116 cement plugs attempted, 32 (27.6%) cured circulation losses to acceptable (seepage) levels. This indicates a cement-plug success rate that is slightly higher than LC materials, but the cement-plug process is more time-consuming and costly. Some 1,571.5 hours were spent setting failed cement plugs—an average of more than 100 hours per well. This is UNPT, because no progress was made in drilling depth. At an average rig rate[3] of USD $45,000 per day (Ahrenst, 2016), these 15 wells likely lost more than $2.8 million related to setting cement plugs that did not mitigate LC. This expense only accounts for the daily rig rate, not the cost of cement, tools, water, or other resources.

[3] Rig rates were estimated because actual costs for these wells are unknown.



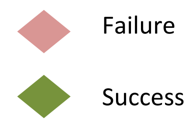


Figure 7: Cement-plug success by depth and temperature.

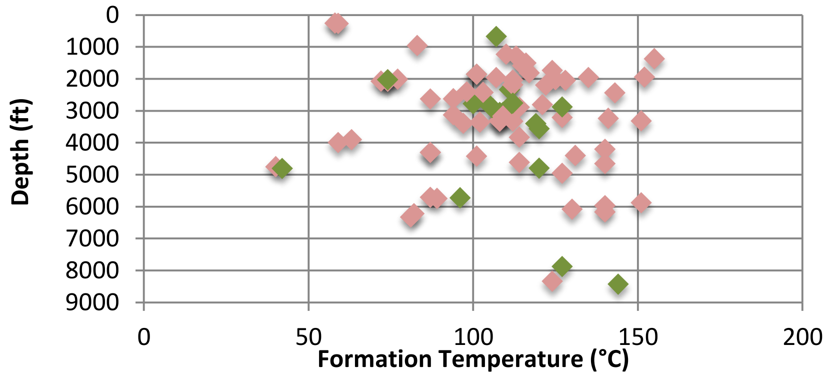


Figure 8: LC material success by depth and temperature.

LC materials did not show any apparent trends in success with depth or temperature (Figure 8). LC materials are often chosen by trial and error on a well-by-well basis. Interviews revealed that materials are not selected based on downhole environment. The severity of losses can give drillers an idea of which materials will work best based on past experiences. Some drillers have material preferences, but ultimately, materials available depend on investor and client choice (Rickard, 2016). In this study, 69 hours were spent applying failed LCMs across the 15 wells with appropriate data. Many of these instances were sweeps, which are LCM additions to mud meant to seal the wellbore and lift cuttings before losses occur.

4.3. Comparison of Wells

We looked at two specific wells, Wells 36 and 56, drilled in close proximity in the Wildhorse State Field in The Geysers Geothermal Area, California, to examine whether past experience helped to reduce drilling time and issues in drilling the second well. These two wells demonstrate LC time and its effect on drilling cost. Wells 36 and 56 are located 0.65 miles apart, and lithology logs show that they were drilled through nearly the same formations. Well 36 was drilled to a depth of 12,340 feet, ending 1/21/2010 after 102 days. Well 56 was drilled to a depth of 11,687 feet, ending 6/8/2010, only months after the first well was drilled. The drilling process for Well 56 totaled 129 days, because more LC events were encountered.

Both wells lost circulation in siliceous greywacke and argillite formations having similarly low porosity and permeability. The greywacke and argillite are similar to sandstone or mudstone, indicating that circulation was likely lost to natural or induced fractures. The greywacke in The Geysers naturally contains four types of matrix porosities: young fractures, vugs, voids, and veins (Gunderson, 1991). Fractures could have been induced by high annular pressure. LC plots for each well are in Figures 9 (Well 36) and 10 (Well 56).

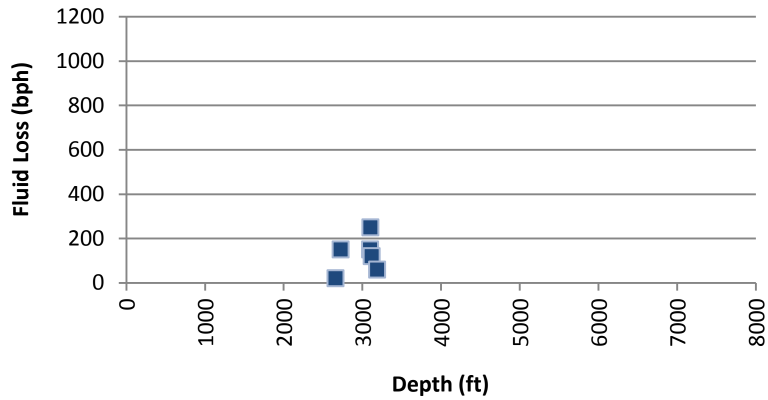


Figure 9: LC for Well 36, drilled in 102 days.

