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Downhole Sensors in Drilling Operations

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ABSTRACT

Before downhole and surface equipment became mainstream, drillers had little way of knowing where they were or the conditions of the well. Eventually, breakthroughs in technology such as Measurement While Drilling (MWD) devices and the Electronic Drilling Recorder system allowed for more accurate and increased data collection. More modern initiatives that approach drilling as manufacturing— such as Lean Drilling, Drilling the Limit, and revitalized Drilling the Limit programs—have allowed petroleum drilling operations to become more efficient in the design and creation of a well, increasing rates of penetration by more than 50%. Unfortunately, temperature and cost limitations of these tools have prevented geothermal operations from using this state-of-the-art equipment in most wells. Today, petroleum drilling operations can collect surface measurements on key drilling data such as rotary torque, hook load (for surface weight on bit), rotary speed, block height (for rate of penetration), mud pressure, pit volume, and pump strokes (for flowrates). They also can collect downhole measurements of azimuth, inclination, temperature, pressure, revolutions per minute, downhole torque on bit, downhole weight on bit, downhole vibration, and bending moment using an MWD device (although not necessarily in real time). These data can be used to calculate and minimize mechanical specific energy, which is the energy input required to remove a unit volume of rock. In geothermal operations, these data are not always used due to poor accuracy or lack of equipment. This is one of the major hurdles for geothermal well construction and a reason why geothermal drilling operations take much longer than their petroleum counterparts. This paper reviews the surface and downhole data collection equipment used in the petroleum industry and its associated costs, capabilities, limitations, and impacts. The impact these downhole tools and measurements have had on increasing drilling efficiency for the petroleum industry suggests that developing these tools for high-temperature, high-pressure environments could be similarly impactful for the geothermal industry.

1. INTRODUCTION

Sensors have been used to measure surface data while drilling since the late 1920s (Miller and Erdos, 2018). Data collected by these sensors were important because they provided vital information about the subsurface and the equipment being used. At the surface, traditional operational data measurements are collected, including drill-string measurements such as rotary torque, hook load, and the block height from which the rate of penetration (ROP) can be determined. Additional surface measurements can be made to get information about the drilling mud that is pumped downhole, including mud-flow volume, mud temperature, mud pressure, mud resistivity, gas readings, and pump strokes. In the late 1960s, the first Measurement While Drilling (MWD) equipment was developed, allowing for drillers to collect real-time data downhole (Starkey and Delashmutt, 2018). Logging While Drilling (LWD) equipment was developed in the 1980s to allow collection of gamma, density, porosity, and resistivity formation measurements (Anguiano-Rojas, 2014). Today, MWD equipment is able to provide near real-time measurements such as azimuth, inclination, temperature, pressure, revolutions per minute (RPM), downhole torque on bit (TOB), weight on bit (WOB), downhole vibration, and bending moment.

The existence of these downhole tools is common knowledge within the drilling industry. But it is also well understood that within the geothermal industry, these tools are not as commonly used because of harsh downhole conditions. For this analysis, we explore the types of downhole tools available, types of data collected, frequency of using these tools, impact of data collection on ROP, and limitations of this equipment for use in geothermal wells. The goal is to better understand the potential for improving ROP during geothermal drilling if these tools were to be developed for geothermal environments.

2. METHODOLGY

To appropriately address these questions, a thorough analysis—perhaps extending into the future—would collect and use statistically significant volumes of drilling data from the petroleum and geothermal industries. Due to time and budget constraints as well as lack of data access, we relied on literature surveys and interviews with drilling experts in both industries. We found information provided to us to be consistent among the experts and literature sources.

3. ANALYSIS AND RESULTS

3.1 Data Collection

Data collection methods for both surface and downhole measurements have improved dramatically over the last 50 years. Rig data such as rotary torque and speed, hook load, mud temperature, mud pressure, pit volume and pump strokes, and block height are now commonly monitored in real time and are easily available to the onsite and remote crews (Rickard, 2018). Downhole measurements have also improved significantly. The introduction of M/LWD technology has allowed for real-time downhole data collection. These M/LWD tools are more accurate than surface measurement tools, which have significant noise in the data. Table 1 summarizes the data collected. Today on both geothermal and petroleum rigs, it is standard to use electronic data recorders to collect and continuously record both direct and indirect measurements at the surface during the drilling process.

