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Geothermal Technologies and Drilling Fluids: New Opportunities and Applications

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Abstract

The pursuit of hydrocarbon-free sources of energy has revitalized interest in both traditional and new geothermal technologies. Drilling fluids utilized in geothermal wells present unique operational applications that extend conventional drilling fluid properties to new and emphasized roles which vary by method of heat extraction.

The cost-sensitive nature of conventional geothermal operations, coupled with frequent incidents of lost circulation, limits the advance of drilling fluid technologies. Regardless of well conditions, drilling fluids remain critical to sustaining the function of downhole tools and cooling the near-wellbore region. This integral relationship between hardware and fluids alters the focus of basic drilling fluid functions found in conventional oil and gas wells.

New geothermal technologies introduce different demands on drilling fluids. Enhanced geothermal wells present an extension of the challenges found in conventional geothermal wells. Other technologies, such as sedimentary geothermal systems, can leverage traditional oil and gas drilling techniques – and even re-purpose depleted oil and gas wells to extract geothermal energy.

As with many advances in geothermal well drilling, conventional oil and gas expertise provides insights that can lead to improved efficiencies and innovations. The authors will discuss the historical relationship of geothermal drilling fluids to well performance, reviewing specific projects and applications and compare them to the latest innovations in geothermal energy extraction techniques.

Introduction

The OPEC oil embargo in 1973 demonstrated the overwhelming dependence of the world on fossil fuel energy. Oil-importing countries subject to the embargo encountered economic disruption from increased prices and shortages of essential energy resources.

As a response, many countries began programs to invest in conservation programs and alternative energy sources that could be generated domestically. Government investment in wind, solar, and geothermal energy production received substantial support through incentives and funding, advancing technologies and expanding adoption (United States Department of State 2022).

As political tensions waned, so did the interest in many alternative energies. The new wave of investment in fossil fuel alternatives is driven by carbon emission reduction. While much of this discussion surrounds wind and solar, limited storage options undermine the reliability of power sourced from intermittent generation (Shellenberger 2021).

The expansion of geothermal energy is just beginning, and many promising, but not proven, geothermal energy systems are under investigation. The oil and gas industry will continue to bring technology and practices to geothermal wells, but the applications require an understanding of well properties, requirements, and economics.

Advantages of Geothermal Energy

Geothermal energy is in a special position to offer a reliable and economical source of constant power at low carbon intensity. Initial capital intensity is balanced by lower, predictable maintenance costs throughout the asset life (Ito and Ruiz 2017).

Levelized cost of energy (LCOE), a common metric for cost comparison, does not account for source intermittency cost. Nevertheless, geothermal remains cost-competitive with many conventional electricity generation methods (Robins et al 2021). The U.S. Energy Information Administration places the LCOE of new installations of geothermal energy at the second lowest of renewable technologies (Oberhaus and Watney 2021).

Unlike large scale wind and solar installations, geothermal energy requires a small surface footprint. Limited surface disruption minimizes land use and reduces the impact to surrounding ecosystems (Oberhaus and Watney 2021).

Geothermal Energy Production

Geothermal energy is a broad term to describe accessing energy from geologic sources of subterranean heat. Geothermal energy is available anywhere; however, the most current economic resources are present where subsurface heat of 392°F (200°C) is closest to the surface, requiring shallower, lower-cost wells (Oberhaus and Watney 2021).

There are several methods to harvest this energy, including many new techniques under investigation. Some of these methods target efficiency improvements at lower temperatures while others target expanding the viability of high temperature reservoirs to new areas.

Conventional (hydrothermal) geothermal electricity production requires high temperature, permeability, and steam and/or brine. Most conventional geothermal wells produce hot brine and reinject cooled brine to maintain reservoir pressure. Dry steam reservoirs, such as The Geysers field in California, are rare but produce significant energy on a per-well basis.

There are many high temperature, lower permeability, dry-rock formations lacking natural water resources for production. Enhanced geothermal systems (EGS) seek to unlock energy from these formations by stimulating the rock and introducing water from surface. These applications would utilize a fractured injection well to improve permeability. A production well drilled into the fractured zone allows the heated injected water to circulate to surface (U.S. Department of Energy 2016).

EGS substantially increases opportunities to harvest geothermal energy, extending existing hydrothermal fields and expanding into new regions. Figure 1 provides a gradient map of EGS potential in the United States.

