Proceedings World Geothermal Congress 2020+1
Reykjavik, Iceland, April - October 2021

Application of an Engineered Drilling Fluid System for Drilling an Ultra HT Geothermal Well in Central Italy

Davide Pallotta, Alessandro Dei (Enel Green Power), Lucio Bussaglia, Alessandro Cascone (Newpark Fluids Systems)

Newpark Fluids Systems, Via Salaria, 1313/c, 00138 Roma RM, Italy

LBussaglia@newpark.com, ACascone@newpark.com

Keywords: Italy, Geothermal, Drilling Fluid, Engineered, Newpark, High Temperature

ABSTRACT

The Italian National Research Council and a local geothermal operator jointly drilled an ultra-high temperature, exploratory geothermal well in the Tuscany region of Central Italy. A degree of uncertainty existed in the well design with respect to bottom hole temperatures (BHT) to be encountered when drilling the 8 ½" and 6" hole intervals. Information from offset well analyses indicated that bottom hole temperatures could approach 450° C (842°F) at the planned total depth (TD) of 3,500 meters (11,483 feet). The hostile operating environment required a robust, engineered geothermal drilling fluid design to satisfy the drilling operational objectives of this well. The water-based geothermal drilling fluid was designed with a density of 1.5 sg (12.5 lbm/gal) and with thermal stability to allow enough time to conduct tripping operations without impact fluid stability. Important design criteria for the engineered geothermal fluid design were rheological properties for cuttings transport, and thermal integrity to prevent gelation and flocculation at extreme temperature conditions. The drilling fluids service provider conducted extensive testing of the fluid design at their research center in Rome, where the fluids were static aged at temperatures of 200°C (392° F), which was the upper temperature limit of the test equipment. A thorough analysis of candidate products was conducted to determine efficacy in the provision of rheological and fluid loss control at expected BHT. The rheological and filtration control properties of the system were robust and stable at temperatures of 200°C (392° F), and pressures of 8,000 psi (552 Bar). During the intensive testing campaign different chemistries were for fluid loss and viscosity, to include synthetic polymers and resins. Furthermore, various weighting agents were evaluated to arrive at a final fluid density of 1.5 sg (12.5 lbm/gal), and with a low potential to exhibit density variations (sag) in a high temperature environment. Information from laboratory testing was used to provide operational support and best practices to maintain fluid properties within specifications while the circulated in the hostile temperature environment. Additional operational support was provided from the laboratory in Rome to minimize the potential for lost circulation and stuck pipe events. Emphasis was placed on a robust lost circulation strategy, which include use of an innovative technology to reduce downhole losses utilizing a single-sack additive based on diatomite chemistry, which effectively sealed fractures.

1. INTRODUCTION

Italy is one of the most renowned country worldwide in the geothermal sector. Geothermal energy has been used for centuries to satisfy general heating requirements. The modern geothermal plant is powered by production wells drilled to a source rock to produce steam at the surface. Depending on the location and depth, source formation temperatures vary. Thanks to a favorable geology, its wealth of geothermal resources makes Italy ranked among the top 10 countries for electricity generation (Bertani, 2016) and among the first 20 for thermal applications (Lund and Boyd, 2016). Electricity from geothermal resources nowadays is produced in the Tuscany region, central Italy. The hottest geothermal resources of Italy are in what is called the "traditional" geothermal area of Italy, in the tectonically active regions of Southern Tuscany (Figure 1). These areas host all the national geothermal plants for electricity production and most of the geothermal district heating networks. Geothermal resources are abundant in Italy, ranging from resources for shallow applications (mostly heat pump technology), through to medium (>90°C) to high (>150°C) temperature systems at depths accessible only by wells (usually within 3-4 km). High temperature systems tend to be in tectonically active regions either in volcanic and intrusive or fault-controlled systems (Santilano et al., 2015). Many direct applications of geothermal heat are also located in Tuscany, however thermal uses are widespread in the national territory, with district heating systems mostly localised in the north and other direct uses and ground source heat pumps distributing on a much larger territory (Bargiacchi et al, 2020).