Table 1. Summary of types of data typically collected in surface and downhole tools.
Measurements taken in low-temperature (<150°C) drilling;
the most common measurements are indicated with an asterisk (*).

	Surface Data	Downhole Data
Mud Data	Pit volume Mud temperature Mud pressure Mud weight Pump strokes	N/A
Well Data	Temperature Pressure Gas measurements	Temperature* Pressure
Directional Data		Inclination* Azimuth*
Drilling Mechanics	RPM Weight on bit Torque Bending moment Rotary torque Hook load Rate of Penetration	RPM* Weight on bit Torque on bit Bending moment Downhole vibration*
Geological Data	Cuttings analysis	Density* Porosity* Resistivity* Gamma*

Collecting data downhole significantly increases measurement accuracy and can help improve drilling rates. However, downhole data collection is not common in geothermal drilling due to the temperature limitations of the tools.

Downhole LWD tools can provide measurements of geological data, which is very beneficial for locating hydrocarbon reservoirs in sedimentary aquifers, but which our experts suggested was less valuable for drilling through geothermal environments.

MWD tools, however, allow for measurements of well data such as bottom-hole temperature and pressure, directional, and drilling mechanics data, which have value in both petroleum and geothermal drilling. MWD tools collect different measurements, but we found that almost all MWD tools mounted on the bottom-hole assembly (BHA) will provide information on temperature, pressure, inclination, and azimuth, regardless of make or model.

Surface and downhole equipment are used extensively in the petroleum industry, but this is not the case for geothermal drilling operations. Regarding surface equipment, petroleum and geothermal drillers use similar equipment, but petroleum operations will use these data much more effectively to increase their ROP and reduce the Mechanical Specific Energy (MSE) required. Optimizing the MSE that is required while drilling results in an increased ROP (Rickard, 2018). MSE is the energy input required to remove a unit volume of rock, and it can be expressed mathematically in terms of controllable parameters such as WOB, TOB, ROP, and RPM. Minimizing MSE by optimizing controllable factors results in maximum ROP.

The petroleum experts interviewed suggested that downhole information such as temperature, azimuth, inclination, RPM, and downhole vibration are often considered standard or semi-standard in onshore operations (Figure 1). Collecting information such as pressure downhole is considered semi-advanced and is helpful for increasing efficiency. Other measurements, such as TOB and WOB, typically are not measured downhole on geothermal rigs unless they use an MWD tool that can measure them. These data are especially helpful for increasing ROP and decreasing time and cost of drilling simply by informing the driller of true bottom-hole conditions. Unfortunately, this information is frequently not used in geothermal operations.

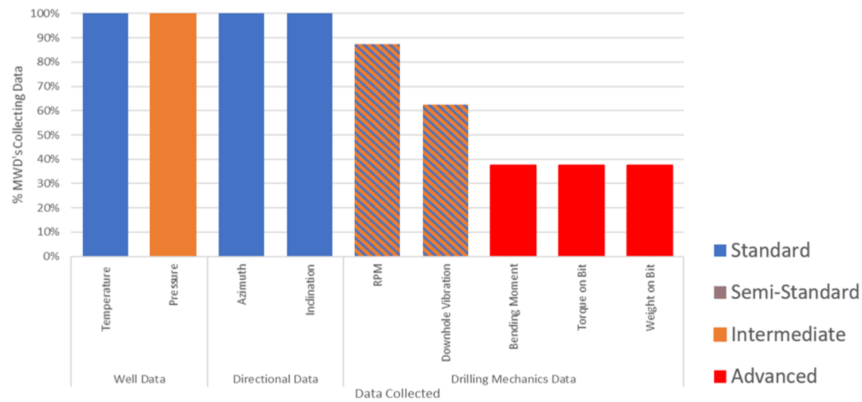

Figure 1. Data collected by M/LWD tools and their frequency of use in petroleum drilling.