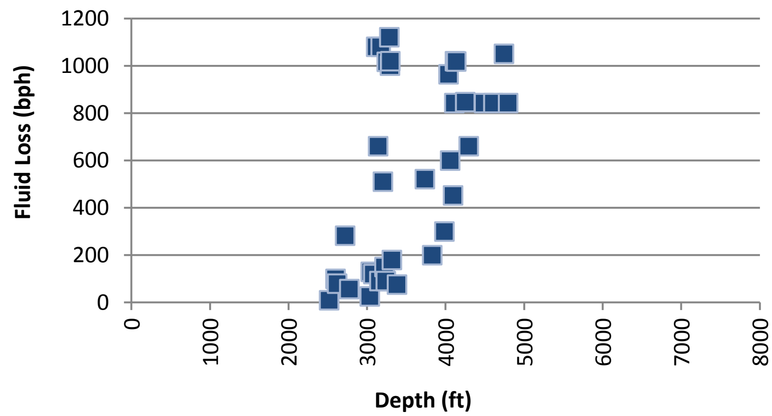


Figure 10: LC for Well 56, drilled in 129 days.

Because of severe losses and inability to mitigate losses while drilling, Well 56 took an additional 27 days. At an average rig rate of USD $45,000 per day (Ahrenst, 2016), the estimated additional cost of Well 56 was $1.22 million.

5. FUTURE RESEARCH

Experts interviewed stated that LC was the single-most unpredictable issue in geothermal drilling in 1977—and it still is today. Despite the low success rates of LC materials and cement plugs, they both continue to be common techniques in geothermal drilling. The petroleum industry has adopted many advanced techniques and materials to stop LC (Tilley et al., 2015). However, the high-pressure, high-temperature, fractured environments in geothermal drilling call for more robust materials and methods. With newly developed materials, it is often hard to field-test due to the low number of geothermal wells drilled annually, as well as risks associated with potential downhole damage or production loss.

5.1 Discussions with Industry

Experts shared that LC is a commonly encountered problem, but certain materials and methods allow efficient mitigation. Real-time data analysis is not often used, but data are analyzed after collection, especially for wells in the same field. Some experts cited that with the use of more-advanced materials—such as micronized cellulose, fibrous material—they experience upwards of 90% LC mitigation success; but those materials come at a cost of up to five times that of many other LCMs. Thus, it is sometimes difficult to convince investors and clients to use it. If clients were willing to spend the money on more-advanced materials, and if significantly higher success rates could be seen in mitigating LC, then savings would come in the form of drilling time and cost (Rickard, 2016). Future research could identify successful materials in select temperature, pressure, and geological environments.

5.2 Lost-Circulation Laboratory

To test LC materials and methods, researchers are looking to develop a lost-circulation laboratory to increase research and testing prior to use down hole. A laboratory for LCMs would need to include variable fluid chemistry, temperature, pressure, formation type, porosity, and permeability. Furthermore, LC environments would need to be simulated, such as caverns, vugs, and natural and induced fractures—all with variable sizes. With this approach, a matrix or spreadsheet could be created with recommended additives and materials to use in each environment. Similar studies have been conducted (Savari, 2014), showing which additives and combinations of LCM will work in select environments; but these studies have not included variations in pressure, temperature, and LC environment. By continuing this work, a database may be created for selecting LCM and cement composition by down-hole environment. Measurements of pressure, temperature, and cuttings should provide enough detail to drillers for selecting appropriate materials. This could increase LCM success rates and reduce NPT. The Colorado School of Mines has started to build such a laboratory for oil and gas operators.

5.3 Other Drilling Improvements

Wellbore integrity is a broad term that pertains to proper management of drilling parameters to allow for a safe and stable hole. During the drilling process, annular pressure, weight on bit, revolutions per minute, rotary torque, and mud characteristics must all be observed and managed. If drilling is executed properly, the wellbore will not only be more stable, but is likely to produce better. The oil and gas industry has adopted methods to manage these parameters in real time. This beneficial technology is sometimes seen in geothermal drilling, but it is not common (Tilley et al., 2015). Several other solutions for LC and NPT have been studied and published, most notably: underbalanced drilling, the use of polycrystalline diamond compact (PDC) bits, and casing while drilling. Some experts regularly implement underbalanced drilling to reduce risk of LC (Rickard, 2016). These techniques have been included in Figure 11, which provides an overview of drilling improvements and difficulty of implementation.