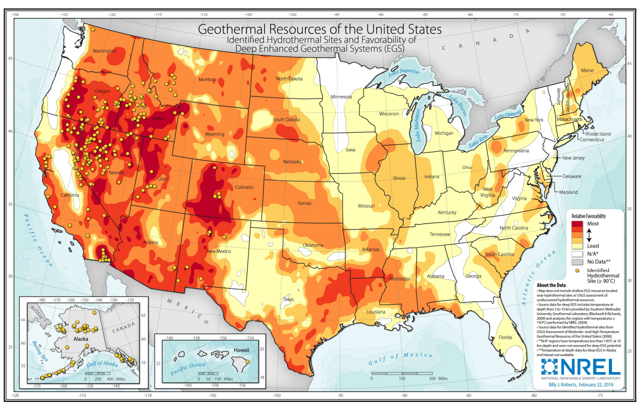

Figure 1: EGS potential in the United States. Dark red is most favorable and yellow is the least favorable. (Roberts 2018) Public domain

Advanced geothermal systems (AGS) use a closed loop where the generation fluid does not directly contact the formation. Instead, it circulates through the heated rock. AGS does not utilize stimulation, which may present earthquake risks, and does not depend upon necessary rock properties or face the risk of uncertainty associated with stimulation.

EGS and AGS have the potential to overlap with existing high temperature hydrocarbon fields, lowering exploration costs. At the end of productive life, it is possible hydrocarbon wells could be converted to EGS or AGS (Robins et al 2021).

Supercritical geothermal systems (SGS) utilize extreme heat to maximize power generation. SGS requires heat exceeding 750°F (400°C), but this in turn generates more energy per well. The Iceland Deep Drill Project (IDDP) seeks to demonstrate the viability of SGS (Think Geo Energy 2022).

Catalysts and Challenges for Technology Advances

Many events are coming together for geothermal energy to see another major expansion into mainstream adoption. There also remain many challenges, particularly if new geothermal technologies are to become economically viable.

Government and Public Support

As the demand for low and zero carbon emission energy continues to grow, so does funding for new ventures. Given the unique benefits of geothermal energy as a continuous power source with few drawbacks, funding to install additional power generation and advance new technologies continues to accelerate.

Governments, universities, and even venture capital firms are providing funding to develop a variety of geothermal technologies. In the United States, the Energy Act of 2020 continues funding for existing activity at the Department of Energy while adding three new Frontier Observatory for Research in Geothermal Energy (FORGE) sites for $170 million in annual funding (Viola, McDonald, and Lane 2021).

Collaboration and Documentation

There are comparatively few geothermal wells, but volumes of data from previous and current projects. Core analysis, daily drilling reports, modeling software, and drilling best practices are available for download, usually at no cost. The free distribution of challenges, lessons, and opportunities aids to lower the risks for new ventures.

Geothermal Rising (formerly the Geothermal Resources Council), the oldest nonprofit geothermal association, provides public education, facilitates industry collaboration, and connects governments, academia, and industry to advance geothermal energy (Geothermal Rising 2022). Similar organizations continue to promote geothermal energy and provide technical studies for use across the industry.

Well Frequency and Geography

Increased geothermal investment elevates the expected well count for the coming years. Historically, 100-200 geothermal wells are drilled each year. To meet government targets by 2030, Rystad Energy (2021b) estimates this number to increase to more than 700 annually. In comparison, 54,000 oil and gas wells are forecast for 2021 and 64,500 wells for 2022 (Rystad Energy 2021a). The comparatively small number of geothermal wells to drill limits the business case for some technologies, similar to the challenges in developing HPHT equipment for oil and gas wells (Beckwith 2013).

Geothermal energy is viable in fewer geographic locations but advances in technology have the potential to expand the landscape. The most active regions trace the "Ring of Fire" along the edges of the Pacific Ocean. Other areas include Italy, Turkey, Kenya, and Iceland. In the United States, the leading producer of geothermal power, more than 90% of geothermal energy is produced from California and Nevada (Robins et al 2021.

Drilling Technology

Between exploration, production, and injection wells, about 25% of geothermal energy costs are attributed to drilling activity (Ito and Ruiz 2017). Advances in drilling technology provide more opportunities to control and lower these costs.