As shown in Figure 1, our experts indicated that temperature and directional data are now standard for all petroleum drilling, regardless of the direction of the hole. In geothermal operations, this equipment is used only 50% of the time (Capuano Jr. and Capuano III, 2018). As the well complexity increases, petroleum drillers will use additional measurements such as pressure and drilling mechanics data. These data are not commonly used in geothermal drilling because of temperature limitations of the tools.

3.2 Data Transfer Technologies

The downhole devices are able to transmit near real-time data to the surface or to store the data in a memory device to be reviewed back at the surface. Table 2 lists several mechanisms for transmitting data to the surface.

The most common and reliable MWD tool available today uses **mud-pulse telemetry** to send information to the surface. This tool creates small pressure waves within the mud, which are decoded at the surface and allow usable real-time information to be collected. The pressure signals are in binary code and can be positive- or negative-pressure pulses or frequency-modulated waves. Drillers use this to take continuous measurements. To comply with state and federal regulations, MWD operators will take a stationary measurement when a joint of drill pipe is added or removed, which is typically every 30 to 90 feet (10 to 30 meters). For a stationary measurement, mud-pulse telemetry typically takes about 2 to 7 minutes to receive data and get usable information. This is often longer than it takes to attach the next joint of drill pipe and will lead to a couple of minutes of non-productive time (NPT) every time a stationary measurement is taken (Starkey and Delashmutt, 2018).

Electromagnetic (EM) telemetry allows for information to be sent to the surface more quickly, needing less than a minute to receive the data package. This method is much quicker than mud-pulse telemetry, but it will not work in areas where the surrounding rock is too conductive or resistive (i.e., areas with high water or salt content). Some MWD tools now come with dual telemetry, allowing for EM telemetry when the conditions are right and switching to mud-pulse telemetry when a conductive or resistive formation occurs (Starkey and Delashmutt, 2018).

Acoustic telemetry uses sound waves and a series of amplifiers along the drill string to allow for real-time data collection. This method is seldom used because it cannot provide as much data as other forms of telemetry. However, technology for acoustic telemetry continues to improve and could become more viable in the future (Long, 2018).

In some scenarios, **wired drill pipe** is used instead of telemetry. This method uses specialized drill pipe with wire along the inside diameter to directly transmit data to the surface, allowing for near-instantaneous downhole data collection. Unfortunately, this drill pipe can be very expensive and cannot be used in high-temperature environments, which limits its use in geothermal drilling operations (Long, 2018).

Downhole memory tools are another method that can be used in drilling operations. These tools can take directional and drilling mechanics data downhole and are primarily used as a means of collecting and storing downhole data for post-drilling review. These memory tools do not transmit data to the surface and have comparable temperature limitations to most MWD tools (150°C) (NOV, 2018). Examples of downhole memory tools currently on the market are NOV's BlackBox, Halliburton's Cerebro, and Schlumberger's Dori.

In high-temperature geothermal wells, a downhole MWD tool or wired drill pipe are not commonly used. The high cost of replacement of these tools, should they burn up downhole, make them uneconomical. When downhole measurements are required (e.g., directional measurements are often required by regulation every 100 feet), a **wireline retrievable tool** is used to get downhole information. These tools are often used for obtaining directional data and are either dropped or pumped downhole to take a survey. Because they are in the hole for a limited time with cool circulating fluid and can be designed with protective casing, they can often be operated in wells with bottom-hole temperatures above 300°C. These tools can be very time-consuming to use because of circulating and tripping times, which can add up to significant non-productive time over the course of drilling a single well (Starkey and Delashmutt, 2018).

Table 2. Comparison of conventional downhole telemetry systems (adapted from de Almeida, 2015).