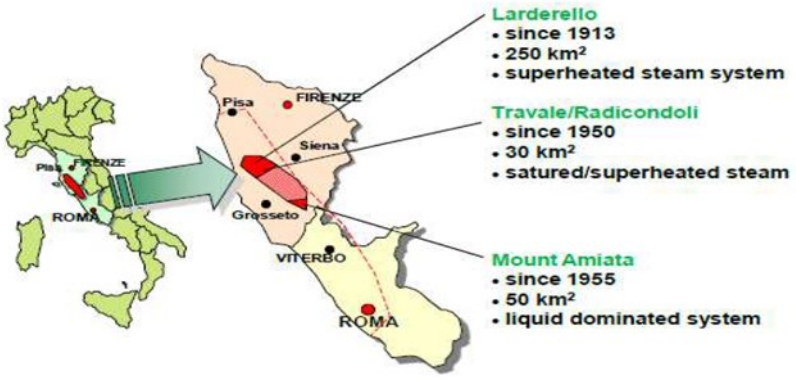

Fig 1: Traditional geothermal areas in Italy (Bargiacchi et al, 2020)

2. GEOTHERMAL DRILLING FLUIDS

High temperature gradient exist in fields where geothermal wells are located, and the extreme temperature environment can adversely affect the properties of drilling fluids, resulting in loss of fluid stability with respect to rheological and filtration control properties. High temperature in geothermal and deep wells can be problematic and are often the primary driver for instability of drilling fluids. As a result of changes in their chemical and physical properties, problems such as gelation can occur (Zilch et al., 1991). A series of different drilling fluids have been used in the quest for a fluid that would perform in the geothermal environment. To evaluate these fluids in the laboratory, standard API test procedures are used to simulate the operational environment with respect to temperatures and pressures. Important design considerations for geothermal fluids center on rheological stability, fluid loss control, and resistance to contamination. This paper describes both laboratory and field results of a robust engineered drilling fluid designed specifically for use in the extreme temperature, hostile conditions of geothermal wells.

2.1 Drilling Fluid Design, Selection and Formulation

After evaluating the expected drilling challenges of this new geothermal field in Central Italy, the project engineers established the following benchmarks for the design of an appropriate technical and cost-effective fluid solution:

- Provide consistence rheology and acceptable fluid loss properties after hot rolling at 204° C (400° F)
- Density of 1.50 sg (12.5 lbm/gal) to offset expected pressures
- Weighting material to minimize sagging when fluid is exposed to extreme hot bottom temperature during tripping

The fluids laboratory mixed and pilot-tested several water-based fluid formulations with the goal to meet all operational needs and provide a cost-effective solution. The customized fluid consisted of a specific blend of chemicals and synthetic polymers designed to be stable at high temperature environment.

Additional investigation and research were conducted to select a proper weighting agent to achieve the desired fluid density with improved sag control. Due to the complexity of wells being drilled in the new emerging areas and unexplored fields, alternative weighting materials were evaluated in place of barite for several technical reasons. Alternative weight materials such as micronized barite, manganese tetra oxide and formate brines have been used in challenging wells such as HPHT, ERD & MPD. Use of these specialty weight agents was often cost-prohibitive and ill-suited for specific technical challenges in these wells. For the scope of this project, micronized ilmenite was evaluated as an alternative weight agent that balanced cost and performance objective and was suitable for use in this geothermal project for these reasons:

- Viewed as a cost-effective solution when compared to alternative weighting materials
- Sag performance in high temperature conditions was significantly improved. As depicted on Table 1, micronized ilmenite particles have a D_{50} of 5 microns, so will settle at a slower rate due to particle size effects. These particles settle at a rate that is 8 -11 times slower than barite and hematite.

