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DEEP GEOTHERMAL WELL COMPLETIONS: A REVIEW OF DOWNHOLE PROBLEMS AND SPECIALIZED TECHNOLOGY NEEDS

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ABSTRACT

Most geothermal wells produce low pressure steam or hot brine from relatively shallow depths. Traditionally, geothermal electric plants have been built on the edges of tectonic plates where high temperature geothermal resources are available near the surface. Recent improvements in drilling and extraction technology have enabled the creation of geothermal power plants in areas where the thermal resources lie deep under the surface.

Temperatures up to 600°F and 100% aqueous environments create well completion and operating problems that are unique to even experienced petroleum engineers. Unusual problems with casing that is otherwise properly designed for basic tension, burst and collapse are presented. Primary cementing limitations caused by severe hole conditions are also emphasized. First of their kind completion tools and methods, and unique problems in a major Australian geothermal development are reviewed.

INTRODUCTION

In several areas of the world, geothermal resources have been favorably assessed and wells are now being drilled and completed with the potential to supply power for electricity generation. Such wells typically will flow large volumes of superheated water from which commercial quality steam will be separated. Viable operations are already supplying electricity in several areas around the globe, including developments in Australia. These developments represent a challenging set of downhole conditions and reservoir characteristics with unique problems caused by high-volume, hot water flows.

This paper is an overview of state-of-the-art technology, problems encountered and limitations relevant to the completion and production of geothermal wells. Technical discussion will include:

1. Casing failure modes, design considerations and the effects of unique hole conditions.

2. Completion methods as applied to a specific project in Australia.

Extensive testing and tool design work were conducted as part of a program to commercialize a geothermal development in the Cooper Basin area of Australia. Two important objectives were early definition of practical problems and rapid technology development.

Formation Description

The Cooper Basin region straddles the Queensland/South Australia border (Figure 1) and forms part of a large area of uniquely high-heat flow attributed to Proterozoic basement rocks enriched in radioactive elements (Meixner and Holgate, 2009).

Figure 1. Location of the Cooper Basin in Australia.

Heat producing granites, including granodiorite of the Early to Mid-Carboniferous Big Lake Suite, lie beneath the Cooper and Eromanga basin sequences, which provide a thermal blanketing effect resulting in temperatures as high as 270°C. The high-heat producing granite formations in the Cooper Basin lie over 13,000 ft below the surface and require hydraulic fracturing to increase surface area for efficient heating of injected water.

STATE-OF-THE-ART TECHNOLOGY DEVELOPMENT

Casing Design Considerations

Most geothermal wells are relatively shallow, typically 5,000 to 9,000 ft. Reservoirs are normally underpressured relative to a full column of fresh water and wells are produced at maximum attainable rates through open casing strings to minimize friction loss. Factors that limit casing diameter are cost, drilling and cementing problems in large diameter holes, and collapse rating limitations. These issues and many more are magnified when depths exceed 14,000 ft and temperatures exceed 600°F. Proper injection well design is equally important. Reinjection of cool brines to the producing zone is required in certain large-scale geothermal projects. Injection wells have large diameter tubing, and completion programs need to consider reservoir injectivity, per well pressure/rate requirements and spacing.

Completion Method Design and Operation

Outside of the temperature and pressure requirements, both the liner and completion installations were relatively conventional. The completion was designed in two phases. The first phase was the installation of a two-stage, cemented 7” liner and tie-back followed by the installation of a 7” x 4-1/2” production packer. Based on previous wells drilled by the operator, it was determined that the existing 9-5/8” casing would not be strong enough to handle the pressures seen during stimulation and injection, necessitating the requirement for both a secondary string of casing to be run and cemented, and a further production string run. The basic program was to first run and cement a 7” liner on a liner hanger — this would cover up the CO_2 producing zone (Figure 2A). The second run was a scab liner run on a liner hanger packer, also cemented in place (Figure 2B). After drilling out all of the float equipment, a 7” x 4-1/2” production packer was installed (Figure 2C), followed by both a 7-5/8” x 7” tie back and a 5” x 4-1/2” production string (Figures 2D and 2E).