Regardless of the technique, geothermal energy requires numerous wells for a project. 100% reinjection of geothermal fluids maximizes sustainability, naturally requiring more wells to produce energy and return fluid to the reservoir. The upcoming surge in interest for geothermal development complements recent advances in oil and gas drilling, from high temperature equipment to greater drilling efficiency (Feder 2021).

Geothermal Well Characteristics and Challenges

Traditional geothermal facilities utilize producer wells and injector wells. Production wells convey heated water or steam to the generation plant at surface. Injector wells return cooled water to the reservoir to sustain reservoir pressure.

Current geothermal fields target shallower reservoirs that make drilling and development costs more practical. The relatively shallow depths and cost-sensitive nature of these wells does not require a high specification drilling rig; however, many new advances of the latest generation of drilling rigs could bring new levels of automation and data acquisition to geothermal fields, decreasing drilling time and cost.

Density Requirements

Most geothermal fields feature low pore pressures with high temperatures and drilling fluids are unweighted. There are some cases of drilling fluid density requirements up to or exceeding 12.5 lbm/gal (Lackner, Lentsch, and Dorsch 2018, Pallotta et al 2020); however, losses usually limit their use as operations resort to blind drilling.

Active Cooling

Active cooling of the circulating system remains important for safety, equipment life, cementing, and fluid stability. Cooling the fluid at surface prevents steam flashing of the drilling fluid, reducing the risk to personnel.

Circulating cool fluid extends the life of downhole tools. In some applications, this means that specialized high temperature equipment is not required, controlling costs.

Cool drilling fluid limits the potential for drilling fluid to reach downhole temperatures, limiting degradation and product usage. The heat exchange effect lowers the temperature of the wellbore. Saito and Sakuma (2000) performed extensive studies to evaluate cooling techniques, including the effects of spotting cooled fluid on trips.

Hole Sizes

Effective power generation requires large volumes of steam or brine production from each well. Bigger hole sizes are required to meet inflow requirements for economic generation (Finger and Blankenship 2010).

Many wells have 12 ¼” production sections with 9 ⅝” slotted liners (Nugroho et al 2017). An openhole production section, typically utilizing a slotted liner, maximizes reservoir exposure and does not require cementing in place. This reduces the temperature requirement for critical cement jobs to the intermediate casing.

Lost Circulation

Lost circulation can contribute about 10% of the cost of production wells and 20% of the cost of exploration wells (Finger and Blankenship 2010). In sedimentary formations, lost circulation is easier to remediate. In the high temperature volcanic formations that produce the most energy, large fractures and caverns dramatically reduce the rate of success for lost circulation treatments (Goodman 1981).

Most lost circulation material consists of basic materials – cellulose, sawdust, nut shells, and cottonseed hulls. In the production interval, it is surmised that these natural materials will degrade under bottomhole conditions, reducing the risk of formation damage (Rickard et al 2010).

In many cases, attempts to treat lost returns are unsuccessful. Aggressive lost circulation treatments risk plugging downhole and surface equipment, limiting their application. Large voids and fractures limit the performance of squeezes. Cement plugs are regularly attempted with a low success rate due to the nature of the loss zones, high temperatures, and contamination from downhole fluids (Goodman, 1981, Stefánsson et al 2018).

Total losses present a significant demand on water resources. Without water circulating in the well, the risk of a well control event tied to flash steam at surface becomes a major concern. In addition, water must be circulated downhole to cool equipment, cool the near wellbore, and carry cuttings away from the bit (Nugroho et al 2017).

Reverse circulation techniques have been utilized to drill ahead without returns (Rickard 2001 et al, Petty et al 2005). Other hardware solutions may be integral to future geothermal well cost efficiency, particularly given the large water demands of total losses. Studies show regular water demand for a well between 13,000-15,000 barrels of water to drill and cement a typical geothermal well (Alamsyah et al 2017, Clark et al 2011). Pinkstone et al (2018) place this number at 650,000 barrels for geothermal wells in West Java, Indonesia.

Wellbore Instability

Wellbore instability is frequently a function of lost circulation. Severe to total losses make a consistent hydrostatic column difficult to maintain, increasing the risk of sloughing. This sloughing is a common source of pack-off, which can lead to a loss of the wellbore (Nugroho et al 2017).