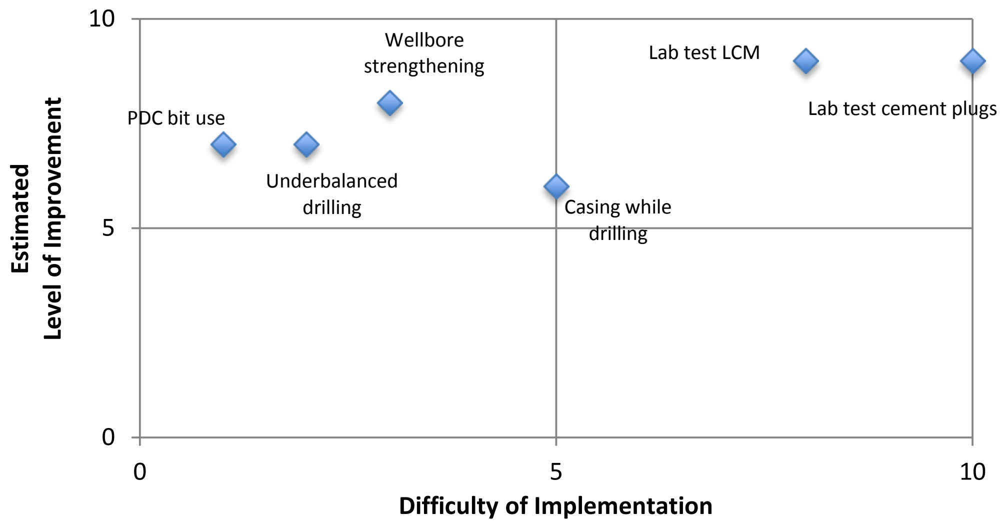


Figure 11: A visual representation of solutions by estimated difficulty of implementation (10 = most difficult) and estimated level of improvement (10 = most improvement).

6. CONCLUSION

Current hurdles to effective geothermal drilling operations are high costs combined with low success rates. Both factors are affected by NPT, especially that caused by LC. Lost circulation is complicated in geothermal environments due to the high-temperature, high-pressure, naturally fractured environments—even above the geothermal reservoir. The success rates of LC mitigation techniques in these data—24.7% for mud-mixed LC materials, 27.8% for LCM pills, and 27.6 % for cement plugs—give insight into the complexity of circulation loss. This suggests failure to mitigate LC occurs in three out of four tries. Even wells of the same depth and formations can experience wildly varying amounts of LC, resulting in unpredictable well cost. To advance the geothermal industry, strides must be made in mitigating LC in drilling. Advanced drill bits, underbalanced drilling, wellbore strengthening, and casing while drilling are all commercialized technologies with potential to reduce NPT caused by LC. Future research could be done to investigate the most successful materials for LCM and cement in all ranges of geothermal drilling environments. By testing these materials, a guide for selecting highly successful materials will help the geothermal industry mitigate LC quickly and efficiently. This outcome could lead to an increase in geothermal drilling success, shorter drilling time, and lower drilling cost, thereby helping to overcome current geothermal drilling hurdles.

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APPENDIX A

Table 2: All wells analyzed in this study, sorted by average penetration rate, a measure of drilling efficiency (largest [most efficient] first)

Well	Drilling Time	Depth	Year Drilled	NPT (includes all non-progressive time)	LC Zones	Drilling vs. Depth Efficiency Ranking	LC Cure Time/Ft	Average Depth Per Day
--	days	ft		%	# of zones		days/ft	ft
FDU2D	12	4,525	2012	56.3	-	1		377.1
88-24	22	5,020	2012	53.2	-	2		228.2
50	26	4,693	2015	64.3	31	3	0.00010654	180.5
61-36	39	7,021	2013	64.0	-	4		180.0
86-25	18	3,050	2014	73.6	-	5		169.4
HAD-1	21	3,020	2010	61.5	-	6		143.8
YUMA 17	21	3,020	2011	59.9	-	7		143.8
32	58	8,141	2011	62.7	5	8	0.00239528	140.4
88	58	8,141	2011	62.7	5	9	0.01592995	140.4
Geo 18	58	8,141			-	10	0.00374646	140.4
34	61	8,258	2012	61.3	1	11	0.00169532	135.4
Geo 23	52	7,000			-	12	0	134.6
Geo 19	64	8,258			-	13	0.00611528	129.0
32-28	28	3,493	2011	67.0	7	14	0.00744345	124.8
36	102	12,340	2010	65.7	6	15	0.01146677	121.0
Geo 20	102	12,340			-	16	0.01231766	121.0
Geo 25	58	6,983			-	17	0.00150365	120.4
NAFEC-3	30	3,520	2010	72.2	-	18		117.3
Geo 7	65	7,622			-	19	0.00137759	117.3
13	101	11,217	2014	51.7	53	20	0.00080235	111.1
Geo 24	55	6,069			-	21	0.00074147	110.3
22	86	9,205	2013	67.6	31	22	0.02504073	107.0
Geo 12	86	9,205			-	23	0.03796849	107.0
Geo 21	110	11,753			-	24	0.04233387	106.8
WHS 34	110	11,743	2010	56.1	28	25	0.00446694	106.8
33	32	3,111	2015	82.0	16	26	0.03841208	97.2
26	46	4,294	2011	65.6	30	27	0.03260363	93.3
Geo 14	46	4,294			-	28	0.05717279	93.3
Geo 11	91	8,425			-	29	0.00047477	92.6
Geo 8	128	11,687			-	30	0.08560794	91.3
71	110	9,976	2010	61.1	29	31	0.03573576	90.7
56	129	11,687	2010	70.2	33	32	0.06832377	90.6
Geo 9	110	9,882			-	33	0.07407407	89.8
Geo 22	73	6,295			-	34	0.03129467	86.2
Geo 1	155	10,825			-	35	0.06027713	69.8
Geo 2	46	3,080			-	36	0.03246753	67.0
87-28	59	3,080	2011	69.8	18	37	0.03961039	52.2
77-34	41	2,024	2015	82.3	37	38	0.10523715	49.4