Table 1: Settling rate of different weighting agents

Weighting agent	sg	Average Cut Point D_{50} (Micron)	Settling rate (cm/day)
Hematite	5.2	15	39.59
Barite	4.2	15	30.16
Micronized Ilmenite	4.6	5	3.77
Manganese Tetraoxide	4.8	1	0.16

The extensive lab testing campaign confirmed the use of the following key products:

- Sepiolite was selected as clay viscosifier for ultra-high temperature applications. Unlike bentonite, it is not affected by high temperature gelation and which exhibits long-term stability in rheological properties.
- Xanthan gum biopolymer was chosen as the primary viscosifier and suspending agent
- A selected synthetic polymer was introduced to provide fluid loss control in high-temperature conditions
- A product based on humalite chemistry was used for high temperature fluid loss control
- A resinated sodium lignosulfonate powder was used for filtration control and rheological stability at elevated temperatures.
- A synthetic thinner was used to prevent mud gelation of mud when exposed to high temperatures
- Bridging control was achieve using a calcium carbonate based on ground marble chemistry
- Micronized ilmenite was used to achieve required density and to provide control over the potential for sag

The designed fluid formulation and properties are shown in Tables 2 & 3, respectively. After static aging, the HTHP rheology was also performed to evaluate rheological fluid behaviour at bottom hole conditions (Table 4). Figure 2 shows mud after static aging inside the cell. Although the expected temperature was forecasted to be above 250° C (482°F), the formulation was tested at 204° C (400° F) due to equipment limitations.

Table 2: HT WBM Formulation

Products	Function	Concentration (ppb)	Concentration (Kg/m^3)
Water	Base Fluid	0.756 bbl	756 lt
Caustic Soda	Alkalinity	0.5	1.4
Sepiolite	HT Viscosifier	10.5	29.9
Xanthan gum biopolymer	Viscosifier	1.0	2.9
Synthetic HT polymer	HT Thinner	9.0	25.7
Humalite	HT thinner & fluid loss reducer	9.0	25.7
Resinated sodium lignosulfonate	HT Mud stabilizer	10.5	29.9
Synthetic HT polymer	HT Fluid Loss reducer	5.5	15.7
Sized ground marble	Bridging agent	28	79.8
Micronized ilmenite	Weighting agent	188	535.8

Table 3: HT WBM fluid properties before hot-roll (BHR) and after 24 hours after static-aging (ASA) at 204 °C (400° F)

Parameters	Unit	BHR	ASA @ 204 °C for 24 hrs
Density	sg	1.50	1.50
pH	-	9.3	8.9
Rheology Temperature	°F	120	120
600	Dial reading	77	22
300	Dial reading	56	17
200	Dial reading	48	15
100	Dial reading	37	12
6	Dial reading	18	9
3	Dial reading	15	9
PV	cP	21	5
YP	$lbs/100\ ft^2$	35	12
Gels 10”/10’	$lbs/100\ ft^2$	17/44	13/35
API fluid loss	ml/30 min	3.5	5.0
Gelation	Visual check	-	None, Fig 1
Flocculation	Visual check	-	None, Fig 1
Sag Factor*	-	-	0.515

*Sag Factor = Density Bottom/ (Density Top + Density Bottom)



Fig 2: Visual check of mud after static aging inside the cell

Table 4: HTHP Rheology @ 200° C and 8000 PSI

Parameters	Unit	At 200 C and 8000 PSI
600	rpm	10
300	rpm	9
200	rpm	5
100	rpm	3
6	rpm	2
3	rpm	2
PV	cP	1
YP	lbs/100 ft2	7
Gels 10”/10’	lbs/100 ft2	3/6

2.2 Geothermal drilling application

Results from laboratory tests were reviewed with and accepted by the operator and then used to develop an operational program for the geothermal well. The operational and drilling fluid programs for the two planned intervals focused of creation of benchmarks on use of the engineered high temperature geothermal fluid in the field, as follows:

- Substitution of all valve pads of the surface tanks
- Design of a kill fluid able to contain unexpected and unpredictable gas events, with stability to downhole conditions and resistance to degradation due by temperature or exposure to acid gas
- Development and use of an accurate decision tree for use of lost circulation materials (LCM) to cure downhole losses
- Definition of the strategy in the event of a stuck pipe incident
- Reconditioning plan for drilling fluid left in hole for extended periods, such as when tripping pipe

