PROCEEDINGS, 49th Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 12-14, 2024
SGP-TR-227 SAND2024-01153C

Evaluation of Physics-Based Limiter Redesign Drilling and Alternative Bit Design at The Geysers

Peter So[1], Justin Wriedt[1], Stephen DeOreo[1], Mitch Stark[2], John McLennan[3], Milind Deo[3], Samuel F. Noynaert[4], David Raymond[5], Melanie Schneider[5], Jiann Su[5]

PO Box 5800, Albuquerque, NM 87185

jsu@sandia.gov

Keywords: drilling, PDC, limiter, redesign, geothermal, geysers

ABSTRACT

As part of a U.S. DOE Geothermal Technologies Office funding opportunity, Geysers Power Company, LLC, an indirect subsidiary of Calpine Corporation, partnered with Sandia National Labs, EGI at the University of Utah, and Texas A&M University to demonstrate increased drilling performance at The Geysers Geothermal Field. The performance target in the drilling demonstrations is at least a 25% improvement in rates of penetration with increased time on bottom for each bit. The project will leverage advances in oil and gas drilling technologies including PDC bits, along with the physics-based limiter redesign techniques championed in drilling demonstrations conducted at the Utah FORGE geothermal site. The planned drilling demonstrations are being conducted as part of an existing drilling campaign intended to enhance reservoir utilization. The wells are typically drilled to the top of the reservoir with mud and then air-drilled to total depth (TD) through fractured zones at temperatures ≥ 450°F. A major goal of the project is to assess the effectiveness of implementing mechanical specific energy (MSE) and drilling dysfunction diagnosis and remediation in these challenging environments, as well as alternate bit technologies. The first demonstration well has been completed, with a total of 15 PDC bit runs in the 17.5", 12.25" and 8.5" sections. Initial analysis shows ROP gains in all three hole sections, especially in the 17.5" and 12.25" sections, compared with conventional roller cone bit runs in the demonstration well and offset wells. However in the 8.5" hole, wear and damage to the PDC bits resulted in relatively short bit runs. Analysis is underway to take advantage of the positive results and remediate the challenges.

INTRODUCTION

Current utilization of available geothermal resources is only a small fraction of the potential supply [1]. A primary obstacle to increased use is cost-effective resource development to compete with other resources in the market. Studies estimate the price of geothermal power in the range of $3,000–$6,000 per kilowatt installed [2], largely due to the requirement of developing and securing its fuel source in upfront construction costs. One approach to lowering installed cost is to consistently improve drilling rates and efficiency. Improving drilling rate of penetration (ROP) without sacrificing tool life can dramatically lower well construction time and drive down the cost per kilowatt of geothermal power.

Roller cone drill bits have been used extensively in geothermal applications based on historical performance and convention. Previous drilling campaigns at The Geysers have focused on the use of roller cones as the primary rock reduction technique. Internal data from these campaigns indicate instantaneous rates of penetration in the formations have ranged from 10's-100 ft/hr. The typical duration for reaching 8,000 ft measured depth ranges from 40-60 days. Polycrystalline diamond compact (PDC) drill bits have been tried at various times with limited success whether due to inability to steer or uneven performance.

Combining physics-based practices along with the resources and technology available to the industry, significant performance gains have been made in a variety of oil and gas industry efforts. The same concept translates to geothermal development in high strength, hot rock. Drilling at Utah FORGE has demonstrated the performance gains possible when implementing physics-based, limiter redesign workflows [3, 4]. At Utah FORGE in a relative homogeneous granitoid, within the span of four (4) wells, instantaneous drilling rates were improved by nearly 500% while bit life was improved by nearly 200% (Figure 1).

These gains were made through educating the crews on physics-based drilling concepts and implementing limiter redesign workflows. Although the work leveraged advances in PDC bit technology, as well as directional drilling and drilling fluid vendor tools and resources, the physics-based drilling process was the critical aspect in providing the workflow and framework to understand, implement and maintain last performance gains. In a geothermal field in the Philippines, major gains in performance were achieved by optimizing the design and operating parameters of PDC bits [5].

1 Geysers Power Company
2 Stark Industries Geothermal Resources Consulting
3 University of Utah
4 Texas A&M University
5 Sandia National Laboratories

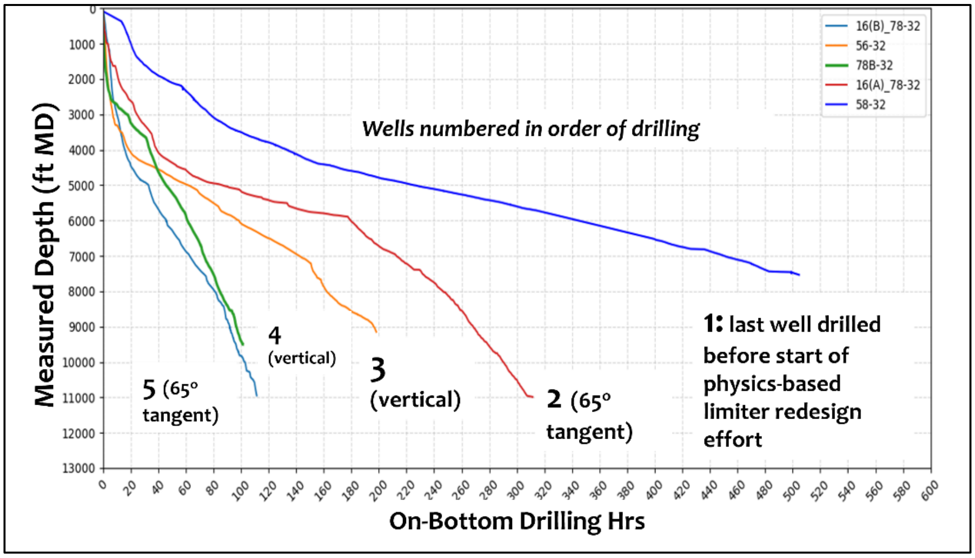

Figure 1. Reduction in on-bottom time in sequential wells at FORGE during physics-based limiter redesign drilling effort. At the same time ROP was increased, bit life in the hard granite was more than doubled.

Geysers Power Company (GPC) is conducting a drilling campaign for several grassroots and workover wells in Sonoma and Lake Counties in northern California. The wells are intended to enhance the generation and utilization of an existing power producing reservoir and are part of an ongoing extensive capital program to sustain reliability and availability for this critical generating facility in California's stressed energy grid. The wells provided an ideal opportunity to demonstrate the potential improvements in drilling rates achievable by using fit-for-purpose bits, improving processes, and identifying performance limiters in a unique geothermal drilling environment.

The long-term goal of the current effort is to establish the framework for implementing limiter-redesign workflows to support process improvements, particularly with respect to drilling operations within the organization. Based on the success of other efforts in the oil and gas industry as well as in geothermal development such as those at FORGE, the goal is for GPC to integrate the limiter redesign approach in the drilling program.

The limiter redesign workflow is agnostic to the rock reduction techniques used for drilling. It is built around understanding the physics of bit performance instead of relying on empirically driven approaches. When the entire drill team understands the physics of drilling, the question becomes what is limiting the application of weight-on-bit (WOB) and/or rotary speed (RPM) at any given time. Armed with knowledge the drill team can then identify and respond to dysfunctions in real-time. In addition, because the physics are understood, the team can also be much more effective when implementing redesign of tools and processes. Redesign may be any number of aspects of the drilling operation but are often focused on the drill bits, bottomhole assemblies (BHA) and drilling fluid. For the project being presented, constraints with regards to BHA and drilling fluid made much of the focus of redesign on the bits, specifically how to transition from roller cone to PDC bits. It should be noted that PDC bits are not necessarily the answer and the other rock reduction techniques such as percussive down-the-hole (DTH) hammers are being explored, and have showed promise in the fractured, air-drilled sections of the well.