Hole Cleaning

While few existing geothermal wells feature substantial deviations, hole cleaning challenges center around large cuttings volumes in large wellbores and lost circulation.

Regular sweeps and torque trending are utilized to mobilize and identify cuttings accumulations. Cuttings are carried away from the wellbore into vugs and caverns. Depending on the loss rate and zone, annular velocities may be insufficient to effectively transport cuttings, requiring controlled drilling.

Stuck Pipe

Mechanically stuck pipe is a common issue via packoff from cavings or poor cuttings conveyance from lost circulation. Sidetracks are common as the combination of losses, poor hole cleaning, and wellbore instability combine to create a series of challenges that complicate preventing and freeing stuck pipe. The cost associated with stuck pipe can be as high as the cost of a single geothermal well (Prihutomo and Arianto 2010).

Nugroho et al (2017) discuss challenges from Indonesia that readily translate to other regions. One study for a field in West Java calculated 1.9 stuck pipe incidents per well.

Improved drilling practices and quick responses to changes in conditions can help reduce these events, but the risk and frequency remains elevated. Continuous circulation devices have been tested for geothermal applications, which can reduce the risk of packoff during connections (Pinkstone et al 2018).

Cementing

Quality cementing has numerous challenges. A poor cement job can rapidly lead to well failure if water is left behind the casing where it can expand and deform the casing.

To prevent flash-setting of cement, drilling fluid is circulated prior to cementing to cool the wellbore. In some loss-prone areas, sodium silicate pre-flushes are used to minimize losses.

Techniques have been developed, particularly through top-up jobs in the annulus, to make sure remaining fluid is fully displaced during the cement job. Lightweight cement, foam, and reverse circulation techniques (Finger and Blankenship, 2010; Rickard et al 2010) are part of the solution set to address the challenge of complete cement coverage in high loss zones.

Acid Gas and Corrosion

Hydrogen sulfide is present in many geothermal fields, creating a health and safety concern and increasing corrosion risk. Hydrogen sulfide is present in higher concentrations in high temperature fields while low temperature, brine dominated fields have a much lower occurrence. Carbon dioxide is a particular problem in some fields, requiring titanium casing to mitigate corrosion (Finger and Blankenship 2010).

A corrosion control program is essential because high temperatures accelerate any corrosion process. Despite the extreme environment, corrosion control and monitoring follow many standard procedures, utilizing corrosion rings, elevated pH, and other standard practices (Tuttle, Listi, and Tate 2020).

Geothermal Drilling Fluid History

Geothermal drilling fluids must balance low-cost well delivery with extreme temperatures. Traditionally, geothermal drilling fluid system design focused on controlling gelation through low solids, dilution, and thinners.

Early generation (mid-1970's) drilling fluids consisted of a freshwater base with bentonite. As the system flocculated at temperature, organic thinners, such as lignite, were added to address gelation and potential solidification. These thinners were primarily organic in nature. Thermal decomposition created acidic materials, aggravating corrosion (Remont et al 1977).

Subsequent formulations utilized sepiolite for viscosity. Bentonite remained a small component for supplemental fluid loss, but a reduced concentration limited gelation issues (Carney, Leroy, and Meyer 1976; Zilch, Otto, and Pye 1991).

Today's geothermal drilling fluids are based on the following generation of thinners and filtration control additives. Synthetic polymers, performing as both filtration control aids and thinners, provided greater stability and performance at low concentrations. Their high temperature stability and tolerance to contaminants, particularly to electrolytes and alkalinity, dramatically improved fluid maintenance. For cost efficiency, lignite remained in the system, but at low concentrations (Zilch, Otto, and Pye 1991).

One common deflocculating co-polymer is sulfonated styrene maleic anhydride (SSMA), with a decomposition temperature exceeding 752°F (400°C). Vinyl sulfonated copolymers provide supplemental filtration control and viscosity. Since these advances, very little has changed. Tuttle (2005) discusses the same or similar products as those used 20 years prior. Rickard et al (2010) utilize the same products while introducing new cellulosic lost circulation material. Table 1 compares a formulation presented as the latest generation to a formulation from 1980.