The rig dedicated to this project underwent maintenance for two months in order to change all valves and other parts of the surface circulating system in order to lengthen the path of the drilling fluid and to reduce fluid temperatures at surface. A drilling fluid cooler system was also installed to further increase the cooler capabilities of the surface equipment. The drilling teams focused on procedures to manage expected and commonly occurring operational issues such as lost circulation, stuck pipe and well control. A tactic employed in the event of well control event was use of a high density (1.5 SG), calcium bromide completion fluid that was stored in a dedicate pit decision and was ready to be pumped, if required. This fluid was also planned for use in the event of total loss of drilling fluid properties when tripping, in which case it would be displaced downhole to provide the required hydrostatic pressure support. This latter option was never employed when drilling the two intervals because the engineered geothermal fluid showed excellent stability of rheological and filtration control properties during all tripping operations.

The most critical situation for the drilling fluid was assumed to occur during the tripping operations, when the fluid is exposed to extreme temperatures for periods upwards to 24 hours. Once back to bottom with the bit and initiating circulation, the properties of the drilling fluid from the wellbore were expected to be out of specification and requiring reconditioning. For this reason, a dedicated tank was planned to be used to recover the drilling fluid coming out of hole and for purposes of reconditioning.

Drilling of 8 ½" section F/T 2.522-2.602 mMD: The 9 5/8" casing shoe, set at 2,468m, was milled out utilizing an 8 ½" bit and geothermal production water. Temperatures recorded after 8 hours of static condition in the rat hole were 340 °C (644° F) and the leak-off test (LOT) indicated a maximum achievable mud weight of 1,36 SG (11.3 lbm/gal), which was lower than 1,50 SG expected density. A decision was made to displace wellbore with an engineered, high temperature geothermal drilling fluid with a density of 1.15 SG (9.6 lbm/gal). The formulation of drilling fluid was tuned with a lesser concentration of humalite (10 kg/m³ instead of 25.7 previewed, with the result of a good thinning effect) and the final MW was achieved thanks to addition of Sized Ilmenite. Xanthan gum was used to adjust rheological properties to avoid settling of weighting material until the sepiolite additive was fully hydrated and activated by temperature. The resinated sodium lignosulfonate powder was added to control fluid loss, as well. The first 80 meters of this 8 ½" section was drilled without issues in 16 hours and then a trip was performed to for a bit change and to check borehole stability. The rig was unable to establish circulation when tripping back in the hole due to mud residue which had dried up in the drill string pipes due to high downhole temperatures and plugged the float valve. The blockage was removed after circulating 1.5 m³ of water down the string. The interval was successfully drilled and a 7" liner was run and tied back to surface and cemented.

Drilling of 6" section F/T 2601-2909 mMD: Following completion of cementing operations for the 7" Liner and tie-backs, a thermometer log was run to a depth corresponding to the 7" liner point, and a bottom-hole static temperature (BHST) of 380 °C (716 °F) was measured. Geothermal production water was then displaced into cased hole while operations were made to prepare the engineered geothermal fluid for drilling the 6" interval. The density of the active system was increased to 1.5 SG while also building additional fluid volumes and conduction operations to prepare the rig for the next challenging interval. Treatments of caustic soda (1 kg/m³), sepiolite (30 kg/m³), sodium lignosulfonate (20 kg/m³), xanthan gum (2 kg/m³) and micronized ilmenite (650 kg/m³) were made to the active system prior to the displacement. Surface foam appeared during the mixing of the fluid and was treated with a defoamer based on aluminum stearate. Roughly 50 ppm of H_2S were measured at shakers when drilling operations began and was treated through the addition of a scavenger based on triazine chemistry. The influx of acid gases continued immediately after the displacement, where 90 ppm of H_2S & 45,580 ppm max of CO_2, as well as 3.8% of other gases were detected at shakers, along with a significant reduction in the alkalinity of the system to a pH 7. This contaminated fluid was stored in a reserve tank and quickly reconditioned with use of caustic soda & humalite. This circulating volume was then conditioned through use of a low viscosity fluid with a pH of 12, coupled with the use of humalite to reduce fluid viscosity. This treatment strategy was successfully employed to bring the properties of the engineered fluid back to within operational specifications. The fluid in the wellbore was then kept static for a period of 12 hours and, once circulated, only a small gas (0,7%) was recorded and mud properties were all within specification. While drilling the 6" interval all attempts made to control filtration properties were unsuccessful due to the combined effects of extreme temperatures and residual acid gas. Favorable results were achieved using a proprietary anionic polymer blended with a synthetic carrier which primarily provides viscosity and secondarily provides encapsulation of drill cuttings.