The team engaged multiple bit vendors to select commercially available bits that are suited to the formation conditions. This allowed us to assess the state of PDC bits and their suitability for geothermal applications. Maximizing performance will be the objective function.

The current effort is part of a multi-well DOE program aimed at driving down drilling costs and demonstrating the lessons learned and practices employed at Utah FORGE can be extended to any hard-rock environment. This paper will present the results of process improvements employed at the first of two demonstration wells along with the injection of new technology (bit designs, data analysis and system controls) used to help identify and break down process limiters. The first well in this evaluation program is GDC-36, a fairly typical well in the north-central Geysers area that was planned to be drilled to 9,000 ft. Figure 2 shows a map of The Geysers Geothermal Field, with the surface location of GDC-36.

Figure 2. Map of The Geysers Geothermal Field, California, showing the surface location of GDC-36, the first demonstration well for this project.

LIMITER REDESIGN TRAINING

Prior to spud, the GPC drilling team, Kenai rig crews and service personnel, along with the research team participated in a multi-day training session on physics-based drilling practices. The training covered physics-based limiter redesign, with emphasis on physics-based understanding of expected Geysers drilling dysfunctions and how to identify them using electronic drilling records (EDR) data. Emphasis was placed on identifying drilling dysfunctions, and then engineering redesigns to eliminate those dysfunctions. This project followed a traditional physics-based approach where the question is asked of what is limiting the application of additional WOB.

Once a team understands the physics and that in an efficient environment WOB is non-damaging until the structural limit of the bit is reached, the real-time and engineering workflow becomes clear (Figure 3). The wellsite team was taught how to identify dysfunctions in real-time and what can be done in terms of real-time mitigation. If a dysfunction or limiter is identified in real-time and the limits of real-time mitigation practices are reached, the question for the team then becomes what needs to be done in terms of redesign of equipment or practices to increase performance on subsequent runs. By addressing collateral risks and redesigning tools and practices in a physics-based manner instead of empirically, the resulting performance gains will be much more rapid and lasting than those empirically derived.

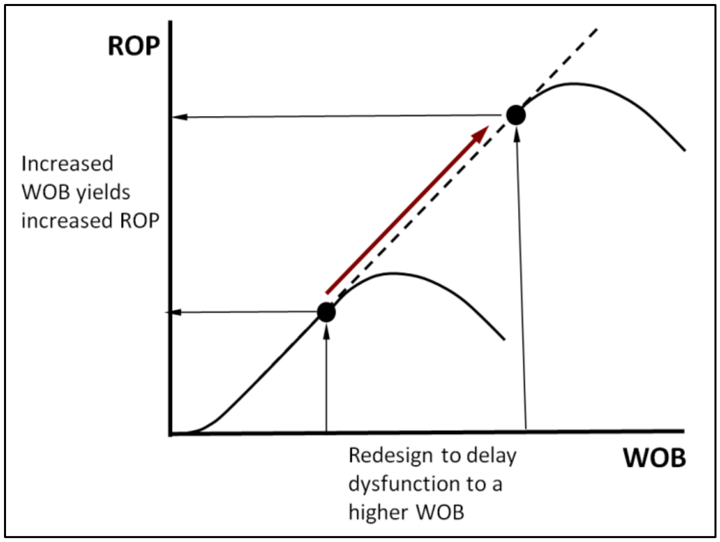

Figure 3. The underlying concept of the physics-based limiter redesign workflow is WOB (or RPM) does not damage bits in an efficient drilling environment. Therefore, a dysfunction or limiter, as seen in a non-linear ROP response or more preferably through a negative MSE (mechanical specific energy) response, indicates where the driller implements mitigation practices if possible, or if not, stop raising WOB until redesign of the system takes place for the next run.

For example, as is discussed later in the paper, the 8 ½" hole section saw the PDC bits encounter what appeared to be large open fractures. The resulting interfacial severity-like damage indicated the WOB as well as the rig control system were limiting the performance both in terms of ROP and run length. In real-time, the rig team tried a variety of mitigation procedures with limited success. The next step in the process is for redesign of tools and practices on the next project well.

The majority of the workflow only requires surface electronic drilling recorder (EDR) data. The key metric used was downhole MSE when using a mud motor in the intermediate intervals and surface MSE when drilling the 8 ½" interval. In this project's case, bottom hole (in-bit measurement sensors) data were collected for all the testing to enable post-drilling analysis of the process and to diagnose the actual limiters being observed.

During the drilling execution, a morning briefing was conducted with the rig crew prior to each shift change. The discussions typically consisted of updates from the previous 24 hours of operation along with the plan for the subsequent 24 hours of operation. Performance limiters such as cuttings removal rates or ability to manage weight-on-bit or torque during drilling were addressed among the team.

DRILLING DEMONSTRATION PLAN

Baseline performance of historic drilling protocols was established through the early drilling campaign wells drilled in the late summer of 2022. Data from these wells, along with other historical drilling data, were used to define the nominal drilling rates and formation conditions in various parts of the play. Instantaneous rates of penetration along with other indicators of drilling performance were documented and evaluated by the team.

The Phase 1 drilling campaign focused on implementing off-the-shelf PDC bits in intervals traditionally drilled by roller cones. While drilling these intervals, periodic trips enabled physically assessing and grading bits and bottom hole assemblies. EDR data were available for offsite post-processing. Each of the project team members analyzed the data as desired to independently assess the drilling performance.

A typical campaign well (Figure 4) completion consists of 30" conductor in a 36" hole drilled to 30'. A 26" diameter hole is then drilled to 500' and 20" casing is cemented to surface. A 17 ½" diameter well is drilled with mud to approximately 2500' with directional work starting in this section. A 13 3/8" casing is cemented to surface in the 17 ½" hole. A 12 ¼" diameter hole is drilled on mud to approximately 5,000' MD where the top of the steam reservoir is encountered. Then, 9 5/8" casing is cemented to surface. The last section of the well is drilled using 8 ½" bit on air to a total depth of 9,000' and completed with a slotted liner and tieback.

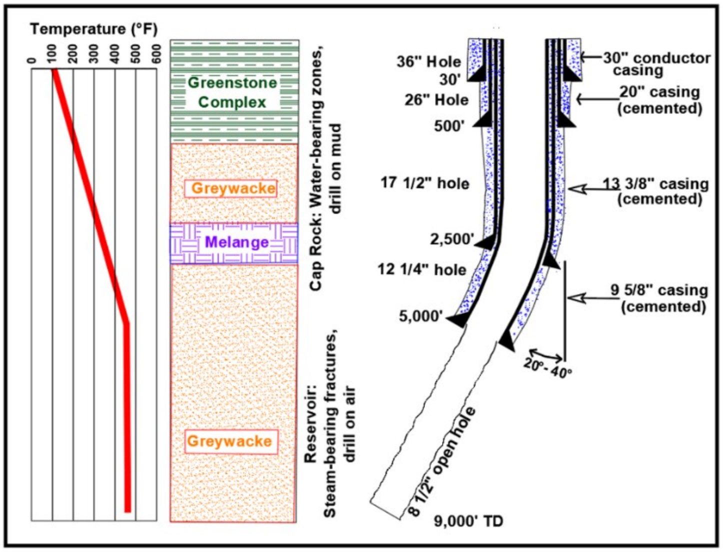

Figure 4. Schematic of a representative Geysers well for the drilling campaign.

Specific to GDC-36, the intermediate 17.5" borehole is drilled from around 430' to around 2,400'. The next interval goes from 2,400' to 3,300' using a 12.25" bit. The final air-drilled section runs from 3300' to 9000'. The team planned to use up to five bits for each of the demonstration zones. The bits included a mix of roller cone and PDC bits and a percussive hammer in the air-drilled 8.5-inch interval. Additional trips for diagnostics and bit replacement were run as required.