Table 1: Drilling Fluid Formulation Comparison

Product	Formulation from Rickard et al 2010	Formulation from Zilch et al 1980
Bentonite	10-20	15
Sepiolite	-	-
Lignite	-	1
Treated Lignite (modified, causticized, resonated)	0.5-3	2
SSMA or similar	0.2-0.5	.75
Vinyl sulfonated copolymer	0.25-2	.75

Outside geothermal applications, the latest high temperature polymers are from the same family as the original synthetic polymers, but with modifications to improve performance. Developed for high temperature, high pressure wells, they are currently cost-prohibitive for geothermal drilling fluids.

Geothermal Drilling Fluid Opportunities

Geothermal drilling is expanding into new areas. Some of these areas may directly overlap oil and gas drilling, while others are entirely new. Oil and gas drilling provides lots of insight, but objectives and risks are not the same.

Technologies that integrate with geothermal well operations require drilling crews and drilling fluid specialists trained to identify potential hazards as they develop and react appropriately.

Drilling Fluid Technical Requirements

API Recommend Practice 13L (2020) provides a helpful guideline for drilling fluid evaluation and qualification. The standard of dynamic ageing for 16 hours at bottomhole temperature, and this is regularly cited as a minimum standard. The document cites that a cooled wellbore from fluid circulation may merit a lower test temperature is appropriate for the 16-hour duration. Static ageing is recommended for a minimum of 16 hours with longer times set as appropriate.

While the well and applications-specific qualifications for testing are in clear text, many fluid design specifications require stability for the minimum of 16 hours at bottomhole temperatures. Equipment capable of reaching temperatures above 400°F (204°C) is limited even if products are available to reach common geothermal reservoir temperatures.

The requirements for most geothermal drilling fluids include several basic considerations:

- Controlled viscosity at circulating temperature
- Minimal gelation/thickening during static periods
- Cement tolerance
- Elevated pH for corrosion and acid gases

Most qualification procedures include dynamic ageing at an expected temperature well below bottomhole temperature and static ageing at bottomhole temperature, with a focus on gelation. The lowest cost solutions follow the pattern of recognizing dynamic requirements while ensuring the static fluid, even if degraded beyond use, is still mobile for circulation.

Given the frequency and scale of losses, cement contamination is an important test. Many wells require multiple cement plugs. The difficulty in placing them increases the likelihood for contamination of drilling fluid if returns are restored.

Invert Emulsions

As early as 1976, Remont et al (1976) highlight the benefits of invert emulsions. Based on their tests, elevated temperature stability and corrosion mitigation were noted as distinct advantages to water-based drilling fluids. Environmental concerns were raised with conventional base oils of the time, which could potentially be addressed with friendlier base oil options today.

Bland et al (2006) cite an invert emulsion formulation stable to 550°F, which may meet requirements for some geothermal wells. Given the cost sensitive nature of geothermal drilling and substantial risk of losses, it is unlikely that new, extreme-temperature invert emulsion systems are practical options. The standard for high temperature stability increases with the risk that partial degradation of oil-wet surfaces can create concentration cells for aggressive corrosion attack.

Regular encounters with hydrogen sulfide while drilling also makes invert emulsions less appealing because managing this deadly gas is best performed with water-based drilling fluid.

Loss Mitigation

If a new strategy and/or materials are developed to minimize losses, the economics of new fluids systems dramatically improve. Without returns, most drilling fluids are expensive and impractical to maintain. The frequency and extent of losses usually requires multiple cement plugs until the decision is made to drill blind with water and sweeps.

Current LCM treatments include common materials such as cellulose, nut shells, and graphite; however, the limited success rate prevents consideration of more expensive materials.

High fluid loss squeezes are used on occasion, but they seldom perform. The next option, cement plugs, have a similarly high failure rate and require time to cure, increasing delays.

Expandable and settable materials may provide significant savings in highly fractured zones. Their ability to conform and seal large openings has the potential reduce time attempting to remediate losses and maintain circulation. Anything that can eliminate the time to place and wait for a cement plug to cure offers significant rig time savings.

Most expandable and settable products perform based upon chemical reactions, requiring accelerators and retarders for effective performance – and to limit the risk of premature activation at surface or in the drill string.

Polyurethane grout has been tested, but material and deployment techniques are far from mature. It is possible that new loss treatments integrate hardware, such as high temperature expandable packers, for precise placement (Glowka 1997).

Density Management

Most geothermal fields have low pore pressure. Drilling fluids are unweighted to minimize the risk of losses. There are several fields with higher pore pressures, requiring elevated density. Fine grind weight material is preferred to minimize sag risk; however, solids-free or ultra-fine (sub-micron or nano) materials could eliminate the risk completely.