Tool Design and Testing

Due to the extreme nature of this application, tools fitting the requirements did not exist. Therefore,

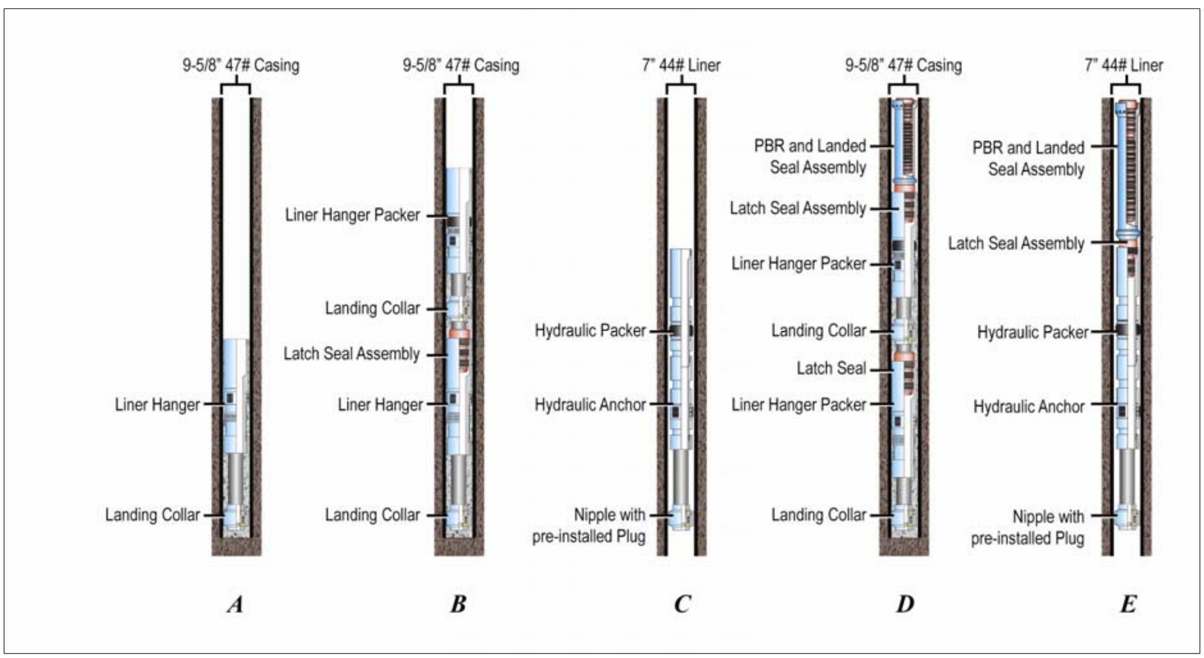

*Figure 2. Operational sequence of geothermal well completion. **A**. Run and cement 7” Liner and 9-5/8” x 7” Liner Hanger. **B**. Run and cement scab 7” Liner and 9-5/8” x 7” Liner Hanger/Packer. **C**. Run and set Hydraulic Packer and Hydraulic Anchor. **D**. Run Seals, PBR and Latched Seal Assembly on a 7” and 7-5/8” tie-back liner. Land seals and tubing hanger. **E**. Run Seals, PBR and Latched Seal Assembly on a 4-1/2” and 5” completion string. Land seals and tubing hanger.*

production packers, liner hangers, liner hanger packers, polished bore receptacles (PBRs), seal assemblies, anchor latches and float equipment for 7" and 9-5/8" casing had to be newly designed, prototyped and tested. The equipment had to be built to withstand bottom hole temperatures of 600°F and pressures of 10,000 psi. The production packer was run on 4-1/2" T-95 21.5 lb/ft tubing and was set in 7" 44 lb/ft T-95 casing. This packer included a cut to release feature. The 9-5/8" liner hanger and liner hanger packer had to set inside 9-5/8" 47# and maintain an ID of 5-7/8".