Historically, the wells have been drilled using insert bits (aka roller cones). The total expected duration for reaching 9000' including completions is approximately 60-70 days. The goal of the drilling demonstration in well GDC-36 was to incorporate PDCs for the fluid/mud-drilled sections as well as the deeper air-drilled sections.

For each of the demonstration zones (17.5", 12.25", and 8.5"), conventional insert bits were run as along with the PDC bits providing a basis for performance comparison. The target distance for each of the bit runs was 500' in the 8.5" zones with longer distances in the other zones. Bits from multiple vendors were tested to assess the best commercially available off-the-shelf options for PDC bits. In addition to the insert and PDC bits, a percussive hammer, modified for high-temperature, was deployed at the end of the well.

DRILLING RESULTS

The well plan for the first demonstration well estimated approximately 60 days to reach total depth (TD). This included 15 days of drilling and completion in the 17.5" section, 11 days in the 12.25" hole, and 20 days in the 8.5" section. Three intervals were included in the demonstration zone. The actual and planned days vs. depth plot is shown in (Figure 5). The actual days includes time associated with rig repairs and other non-drilling time (NDT). The on-bottom hour reduction when compared to a group of analog offset wells showed significant improvement (Figure 6). It should be noted this representation of drilling performance does not account for run length and other collateral risks which need to be addressed in drilling program. This is particularly true in the 8 ½" hole section where run lengths were quite limited, possibly because of fractures, which create extreme interfacial severity problems.

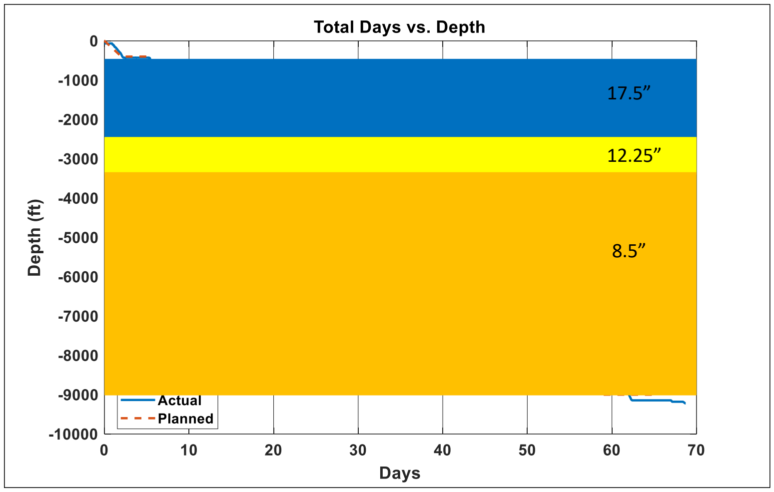

Figure 5. Actual and planned days vs. depth for GDC-36.

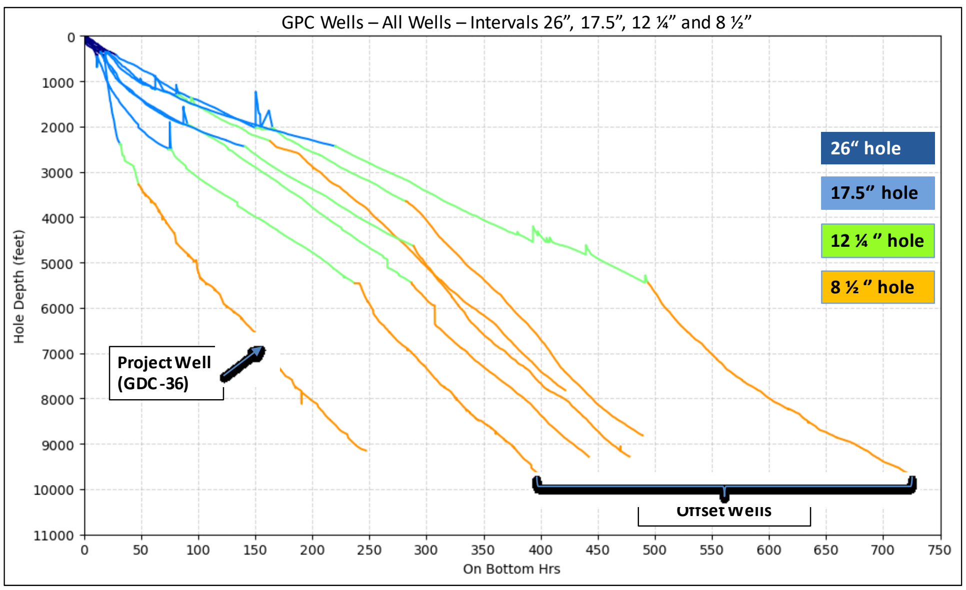

Figure 6. On-bottom hours comparing first project well to analog offset wells. When combined with days vs depth or similar plots, an understanding can be gained of on-bottom drilling performance, off-bottom time (planned and unplanned) and their relationship.

Instantaneous rates of penetration (ROP) at depth are shown in Figure 7. As also indicated by the days vs. depth plot in Figure 5, the fastest drilling occurred in the 17.5" interval. The subsequent intervals presented challenges that resulted in increased total rig time. These included lost circulation zones in the 12.25" section and what are suspected to be fractured zones in the air-drilled 8.5" interval. Although there were drilling challenges in those zones, the improvement in on-bottom performance showed the opportunity and value potential in future wells. For the off-bottom non-bit or BHA limiters and non-productive time events, there were positive lessons learned in how to manage the formation challenges in subsequent wells.

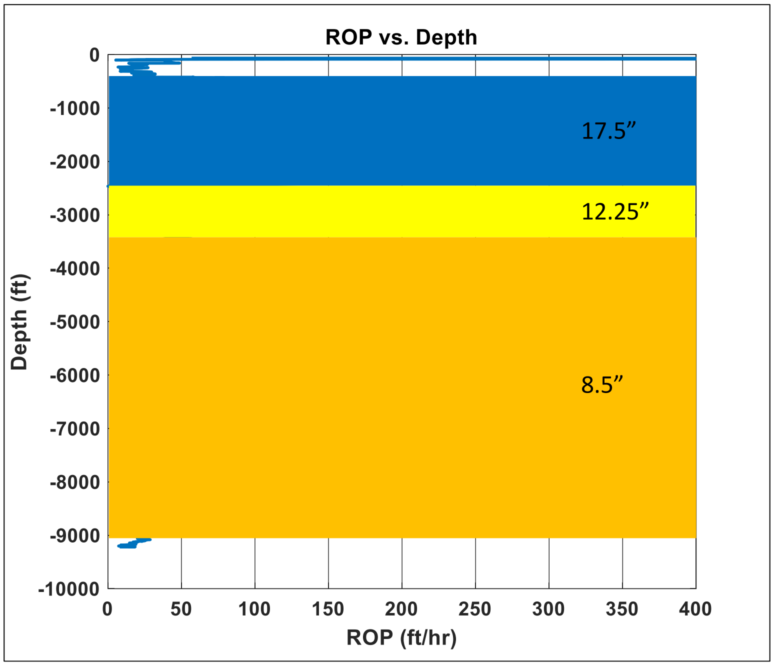

Figure 7. Instantaneous ROP vs. depth for the entire well.

We also analyzed bit run data from GDC-36 and six previous baseline wells (drilled without PDC bits and the physics-based drilling concepts) to get a preliminary idea of performance of the PDC bits vs baseline. Note that the bit run data consist of footage drilled and hours spent per bit run, which includes time for drill pipe connections and possibly other delays while drilling. Therefore, the bit run ROP’s are always slower than the Instantaneous ROP’s discussed above. But the bit run data is readily available from GPC’s drilling database for the baseline wells, so we are using it at this stage to get an early look at performance trends.