	Mud-Pulse Telemetry	Electromagnetic Telemetry	Acoustic Telemetry	Wired Drill Pipe
Time to Collect Data	2–7 minutes	<1 minute	2–7 minutes	near instantaneous
Data Quantity	high	medium	medium	very high
Signal Strength	medium	low	low	N/A
Signal Interference	medium	high	medium	low
Cost	low	medium	medium	high

3.3 Use of Data and Sensors in Geothermal

The petroleum industry has contended with elevated temperatures and pressures for years, and Schlumberger uses guidelines that organize high pressure/high temperature (HPHT) wells into three categories (see Figure 2), according to commonly encountered technology thresholds (Avant, 2012).

- ***HPHT*** wells begin at 150°C [300°F] bottom-hole temperature (BHT) or 69 MPa [10,000 psi] bottom-hole pressure (BHP). This threshold relates to the behavior of standard elastomeric seals.
- ***Ultra-HPHT*** wells exceed the practical operating limit of existing electronics technology—greater than 205°C [400°F] or 138 MPa [20,000 psi]. At present, operating electronics beyond this temperature requires installing internal heat sinks or placing the devices inside a vacuum flask to shield the electronics from the severe temperatures.
- ***HPHT-hc*** classification defines the most extreme environments—temperatures and pressures greater than 260°C [500°F] or 241 MPa [35,000 psi]. This is the range for geothermal wells and thermal-recovery wells where BHTs exceed 260°C.

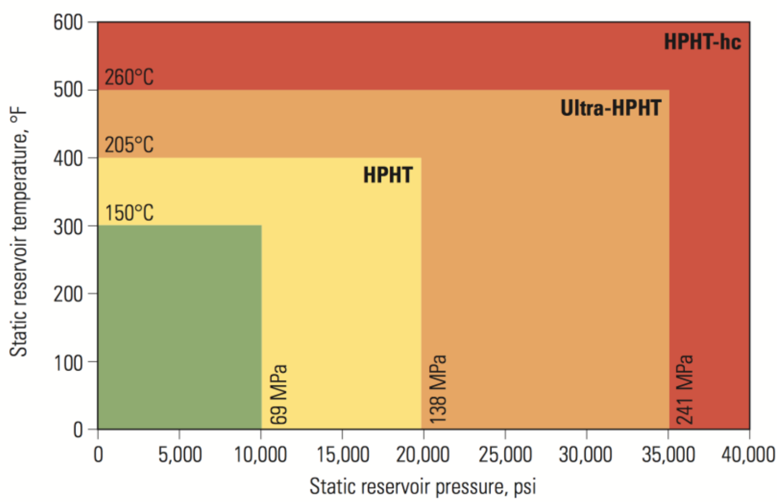

Figure 2. Schlumberger HPHT classification system. The classification boundaries represent stability limits of common well-service-tool components—elastomeric seals and electronic devices. (Avant, 2012)

Because of temperature and cost limitations in geothermal drilling operations, not every data type is collected or can be collected. As shown by Schlumberger's classifications in Figure 2, tools considered HPHT by the petroleum industry (shown in yellow) meet only the lower end of the temperature spectrum for geothermal wells, which are more commonly in the 250°C–350°C range. HPHT conditions also exist in the petroleum industry (Avant, 2012) (Figure 3), so improvements in downhole tool capabilities can benefit both the petroleum and geothermal industries.