A trip for a new drill bit was then made and, afterwards establishing circulation it was noted that the rheological & filtration control properties, as well as pH, of the fluid left static in the wellbore were significantly degraded. This fluid volume was diluted by 30% and isolated into a separate tank and treated with the appropriate additives to bring properties back into specification. Drilling operations then began, and a stuck pipe event occurred while making a connection. While being able to circulate, the operator was unable to rotate or reciprocate the drill string. Attempts were made to free the pipe through placements of produced water at volumes ranging from 3 to 20 m³, following by displacing the entire wellbore to produced water without success. The fluids provider proposed use of a pipe-freeing pill based on synthetic polyelectrolyte chemistry and afterward placement the pipe was freed, and operations resumed. Drilling continued to a depth of roughly 2,7000 meters when downhole losses began to occur. The bit was pulled out to shoe and produced water was pumped and used to keep the well full. The mud weight was then decreased to 1,35 SG (11.3 lbm/gal) and the losses were cured. Afterwards, the drilling fluid was treated, properties were brought back into specification and drilling operations resumed with an average loss rate of 2 m³/hr. A 2nd stuck pipe event occurred when the top drive was momentarily shut down and attempts were made to free the pipe using produced water pills, without success. The pipe was freed after placement of a stuck-pipe pill based on synthetic polyelectrolyte chemistry and operations continued using produced water as the drilling fluid. Total losses occurred after drilling roughly 15 meters with produced water and a high fluid loss pill was then prepared as per the operational plan. The remedial pill was prepared and placed across the loss zone utilizing a hesitation squeeze process with an initial pressure of 200 bar. After 8 hours a second pressure test was conducted and a pressure of 250 bar was recorded. A second pill was then prepared, but with the addition of fine and medium-sized calcium carbonate to provide additional bridging to the loss zone. An initial pressure of 200 bar was recorded, followed by a short trip and leak-off test (LOT) with only 18 bar of pressure. The decision was made to drill ahead using produced water, coupled with high-viscosity pills to facilitate cuttings transport. A second thermometer log was then performed, recording a BHST of 504 °C (939° F). Afterwards, drilling operations continued, without the incidence of losses or wellbore instability, utilizing produced water treated with a corrosion inhibitor and with the use high viscosity pills. Attempts to recover a core were then made by running the coring equipment to bottom, when a gas event occurred during coring operations. At the end of the coring process, and while circulating bottoms up a 2nd gas event occurred and the core was recovered to surface. A trip was then made back to bottom with 3 ½" drill pipe where BHST in the range of 480-600°C (896-1,112° F) were recorded using a thermometer tool utilizing a colorimetric scale. Due to continued gas events, it was decided to plug the last 50 meters of the well with cement, and the well was then left under the control of the National Council of Research for further studies.

2.3 Lost Circulation & Stuck pipe events

The most expensive problem routinely encountered in geothermal drilling is lost circulation, which is the loss of drilling fluid to pores or fractures in the rock formations being drilled. Lost circulation represents an average of 10 percent of total well costs in mature geothermal areas, and often accounts for more than 20 percent of the costs in exploratory wells and developing fields (Saleh et al 2020). Well costs, in turn, represent 35 percent to 50 percent of the total capital costs of a typical geothermal project. Therefore, roughly 10 percent of the total costs of a geothermal project can be attributable to lost circulation. Geothermal reservoirs are typically under pressured, and this increases their susceptibility to lost circulation. In many cases, geothermal wells have been abandoned because of lost circulation issues, which can quickly put a geothermal project into economic difficulty. Thus, developing improved methods and smart materials that can effectively seal the cavernous-type rocks in geothermal wells can positively impact the total cost of the project. One of the major challenges with developing geothermal resources is high drilling cost (William et al. 2008). Several studies have established that drilling can make up to 30% to 70% of overall project cost (Lowry et al. 2017). A recent study