Figure 8 shows the baseline vs GDC-36 performance based on bit run data. In the 17.5” and 12.25” hole sections, the performance improvement using PDC bits is unmistakable and impressive, approximately 400% and 700% respectively. In the 8.5” section, performance was about 70% better than baseline, and 50% better than the roller cone runs in GDC-36.

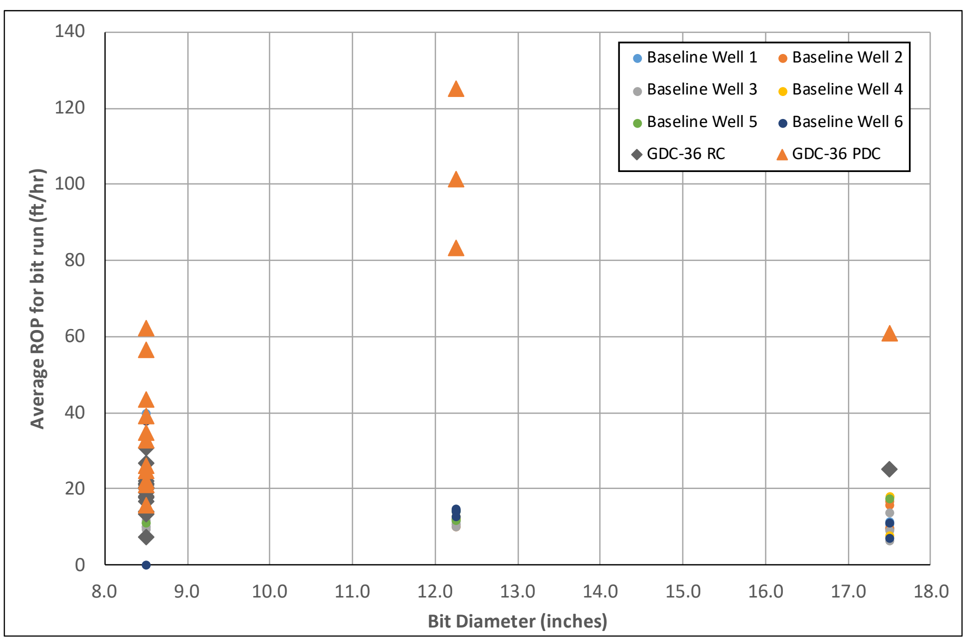

Figure 8. Bit-run ROP for 6 baseline wells, GDC-36 Roller Cone (RC) runs and GDC-36 PDC runs (all intervals).

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Table 1. Tabularized results for baseline wells and GDC-36 bit runs (all intervals).

				ROP (ft/hr)		Bit Runs (ft)		N
Group	**Bit Dia**	**Total Ft**	**Total Hrs**	**Mean**	**Std Dev**	**Mean**	**Std Dev**	**127**
Baseline	17.5"	9,557	811.5	11.8	3.7	683	489	14
GDC-36 RC	17.5"	100	3.5	28.6	N/A	100	N/A	1
GDC-36 PDC	17.5"	2,014	32.5	62.0	N/A	2014	N/A	1
Baseline	12.25"	14,288	1,149.0	12.4	1.4	680	336	21
GDC-36 RC	12.25"	N/A	N/A	N/A	N/A	N/A	N/A	-
GDC-36 PDC	12.25"	941	9.5	99.1	21.1	314	171	3
Baseline	8.5"	27,889	1,494.0	18.7	5.7	372	175	75
GDC-36 RC	8.5"	3,586	169.0	21.2	4.9	299	161	12
GDC-36 PDC	8.5"	2,212	68.5	32.3	14.9	201	154	11

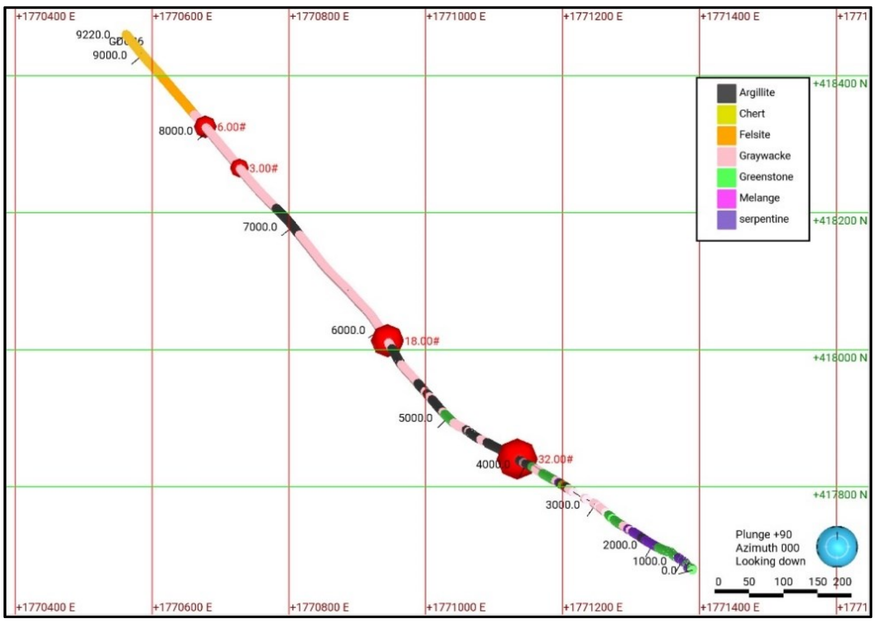

Figure 9. Geologic information for GDC-36

For reference, the lithology for the entire well is shown in Figure 9.

17.5” Interval

The 17.5” interval was drilled using a bent-sub mud motor. The BHA consisted of a conventional bent motor directional BHA with stabilizers on the nose and at the top of the 1.5 deg bend motor. The BHA setup, including stabilization was the standard assembly for the team based on prior experience. The 17.5” interval was drilled from 428 ft MD to 528 ft MD, using an insert bit as a baseline for comparison with the subsequent PDC test runs. A commercial off-the-shelf (COTS) PDC was used to drill the remaining interval to 2,452 ft MD. The average gross overall ROP (including connection times and other off-bottom time) over that interval was approximately 60 ft/hr, with instantaneous ROP generally in the range of 100 to 200 ft/hr in this interval (Figure 10).

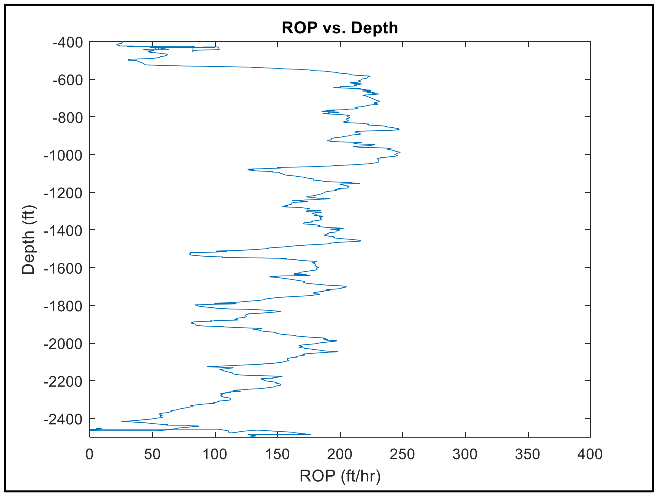

Figure 10. Instantaneous ROP vs. Depth in the 17.5" interval.

Some cutters were sheared off the gage of the bit near the end of the run producing just over 2000 of hole. The overall performance for the application of PDC bits at The Geysers was an encouraging sign for the subsequent intervals. Photographs of the 17.5” PDC bit are shown below (Figure 11).