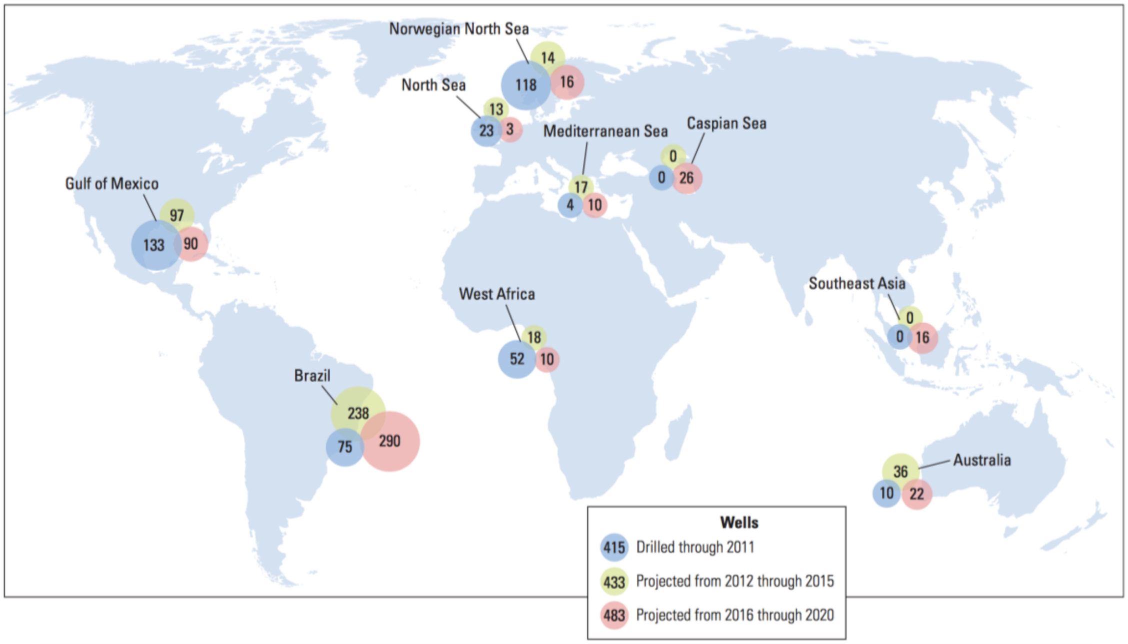

Figure 3. Offshore HPHT activity. HPHT drilling activity is projected to accelerate in the coming years, especially offshore. In the next four years, the number of offshore HPHT wells (green) is expected to be more than double the total drilled in the preceding three decades (blue). By 2020 (pink), the well count is projected to triple. (Adapted from Simmons & Company International Limited, ref. 4. Used with permission.)

The high-temperature environments of geothermal wells prevent the use of most downhole tools, but directional measurements are often required by regulation at specified intervals (e.g., every 100 feet). In this case, geothermal drillers will take a single- or multi-shot survey to get directional information on the well, which can be time consuming and therefore costly. In some scenarios, a single- or multi-shot survey can be taken without tripping out and back into the hole. If the drill pipe is not suitable for this to be done, the project becomes much more time consuming (Starkey and Delashmutt, 2018). To take a measurement in this scenario, the driller needs to trip out of the hole, circulate fluid to cool the wellbore, attach the survey tool on a wireline, pump it to the bottom of the hole to take a survey, retrieve the tool, and trip back into the hole (Capuano Jr. and Capuano III, 2018). On average, a trip can be completed at a rate of around 1000 ft/h (300 m/h) (Eustes, 2018). For example, at the bottom of a 2,500-ft well, a survey would take 5 hours to trip in and out, plus 30 to 45 minutes to run the tool in, take the survey, and remove the tool. Completing this process every 100 feet (though less time consuming at shallower depths) can add up to significant NPT and additional costs over the course of a well. In petroleum operations, an MWD tool would be used to make the measurement and would provide the same data in only minutes.

4.1 Improvement in Tools

Having surface and downhole data are important for enhancing drilling operations, but its use is often not maximized to improve efficiency (Long, 2018). Before electronic equipment, much of the data collected was not accurate. A majority of drilling rig machines, tools, and instruments were developed for use by rig-based personnel, and the main purpose of measurements collected were for safety and failure prevention—not for improving drilling efficiency. Drilling rates relied on experienced drillers and crew who would use their knowledge and hand-kept records to reduce drilling problems (Eustes, 2018).

In the late 1960s, the first MWD tools were invented, allowing for real-time data collection and improved data accuracy. Steady improvements of this technology allowed for increased performance of well development. In the early 1980s, the first LWD tools were introduced, which were especially helpful in petroleum operations because they provided a reliable way to determine rock type and locate hydrocarbon reservoirs. Over time, M/LWD tools have become more accurate and reliable in downhole conditions, which has further improved drilling performance. In the early 1990s, the Electronic Drilling Recorder (EDR) was invented (Pason, 2018). The EDR allowed for more accurate and detailed surface operational measurements of the rig, and therefore, improved rig performance. Figure 4 shows the steady improvement of rig performance that has occurred as crews become adept at using and understanding this electronic equipment.