identified that geothermal wells on average takes 56.4 days longer to be drilled than comparable and oil and gas wells. Finger and Drilling cost is either because of low ROP (rate of penetration) or attributed to other drilling problems such as lost circulation and severe wellbore stability issues. Lost circulation is very common in geothermal wells because of the typically fractured nature of the formations in a geothermal field or lost circulation while cement operation (Cole et al. 2017). Lost circulation is a persistent problem in geothermal drilling and is frequently the root cause of other wellbore integrity problems including sloughing, caving, washouts, or bridging. The time and material costs for lost circulation can represent 10% of the total well costs in a mature geothermal field, and often exceeds 20% of the costs for exploratory wells and reservoir development (Almagro et al. 2014). The type of rocks in geothermal applications are usually cavernous hard rocks, and drilling environments tend to be under-pressurized with multiple zones of highly fractured and altered material (Finger and Blankenship 2012). This makes lost circulation more common in geothermal drilling than in other applications. Demand for renewable resources leads to increase of geothermal drilling activities. Well cost contributes up to 40 % of total geothermal project cost. Drilling in geothermal faced many challenges due to its natural characteristics. The most common problems are lost circulation and pipe stuck (Nugroho et al. 2017). Highly fractured zone is the ideal spot for geothermal production. Lost circulation is common in highly fractured formation. Stuck pipe is another problem. Stuck pipe can lead to extra cost of lost-in-hole and fishing operation. Water played an important role in geothermal drilling, not only to keep the wellbore pressure but also to cool down the temperature.

To define the lost circulation decision tree the study started from the kind of losses mechanism and its rate. The below schematic summary will show the different option expected:

Table 5: Losses scenario

Type of Losses	Loss Rate (m^3/hr)	Typical Formations
Seepage	< 3.0	- Porous & Permeable
Partial	3.0 – 10.0	- Small nature or induced fractures
Severe	10.0 – 80.0	- Larger natural or induced fractures
Total	>80	- Cavernous formations - Large and numerous natural or induced fractures

An accurate analysis on the type of lost circulation material to deploy in geothermal application was performed in the pre-well planning process. The extreme temperatures expected downhole led to the decision to utilize only inert materials to avoid unexpected effects arising from use of organic compound due to critical temperature, including induced gas events. LCM recipes for the different loss rate were based on different size based of calcium carbonate and mica materials. In case of large fractures that can lead to loss rates higher than the rig's capability to keep the well full, different options were investigated through the usage of unconventional loss circulation solutions. Most of them were rejected due to their environmental impact, or because they were based on cross link polymers, which were deemed to be too sensitive with respect to setting time at high temperatures. Other options evaluated were expandable pills of bentonite, which do not allow the LCM pill to achieve the density required. The decision was taken to utilize a high solids high filtration squeeze made mainly by diatomaceous material with fibers and granular particles. The LCM plan dedicated a chapter on all corrective and preventive measures required to avoid, or at least limitate loss circulation events.

The operational planned also considered the possibility of a stuck pipe event due to the filter cake quality arising from use of Sepiolite as suspending agent at extreme temperatures. The plan suggested use of a synthetic polyelectrolyte, routinely used as to remediate stuck pipe events in geothermal drilling, as the main primary component of the stuck pipe mitigation pill.

SUMMARY AND CONCLUSIONS

The HT Engineered WBM weighted up with Ilmenite was successfully utilized to drill the 8 ½" section from 2.522 m to 2.602 m with a mud weight of 1,15 kg/lt without showing any sag behavior and remaining in spec for the whole section. Final BHST achieved at the end of the 8 ½" section of 380 °C.