Beyond drilling fluids for continuous circulation, managed pressure drilling (and the variations within that term) can aid to prevent losses and improve wellbore stability.

Real-Time Dynamic Temperature Modeling and Optimization

Fluid conditions, hole conditions, and equipment longevity are all subject to the duration of exposure to high temperature. In the fluid design phase, a practical set of requirements based on expected conditions will help to create appropriate test criteria. Drilling fluid programs and rigsite practices can be adjusted to real-time drilling activity. For example, the static temperature model can identify the depths to break circulation when staging in the drilling assembly back to bottom.

Wellbore cooling helps extend the limits of many tools and chemicals, including cement; however, cooling can lower the fracture gradient, increasing the risk of losses (Gonzalez et al 2004). Understanding these effects and optimizing wellbore temperatures may help to reduce the risk of losses while maintaining sufficient cooling for other tools to function.

Models may also account for thermal properties of fluids, which will vary by base fluid, viscosity and solid content. It is possible that ideal fluid properties can target both drilling performance and temperature profile. Conventional geothermal wells do not feature production tubing, but should new technologies include them, insulating packer fluids and vacuum insulated tubing can assist to retain heat to surface.

High Temperature Polymers and Thinners

The newest high temperature synthetic polymers remain expensive. They are designed to tolerate many contaminants found in traditional geothermal wells. Lower cost versions of these products may provide a new generation of viscosifiers, filtration control additives, and thinners with more precise control.

Air Drilling and Foams

Drilling with air, when feasible, increases rate of penetration and eliminates the risk of losses. Air drilling has been used on many projects, but it has fallen out of use in recent years. Corrosion mitigation requires nitrogen or some other gas to limit oxygen corrosion.

Zhang et al (2012) utilized foam drilling fluid as an essential technology during a 57 well campaign in Kenya. Aqueous foam was utilized in combination with viscous sweeps and water flushing to cool the wellbore prior to cementing.

Foam systems provide a low-density circulating fluid with the carrying capacity to convey cuttings. For loss-prone geothermal wells, foam fluids have always been of interest due to their simplicity, but high temperature stability remains a challenge (Rand and Montoya 1983).

Foams have low heat capacity and low thermal conductivity, eliminating the cooling benefits of a conventional drilling fluid, but they also heat more slowly.

High temperature foams have the potential to reduce losses and, more importantly, reduce water requirements for geothermal wells. A significant tradeoff is their limited ability to cool the bit.

Thixotropic Fluid Systems

Highly thixotropic materials fluids such as mixed metal hydroxides and mixed metal oxides (MMH/MMO) thicken in regions of low shear. Their ability to minimize losses, particularly in combination with other LCM (Offenbacher et al 2018), offer a potential opportunity. Paiuk et al (2004) demonstrated an MMH/MMO system using select bentonite stable beyond 400°F (204°C).

In addition, highly thixotropic fluids improve hole cleaning performance in the large annuli of most geothermal wells. Applied as a system or in sweeps, they offer superior carrying capacity to xanthan gum and limit potential washout at the near-wellbore.

Formation Damage

Formation damage occurs in many forms. In many well applications, including EGS, drilling fluid formation damage concerns are limited because post-drilling perforation and hydraulic fracturing will bypass damage at the near-wellbore.

Blind drilling is common in the reservoir and in many cases expected. It is the hottest portion of the well and where drilling fluid components are the most likely to break down; however, new geothermal systems may be placed in new areas where losses are less prevalent.

Recognizing potential damage mechanisms, particularly in openhole completions where permeability must be preserved, will impact fluid options. A new concept – thermal degradation of materials – may ultimately expand the toolbox when compared to traditional reservoir drill-in fluids.

Conclusions

Renewed interest in geothermal energy creates new opportunities for geothermal well drilling:

- New technologies expand the potential geographical areas and formations where geothermal energy may be feasible
- Geothermal wells have many similar challenges to oil and gas wells, but geothermal drilling is not the same
- Geothermal drilling fluid opportunities include existing solutions adapted from oil and gas experience as well as completely new solutions
- The greatest opportunities to advance geothermal well drilling requires a recognition of geothermal drilling practices and their distinctions from oil and gas well drilling

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