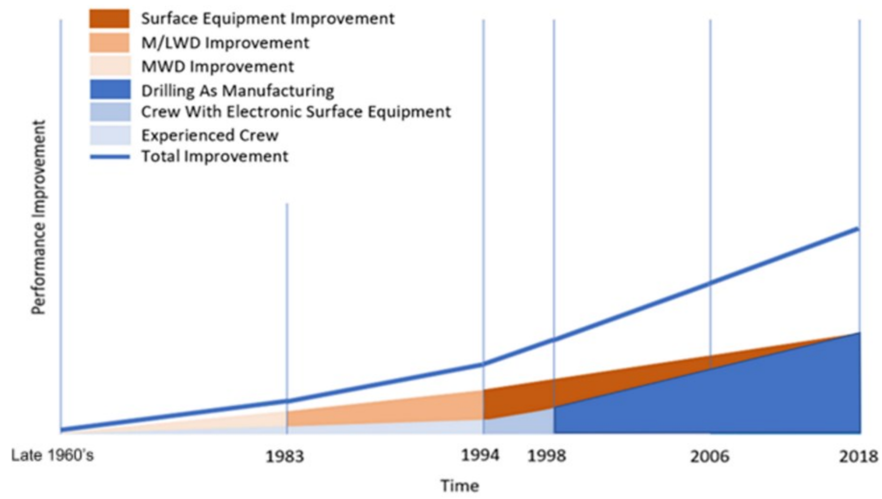

Figure 4. A conceptual graph illustrating phases of improvement in drilling technologies and equipment.

4.2 Time and Cost Improvement Using Downhole Sensors and Data

Using downhole tools such as an MWD significantly improves the accuracy of data collected because drillers are not relying on less-accurate surface measurements. Surface measurements include various boundary effects from torque and drag alongside the drill string, torsional drill-string wrapping, and drilling dysfunctions such as stick/slip, balling, and whirling. These effects are mixed into the surface data, which makes it challenging to separation them out to get true downhole bit conditions.

Downhole data collection has resulted in an overall decrease in the time and cost to drill a well. As shown in Figure 5, taking standard measurements such as inclination, azimuth, and temperature can result in an increased ROP of 32% due to increased knowledge of downhole conditions. These measurements allow for the required directional measurements without the need to trips in and out of the well.

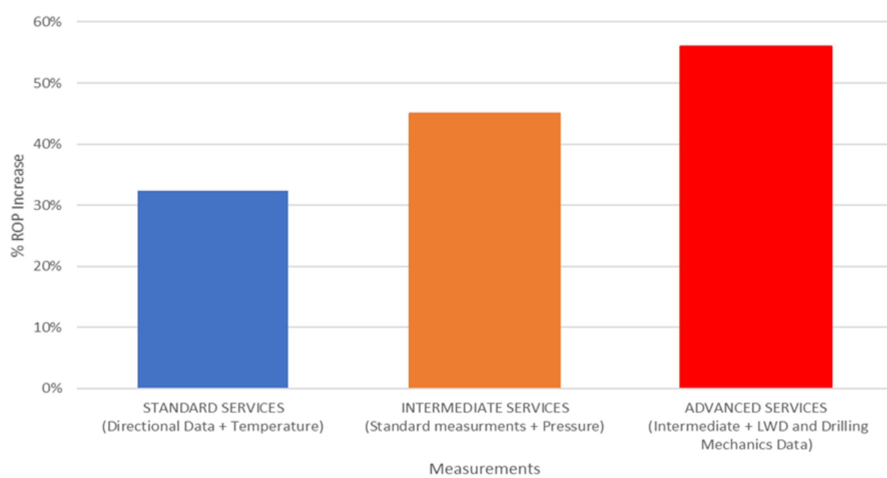

Figure 5. Impact of downhole data collection (and use) on ROP.