The testing of the production packer prototype involved setting the tool in the appropriate size and weight of casing as described above. The system was set with the appropriate packer axial setting force. After setting the packer, a differential pressure was held across the system for verification of sealing integrity and then bled off for heating cycle tests to begin. Once the fixture reached the test temperature, a differential pressure was applied to one side of the system and maintained for between five minutes and four hours, depending on the testing requirements. After no leaks were observed, the differential pressure was cycled to the opposite side of the system for the same length of time. With no leaks being observed, the temperature and differential pressure cycle testing was performed three more times. Seals used on the landed seal assemblies and the internal pistons were also tested in dynamic situations. Detailed reports were compiled for each test performed.

The largest challenge to overcome was finding seals that could handle the pressure and temperature as well as real world wear and tear in dynamic situations. To meet the deadline, testing was carried out 24 hours a day, 7 days a week for over two months. While the element testing proceeded quickly as the first element that was tested qualified, finding a suitable elastomer for the landed seal assemblies and internal component seals proved incredibly challenging. Initially, seven different designs from four different suppliers were tested; however, only two passed even the most basic of tests while at temperature. After weeks of further testing and continual improvements and modifications to the seal design, two different styles of seals were qualified from two different vendors. With the most challenging part of the design and testing phase complete, work switched to rapidly manufacturing the actual tools for the job.

<u>Limitations on the Completion Equipment Design</u>

The completion equipment had to meet both a very tight deadline and a demanding set of technical specifications; as such, some tradeoffs had to be made. The liner hangers and liner hanger packers had to maintain a 5-7/8" inside diameter (ID), and after having the material strength de-rated by 20% due to temperature, handle 10,000 psi differential, internal and collapse pressures and over 600,000 lb in tensile loading. They also had to be designed, built and tested in under five months. The main trade-off made was regarding the outside diameter (OD) of the tool. A conventional liner hanger or liner hanger packer for 9-5/8", 47# casing would have an OD of 8.30". The system developed for these wells had an OD of 8.475", resulting in less clearance while running in the hole and less circulation area during the cement job. Prior to the job, the main concern had been with the circulating pressures and because the tool was to be used in a vertical cased hole application, the reduced clearance while running in the hole was thought to be a non-issue. Ironically, it was the reduced clearance while running, coupled with the hausmannite scale, which caused the most issues.

The production packer had similar challenges relating to required ratings and material strengths; however, as there was more flexibility on the ID it was possible to keep the OD of the tool fairly conventional. One challenge was to ensure that if the packer element failed, the slips would remain engaged into the casing. In a conventional, hydraulic-set packer the hydraulic piston pushes into the element, which in turn pushes into the slips. The piston is held in place by a lock mechanism which keeps the required setting force into the packer and element. However, if the element were to fail, it is possible that the slips could relax into the space previously occupied by the element. In a conventional situation, this is incredibly unlikely to happen; however, as this production packer was pushing the envelope in various aspects, it was decided to split the packer from the anchor. The first tool was purely a hydraulic packer with no slips and the second was an anchor with no element. Each tool had its own independent piston and locking mechanism. If the element were to fail with 10,000 psi acting on it while at 600˚F, the completion would maintain its mechanical integrity allowing it to be easily fished and replaced. While this doubled the effective length of the packer and increased the cost, the increased reliability was well worth it.

The second issue with the liner hanger and liner hanger packer was that the system could not be rotated while running in the hole. It was decided early in the design phase that given delivery requirements and the benign well geometry, the ability to rotate the assembly would not be required. The release method for the setting tool was several turns to the right, thereby making right-hand rotation while running in impossible. In hindsight, it appears that this choice created some problems, though by no means would it alone have solved any of the deployment challenges.