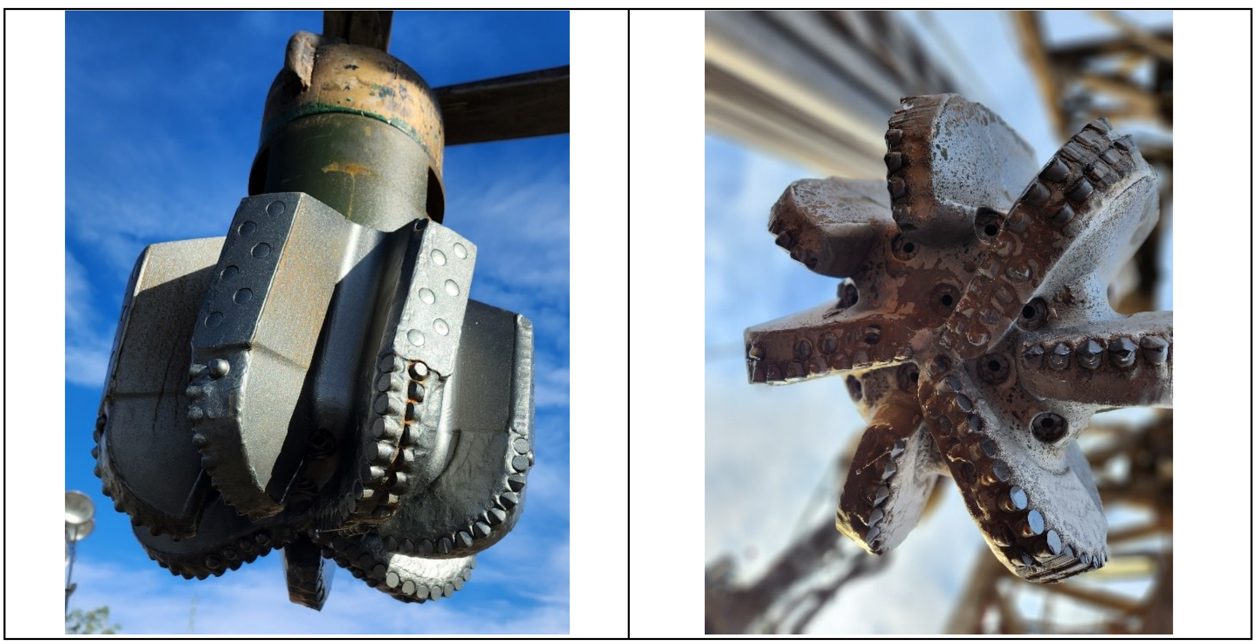

Figure 11. 17.5" PDC before (at left) and after run (at right).

12.25” Interval

The 12.25” was also drilled with a directional BHA and downhole motor. Most directional work occurred in this interval. Based on the superior PDC performance in the 17.5” hole, the team decided to drill the entire 12.25” interval with PDC bits. The interval contained lost circulation zones that were remediated with cement plugs. The plugs had mixed results in preventing lost circulation in the zone. In the end, the team decided to drill through the losses and was able to reach the end of the interval with a combination of insert bits and PDCs. We were unable to execute a single continuous 500 ft run with a bit due to the multiple trips for the cement plugs for lost circulation, a standard practice in the field. The instantaneous ROP vs. depth is shown in Figure 12. Again, during normal drilling, instantaneous ROPs mostly were in the range of 100 – 200 ft/hr for PDC bits. Slower intervals shown in the chart were either due to use of insert bits or control drilling during the lost circulation events and while drilling out cement plugs. Limiters to on-bottom performance were surface solids control capacity, concerns about annular cuttings loading effect on lost circulation and the decision to be conservative with WOB due to these being the first PDC bits run in this interval. Overall, it is clear the focus for drilling time reduction will need to be how to deal with severe lost circulation events and their related risks to the drilling and casing and cementing processes.

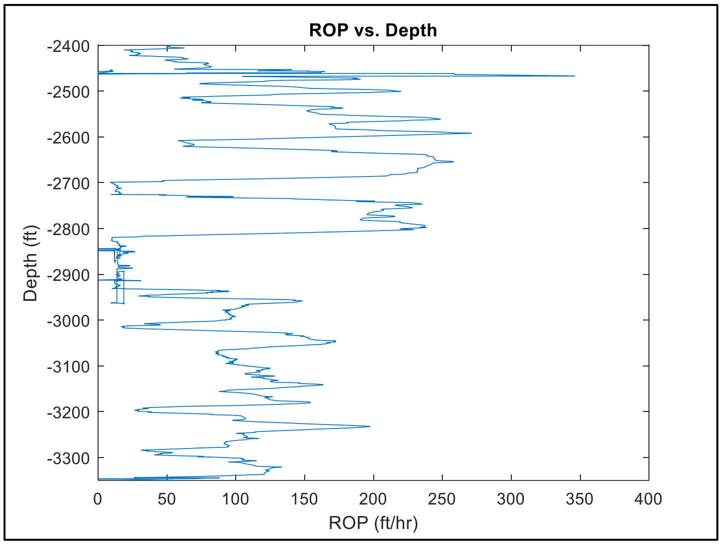

Figure 12. Instantaneous ROP vs. depth (12.25" interval).

Two PDC bits were run in this interval. The first was pulled due to severe loss circulation of approximately 250 barrels per hour after drilling 245 ft to a depth of 2702 ft. The second PDC drilled 94 ft and was pulled due to concerns over high temperatures damaging downhole measurement subs and the need to replace the downhole motor; the same bit was tripped back in and produced an additional 414 ft. Hence this bit produced a combined footage exceeding 500 ft. The two bits are shown in Figure 13. These bits both incorporated shaped PDC cutters – new product offerings for drilling hard rock.

Figure 13. Bit 1 (left) and Bit 2 (right) used in the 12.25" interval.

8.5" Interval

PDC and Roller Cone

The 8.5" interval is arguably the most challenging section of the well since it is air-drilled, fractured, and high-temperature. This is typically air-drilled due to the vapor-static pressure gradient, moisture-sensitive formation, and fractured zones. Additionally, the temperatures in that zone exceed 450°F negating the use of mud motors. The drill string was rotated from the surface using the rotary table. The on-bottom ROP over the interval varied widely depending on the formation conditions and the bit design (Figure 14).

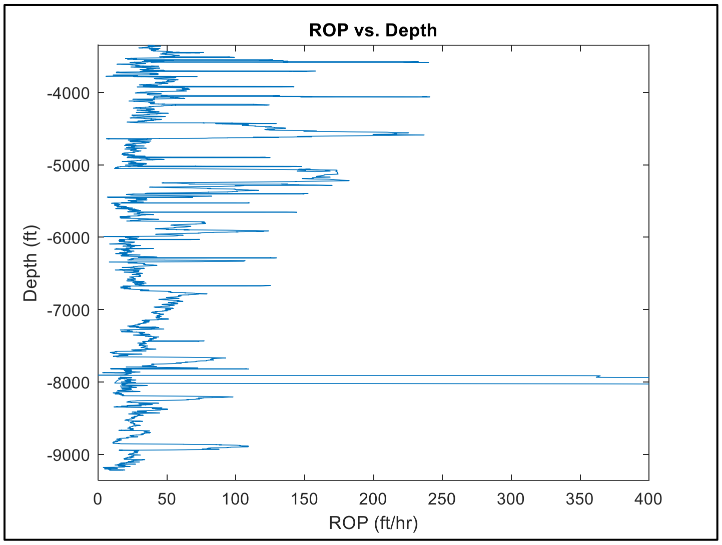

Figure 14. Instantaneous ROP vs. depth (8.5" interval).