When combined with semi-advanced data, such as pressure-while-drilling data, an operation can further improve ROP by an estimated 10%–15% (Bhattacharjee, 2014). Knowing the pressure of the formation can help determine the mud density needed to prevent lost circulation or kicks. Thus, the driller can better maintain the hydraulic/pore pressure differential to lower limits (even underbalanced) for improved ROP.

Using advanced data such as WOB, TOB, bending moment, and LWD measurements allows for additional ROP increases. LWD measurements can provide a much better image of the downhole environment and allows formations to be identified. Accurate WOB and TOB measurements are also important for maintaining a high ROP because it tells the driller the true conditions at the bit. Thus, the driller has greater confidence in applying bit forces and torque closer to the bit's limits, instead of holding a large safety margin due to uncertainty from surface measures. Measurements from the surface are not very accurate for these parameters, so it is more difficult to maintain the desired ROP. The Appendix has specific examples of time- and cost-saving studies.

However, even after 50 years of improving data collection technology, efficiency rates on most petroleum drilling rigs lag behind the current state of the art. Properly analyzing drilling performance to create sustainable, practical, engineering solutions requires quality measurements. The ability of a driller to collect and interpret vast amounts information (e.g., through sight, smell, sound, vibration) has allowed wells to be drilled without complex data collection—although with variable and sometimes unpredictable results. As long as the drillers reach total depth in a reasonable timeframe without too much trouble, specifications for the sensitivity, accuracy, repeatability, and reliability of rig equipment have been relatively non-existent (Drilling to the Limit, 2018). This clearly illustrates the need for continuous improvement in measurements and instruments—even for the petroleum industry.

4.3 Drilling as Manufacturing

Literature suggests that it is standard practice for operating companies and drilling engineers to specify general rig capabilities (total horsepower, hoisting capacity, pump rate, and pump pressure), leaving the details to the drilling contractor. This practice has led to wide variations in process capabilities and a large number of processes that are out of control from a statistical perspective. Recent drops in oil prices have required drilling costs to be lowered for many projects to be economic. Options for cost reduction include 1) material expenses such as cement, mud, and casing, but cutting corners here can lead to potential problems during drilling and in operation and 2) operational expenses, which can be systematically lowered to become more predictable and repeatable.

The concept of lean manufacturing—an improvement upon Ford's assembly-line efficiency—was developed by Toyota after WWII and began to be incorporated into U.S. manufacturing processes in the 1980s (Lean Enterprise Institute). In the 1990s, petroleum industries began a paradigm shift, thinking of drilling as manufacturing (Figure 4). Programs were introduced under various names (e.g., Drilling the Limit, Lean Drilling, the Perfect Well) and were implemented with varying levels of success. But all these programs focus on standardization, optimization, and automation; real-time operations and monitoring centers; and significant reduction in drilling costs.

One example of such a program is Shell's Drilling the Limit (DTL) program. The goal of this program was to get "the best possible performance using current technology" by reducing invisible lost time and error that leads to non-productive time (Successful Energy). Shell immediately noticed performance improvement that led to reduced time and cost of rig operations, although somewhat inconsistently. It was not fully adopted until 2006, when Shell created their revitalized Drilling the Limit (rDTL) program. At that time, increasing drilling performance was a top priority for Shell, and the rDTL program allowed them to implement their DTL program more consistently across rigs to further increase drilling efficiency. The rDTL program focused more on detailed well planning and design, defining key performance indices (KPIs) such as cost per foot, and making performance more accountable to a group by limiting the use of consultants who are not working on the operation for its entirety (Oil and Gas Journal, 2007). Results showed that this improved performance of Shell wells by up to 30%.

Drilling as manufacturing has predominantly been employed in the onshore U.S. petroleum drilling industry, and drilling rates have increased significantly. It is not yet commonplace in the global drilling industry and has not yet made its way into the geothermal drilling industry.

5. DISCUSSION AND CONCLUSION

Petroleum wells have been documented to drill with a ROP of over a mile per day (Livingston, 2016) whereas geothermal wells only have an average ROP of about 125 feet per day (Frone and Boyd, 2018). Although geothermal wells are drilled in more challenging lithologies, the significant petroleum drilling ROP improvements observed due to downhole measurements and drilling efficiency suggest a similar potential for the geothermal industry.