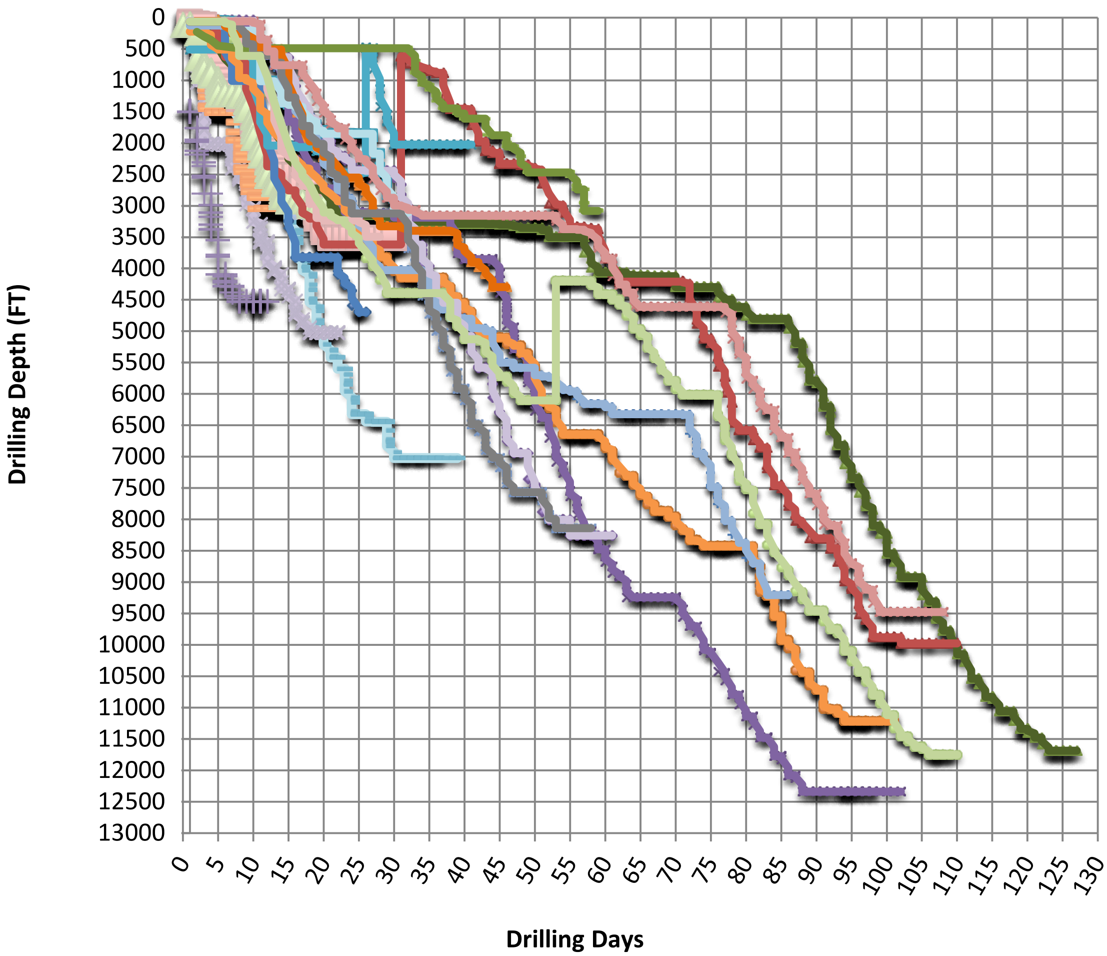

Figure 12: Depth versus days chart for 22 wells (CSM wells excluded). The most efficient wells are those that are the most vertical—drilling the most depth in the fewest days

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