Air-drilling is very abrasive on the entire drill string, and typically bits are dulled after less than 24 hours of drilling. With round trips to change bits averaging about 20 hours, bit life becomes a significant value driver in addition to ROP. Figure 15 shows the interval lengths drilled for each bit run in the air-drilled 8.5" hole, for both Roller Cone Insert (RC) and PDC bits. Almost all of these bit runs were terminated because of interfacial severity damage occurring over very short intervals (several feet). Figure 15 shows a wide scatter of bit run lengths. On the average, the PDC bits lasted only 201 ft, while the RCs lasted 299 ft. For comparison, roller cone bit runs in the 8.5" hole in the previous 6 wells averaged 372'. In GDC-36, there also appears to be some correlation between bit life and lithology, with the longest bit runs occurring in the greywacke/argillite intervals, while bit runs were shorter in the mélange, hornfels and felsite intervals. However, the PDC bit dulls showing obvious shearing of cutters indicates the limiter is not a gradual wearing trend seen in some high strength rocks but instead is effectively an instantaneous event. The variability in run length could be due to similar variability in fracture distribution within the reservoir. The bit runs will be investigated in more detail to improve performance in the next project well.

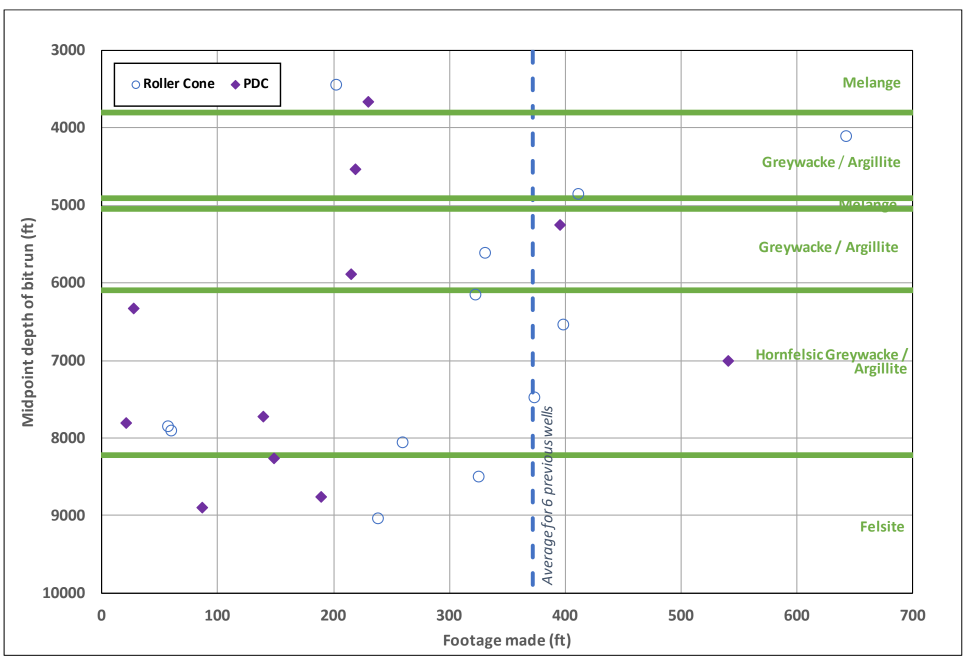

Figure 15. Bit run length vs. depth in 8.5" interval. Geologic units are generalized from Figure 9.

Table 2. Average footage in 8.5" intervals (roller cones and PDC)

Average footage	RC (ft)	PDC (ft)	All (ft)
All rock types	299	201	252
Melange	202	230	216
Gw/Arg	427	277	363
Hornfels	230	182	208
Felsite	282	142	190

The PDC bit penetration rate performance varied throughout the run depending on the formation, the bit cutting structure and the operating conditions. The PDC bit suite for the 8-1/2" section is summarized in Table 3. The penetration rate and footage of the PDC bits comprising the 8½" section is shown in

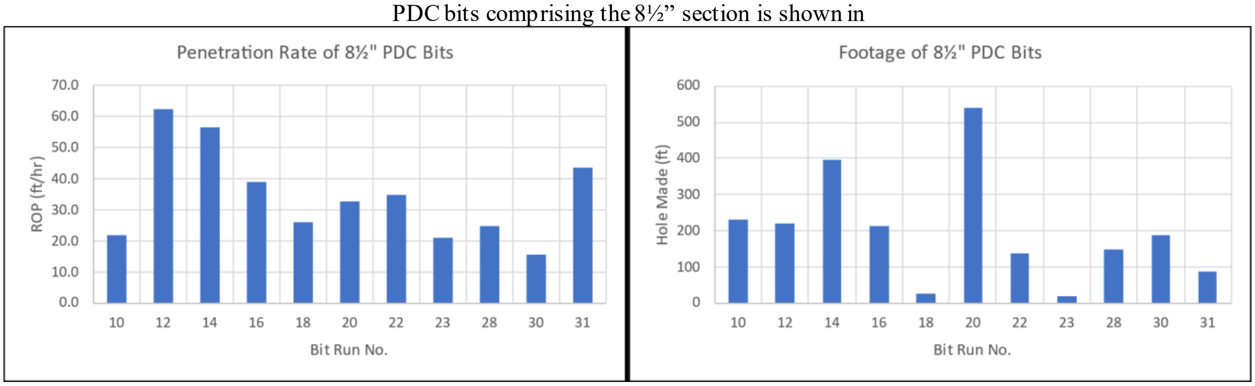

Figure 16.

Table 3. PDC bit suite in 8.5" interval

Bit No.	Depth In (ft)	Depth Out (ft)	Hole Made (ft)	ROP (ft/Hr)
10	3548	3778	230	22.0
12	4421	4640	219	62.3
14	5051	5447	396	56.6
16	5778	5993	215	39.1
18	6316	6342	26	26.0
20	6741	7282	541	32.8
22	7655	7794	139	34.8
23	7794	7815	21	21.0
28	8192	8341	149	24.8
30	8666	8855	189	15.8
31	8855	8943	88	43.5

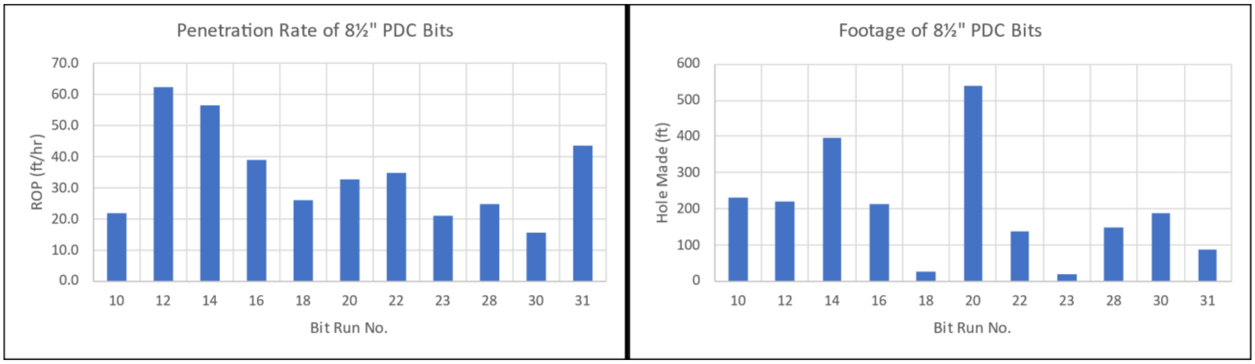

Figure 16. PDC bit performance in the 8 1/2" interval.

Figure 17. Bit 20 before (left) and after (right).

Notably, bit 20 produced 541 ft of hole at an average ROP of 32.8 ft/hr. Pre and post-drill photos are shown in Figure 17. The drilling record for this bit is shown in Figure 18. Remarkably, the cutters performed extremely well in the air-drilling environment.