Problems Encountered in the Field

The first significant field issue was getting the first liner stuck at approximately 1,300 ft deep due to casing scale packing off around the tool. The vertical well was drilled to a measured depth of 16,075 ft, 9-5/8", casing was set to 12,345 ft and then it was suspended for two years prior to the 7" liner and 4-1/2" completion being run. During that time, a scale composed of hausmannite, an oxide of manganese, formed inside of the 9-5/8" casing covering nearly the entire 12,345 ft.

Even though several full gauge drilling bottom hole assemblies (BHAs) and scrapers were run through the casing, no indications of anything out of the ordinary were seen until the liner hanger was picked up and run. After running in without issues for 13 stands, the assembly became stuck on stand 14 with no ability to move up or down or circulate. After releasing from the hanger and circulating over, five gallons of hausmannite scale were recovered at surface. Two weeks of fishing were required to fish the hanger from the well, after which a casing cleanout BHA was run and rotated over the entire length.

Of all the problems encountered in the field the most severe by a factor of four in terms of days lost, was related to the mud system and hole conditions. The well had a natural fracture that produced both hot water and CO_2. Due to the temperatures, the only mud system that was compatible was a basic water based mud using barite for weight. The constant influx of water made keeping the mud properties under control; however, it was the CO_2 that did the most damage. The CO_2 caused problems both by reducing the pH of the mud system, thereby making it incompatible with the cement job that was to be pumped and, when coupled with the temperature, by changing the mud rheology in very unpredictable ways. In a conventional, lower temperature well there are several different methods to deal with CO_2, but at the higher temperatures the only method available that was compatible with the mud system was to add lime.

As the CO_2 influx was fairly random, and because the delay between adding lime and seeing any result was several hours, correcting the mud rheology and keeping it correct proved a monumental challenge. At various times the mud would be pumped into the hole with all the correct properties and come out looking like chocolate pudding.

The thickening of the mud created circulation challenges on both the completion side and on the reservoir/ geological side. The completion tools being installed were all hydraulically set so the higher the circulation pressures, the greater the chance of pre-setting the equipment. Additionally, the window between the hydrostatic pressure required for well control and the pressure required to open up more fractures was small enough that there was only ~1,000 psi of circulating pressure available. Several attempts were made at trying to run the liner hanger, only to have to pull out due to excessive circulating pressures. Other attempts were made solely with drill pipe and a few joints of 7" liner in an attempt to see if the liner hanger was contributing to the high circulation pressure. On these attempts, the circulation pressures were unchanged, indicating the size and type of liner and liner hanger being run had nothing to do with the pressures. The inability to rotate the liner hanger proved to be a non-issue as, even on these trial runs, rotation in excess of 30 RPM was required to have any measurable affect on the circulation pressures. Therefore, the discarded plans for a rotating liner hanger would never have qualified for that.

After just over four weeks and on the third liner hanger attempt, the liner was successfully run and cemented, at which point the mud issues disappeared. After just over four weeks and on the third liner hanger attempt, the liner was successfully run and cemented, at which point the mud issues disappeared allowing the remainder of the job to progress essentially as per plan.

CONCLUSIONS

Geothermal energy offers a constant and independent supply of power. Accessing geothermal energy is not always easy as deep drilling is required in order to access this high-temperature resource. When combined, drilling and well completions can add up to more than half of the capital cost for a geothermal power project. The industry takes many lessons learned about completion design from the oil and gas arena in an effort to better exploit geothermal resources in developing areas. This paper presented a study of a highly challenging geothermal well in Australia. It focused on the rapid development of fit-for-purpose completion tools and the challenges met and overcome along the way.

REFERENCES

Meixner, A. J. & Holgate, F., 2009. The Cooper Basin Region 3D Map Version 1: A Search for Hot Buried Granites. *Geoscience Australia, Record*, 2009/15. 14p.