This fluid was then weighted up to 1,50 kg/lt (12,5 ppg) to drill the 6" section till 2.721 m where a network of fractures were met and after few attempts to cure them with an high solids high filtration squeeze, composed mainly by an inert material as diatomite due to BHST achieved, was decided to drill ahead blind with geothermal production water pumping HiVis pill based on a liquid PHPA. At well TD, 2.909 m, final BHST recorded was in a range from 480 to 600 °C (716-1.112° F). This extremely high temperature while drilling the 8 ½" interval affected drilling fluid rheological properties and almost no fluid loss control in this 6" section. However, the main concern related to drilling fluid, the sag behavior in case of high temperature, was avoided. Sagging was never recorded while drilling these 2 sections.

Recorded, many times, in particular while drilling this 6" hole section, significant influx of different gasses like H_2, He, CO_2 and H_2S. Few of them are coming from the formation, but for H_2 and He there is still some uncertain around origin that could be due by the metallic origin of Ilmenite.

ACKNOWLEDGEMENTS

The authors wish to thank Enel Green Power and Newpark Fluids Systems for permission to publish this paper and wish to recognize the contributions of Francesca Finamore, Riccardo Chiodo and Nicola Palmieri (NFS) for their support in laboratory tests and a Nicola Caponi (EGP), Marco Pelagatti, Antonio Ascenzo, Tommaso Angerami, Walter Marchese, Saverio Stassi and Emanuele Pietrucci (NFS) for their support in wellsite supervision and operational execution.

REFERENCES

Almagro, S. P. B., C. Frates, J. Garand and A. Meyer, 2014. "Sealing Fractures: Advances in Lost Circulation Control Treatments." Oilfield Review 3: 4-13

Bertani, R.: Geothermal power generation in the world 2010-2014 update report. Geothermics, 60, (2016), 31-43.

Bargiacchi, E., Conti, P., Manzella, A., Vaccaro, M., Cerutti, P., and Cesari, G.: Thermal Uses of Geothermal Energy, Country Update for Italy, Proceedings, World Geothermal Congress 2020, Reykjavik, Iceland, April 26 – May 2, (2020).

Cole, P., Young, K., Doke, C. Geothermal Drilling: A Baseline Study of Nonproductive Time Related to Lost Circulation. Proceedings at the 42nd Workshop on Geothermal Reservoir Engineering, Stanford, California, February 13-15 (2020)

Finger, J. and Blankenship, D. 2012. Handbook of Best Practices for Geothermal Drilling

Lowry, B. and Nielson. Application of Controlled-Porosity Ceramic Material in Geothermal Drilling. Proceedings at the 43rd Workshop on Geothermal Reservoir Engineering, Stanford, California, February 12-14,(2018

Lund, J.W. and Boyd, T.L.: Direct Utilization of Geothermal Energy 2015 Worldwide Review, Geothermics 60, (2016), 66–93.

Nugroho, W. A., Hermawan, S., Lazuardi, B. H., Mirza, R., Drilling Problems Mitigation in Geothermal Environment, Case Studies of Stuck Pipe and Lost Circulation, Society of Petroleum Engineers, SPE-186922, SPE Asia Pacific, Jakarta, Indonesia, 17-19 October (2017)

Saleh, F., Teodoriu, C., Ezeakacha, C., Salehi, S., Geothermal Drilling, A Review of Drilling Challenges with Mud Design and Lost Circulation Problem, 45th Workshop on Geothermal Reservoir Engineering, Stanford, California, 10-12 February (2020)

Santilano, A., Manzella, A., Gianelli, G., Donato, A., Gola, G., Nardini, I., Trumpy, E., Botteghi, S.: Convective, intrusive geothermal plays: what about tectonics? Geoth. Energ. Sci., 3, (2015), 51-59.

Williams, C. F. Reed, M. J., Mariner, et al. 2008. Assessment of Moderate- and High-Temperature Geothermal Resources of the United States. USGS Fact Sheet 2008–3082, (2008)

Zilch, H.E., Otto, M.J., Pye, D.S., The Evolution of Geothermal Drilling Fluid in the Imperial Valley, Society of Petroleum Engineers, SPE-21786, SPE Western Regional Meetings, Long Beach, California, 20-22 March (1991)