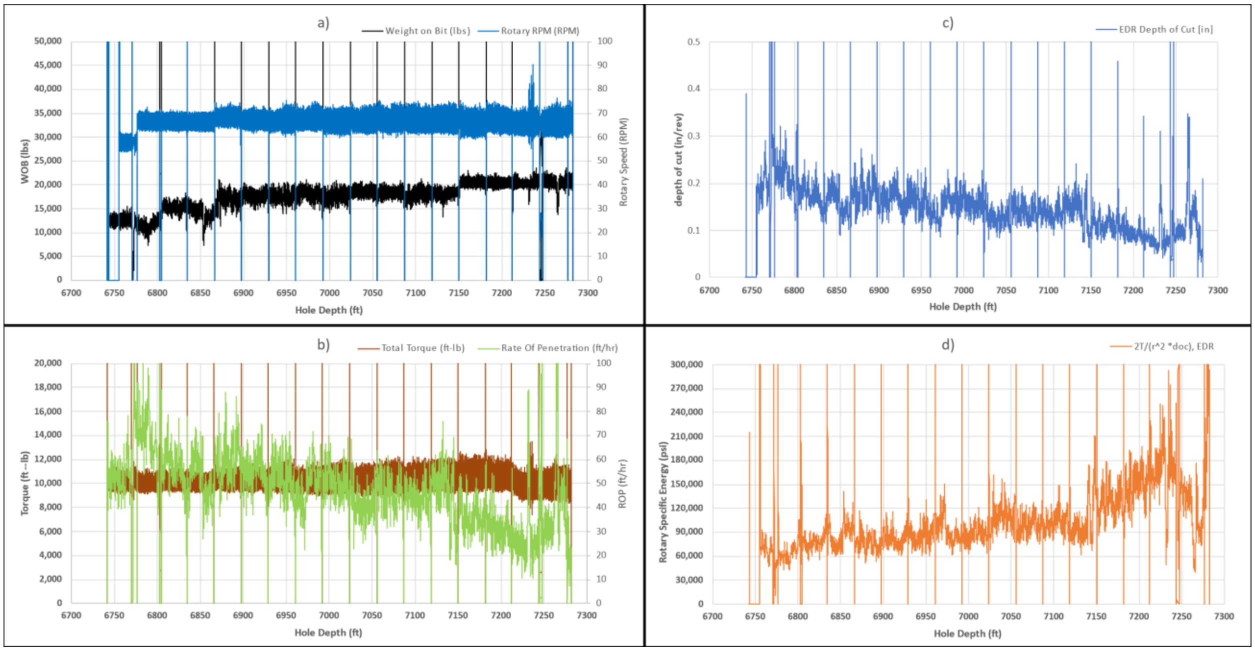

Figure 18. Bit 20 drilling record from one (1) second EDR data including: panel a) Drilling system inputs WOB and RPM (top left) and panel b) drilling system response Torque and ROP (lower left). Also shown are panel c) Depth of Cut per Revolution (top right) and panel d) Rotary Mechanical Specific Energy – important parameters in monitoring PDC bit response.

GDC-36 provides an outstanding case study for air drilling, validating the formulations that have been in the public literature for several decades [6, 7] and that have been honed by substantial practical experience at The Geysers. This data evaluation is ongoing. One of the more interesting aspects of using the PDC bits on air was persistent loss of the bit nozzles, possibly due to significant cooling at the nozzles. The ultimate remedy was to drill without nozzles installed. This is also being evaluated for future operations.

Percussive Hammer (DTH)

Percussive hammers are a promising advanced exploratory drilling technology for geothermal development since they rely on rock reduction mechanisms that are well-suited for use in the hard, brittle rock characteristic of geothermal formations. Down hole hammers are also compatible with low-density fluids that are often used for geothermal drilling. Experience in mining and oil and gas drilling has demonstrated their utility for penetrating hard rock.

Due to timing and availability, the team chose to modify an existing commercial 8” hammer rather than pursue a customized tool for the conditions. The commercial 8” air hammer was modified to allow oil-free, high-temperature operation at the deepest portion of well. The modifications included elimination of elastomeric components as well as lubrication substitution for the conventional rock oil mist.

The hammer was supplied by three air compressors at the surface. The standpipe pressure was approximately 400 psi. There were no measurements of the downhole pressure. When pulled, the hammer and bit were still free to move and there were no visible signs of damage. Before and after photographs of the hammer are shown in Figure 19. The team will conduct an inspection of the internal components before the next demonstration well.

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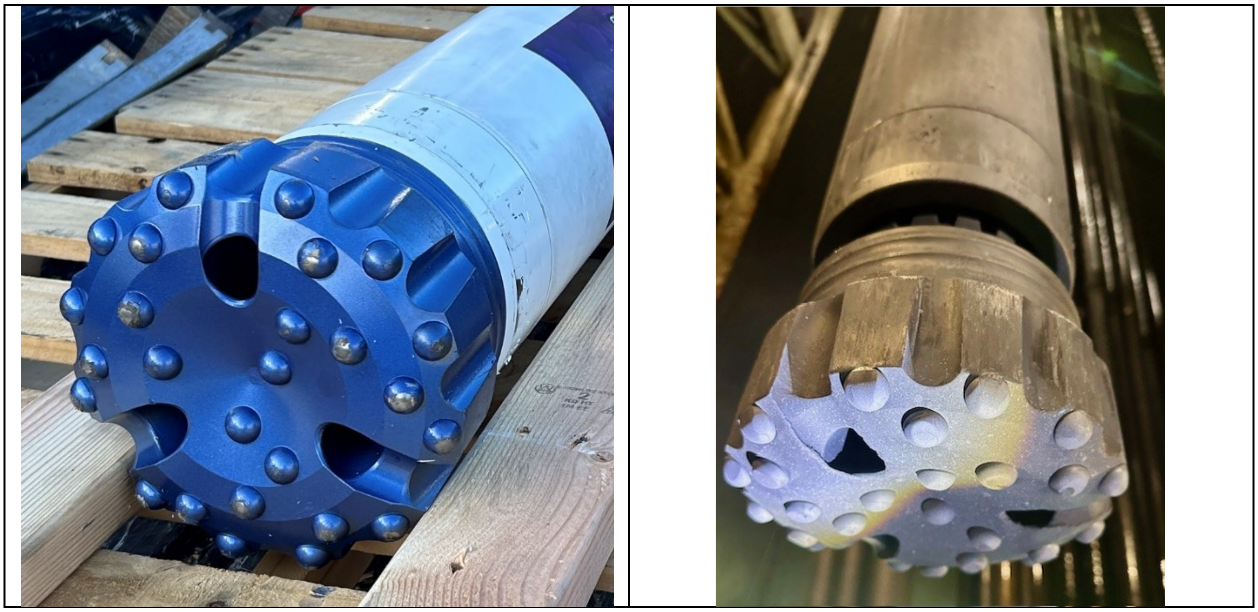

Figure 19. Percussive hammer (DTH) before (at left) and after drilling 40ft (at right).

The hammer was run for 40 ft at the end of the borehole. The drilling performance was heavily influenced by the applied WOB. Early in the run, the team applied between 6-12 klb which resulted in severe torque oscillations (Figure 20). Towards the end of the run, at 9208 ft MD, WOB was relaxed to approximately 2 klb. That reduction in WOB eliminated the torque oscillations and allowed the hammer to achieve nearly 20 ft/hr for the remainder of the run. The hammer was pulled at 9,220 ft to trip for other scheduled operations.