Improvements in downhole technology to allow for HPHT environments could benefit geothermal operations by reducing drilling time and saving operation costs in the process. This improvement could also help drill deeper wells, enabling geothermal energy to expand into new locations and increase energy recovery per well.

High temperatures in geothermal wells limit the use of directional drilling data, which arguably are the most cost- and time-effective pieces of equipment on a rig. Additionally, incorporating HPHT semi-advanced and advanced measurements such as pressure, TOB, WOB, and bending moment could help to increase ROP. Current surface measurements of these data are inaccurate, so having these available downhole would allow for more accurate data and could contribute to a higher ROP. If MWD tools could operate at higher temperatures, the geothermal industry could see a large reduction in drilling time and a subsequent reduction in wellbore cost.

Additionally, reducing the cost of MWD tools could also benefit the geothermal industry. Even if a formation has sufficiently low temperature to use an MWD tool, that does not always mean it will be used. Most MWD tools used in geothermal operations cost between $3,000 and $7,000 per day. In some scenarios, the cost of the MWD tool seemingly outweighs the potential benefit of the increased ROP, so drillers opt to do without (Capuano Jr. and Capuano III, 2018). A lower-cost tool would allow for increased use of MWD tools.

Geothermal operations could also benefit from using drilling-as-manufacturing programs to increase efficiency and reduce lost time. These programs have been proven to increase efficiency in petroleum operations, and they provide immediate potential for improving geothermal drilling in the short term—and even greater improvement in the long term as high-temperature tools contribute improved data to the efficiency analyses.

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8. APPENDIX

Table A1. Cost/Time Benefits of Using Downhole Technology (from Schlumberger).

Location	Goal	Result
Gulf of Thailand	To drill in an environment with static temperatures up to 200°C.	Using Schlumberger's TeleScope ICE ultraHT MWD, drillers were able to successfully complete the well, saving 12 hours of operating time worth an estimated $167,000.
Persian Gulf	To minimize shock and vibration during drilling.	Using a specialized BHA and Schlumberger's PowerPulse MWD, drillers were able to save 6 days of operating time. This resulted in a savings of $744,000.
Russia	To reduce drilling time and cost in a horizontal well.	By replacing their mud motor with an advanced BHA and MWD system, drillers were able to increase ROP by 56%, saving 5 days of operating time.
Sakhalin Island, Russia	To complete two wells in a short timeframe.	Using a rotary steerable system and advanced M/LWD tools, drillers were able to save 7.5 days of operating time. This resulted in a savings of $600,000.
Kuwait	To reduce shock and vibration in an environment with high compressive rock strength.	Using Schlumberger's shock sub tool, the operation was able to increase ROP by 50%.
Russia	To collect real-time data in a high-pressure horizontal formation.	Using M/LWD technology, drillers were able to save 13 days of operating time and increased ROP by 30%.
Eagle Ford Shale Play	To reduce drilling time and cost using directional measurements.	Using MWD technology to record real time directional readings, drillers were able to save 4 days of operating time, a 30% savings.
Kazakhstan	To drill four wells while acquiring M/LWD data.	Using a M/LWD, a rotary steerable system, and high-performance drill bits, this operation was able to save 12 days of operating time with zero NPT.
Negros Island, Philippines	To drill a vertical well and increase ROP.	Using a mud motor and Scientific Drilling's Falcon MWD, drillers were able to increase ROP by 50% and decrease drilling time by 66%.
Williston Basin, United States	To drill horizontal wells while increasing efficiency and eliminating NPT.	Using Scientific Drilling's Falcon MWD, drillers were able to reduce the cost per foot to $130, a 40% cost savings when compared to similar wells.
Russia	To drill a vertical well in a HTHP environment.	Using Schlumberger's PowerPak steerable motor and SlimPulse MWD, drillers were able to finish with an inclination of 0.25° and increased ROP by 25%.