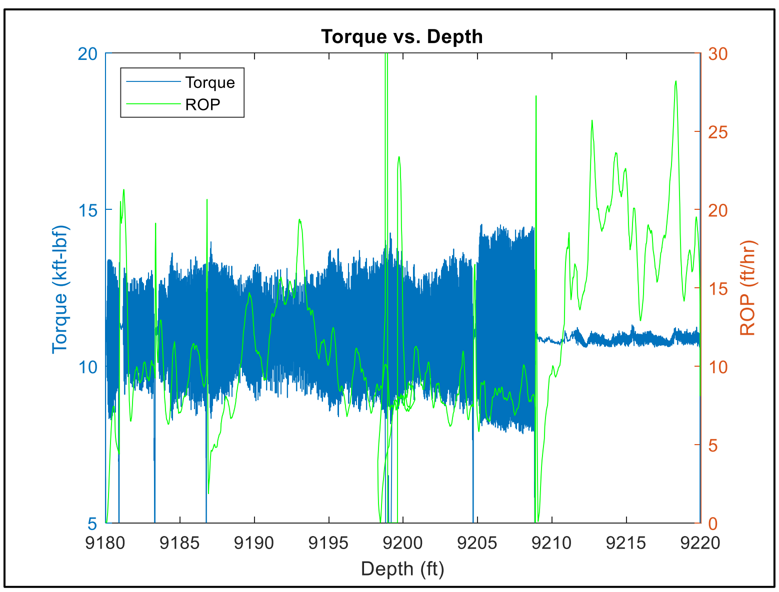

Figure 20. ROP and torque vs. depth with percussive hammer.

BOTTOM HOLE ASSEMBLY (BHA) ANALYSIS

The notion of limiter redesign was also extended to non-bit limiters. Structural modeling of the bottom hole assembly was conducted to identify if there are/were design improvements that could be made to reduce the buckling and vibrational characteristics of the BHA and consequently improve the overall drilling performance. Bottom hole assembly Finite Element Analysis (FEA) was conducted to understand the physical behavior of the BHA under dynamic loading conditions. Two basic tests were conducted to validate the model results. The first test was a static buckling test. This was conducted to determine if there would be benefit to modifying the placement or number of stabilizers in the BHA. The analysis and test were conducted for the 8.5” BHA (Figure 21) but can be extended to the other BHAs as well. The second test was an off-bottom rotational speed test to identify resonant RPM’s of the BHA.

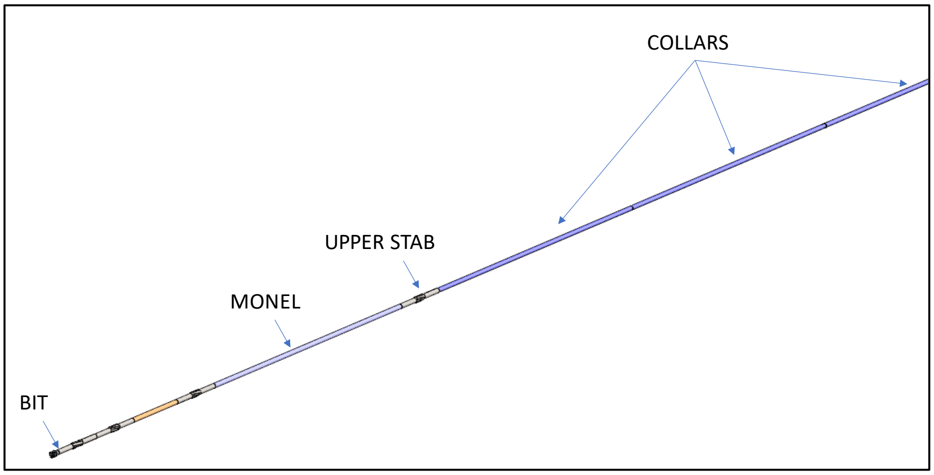

Figure 21. 8.5" Bottom hole assembly (BHA).

The steps for conducting the BHA buckling tests are listed below.

- Lift off bottom
- Add WOB at rate of approximately 10000 lb/min
- Monitor block height (note any jumps in displacement)
- Stop at 40000 lbf
- Repeat test sequence three (3) times

Force data collected from those non-drilling step tests are shown in Figure 22. The block height position from the EDR was used as the displacement sensor for the static test.

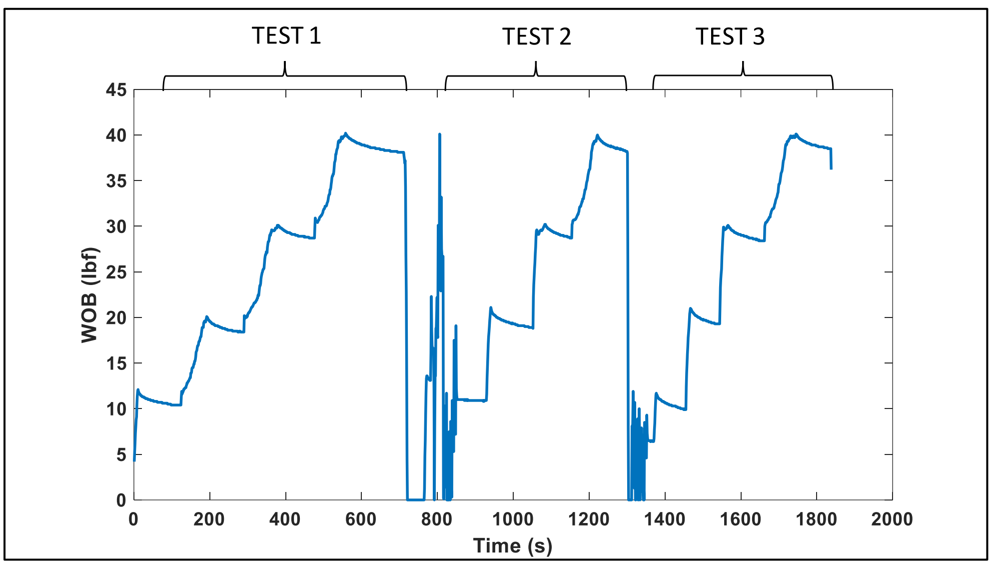

Figure 22. Static weight-on-bit step tests.

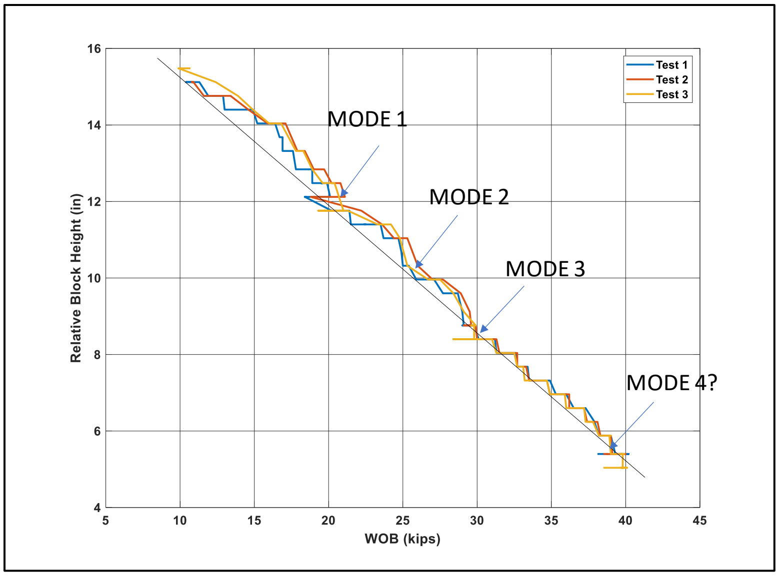

Figure 23. WOB step tests results (WOB vs. block height displacement).

Without buckling, we expect to see uniform displacement with increasing force for the BHA. The BHA is a long-slender beam supported along the length of the pipe through bit/borehole contact and stabilizer/wall contact. Depending on the assumed boundary conditions (e.g. fixed, pinned), the buckling loads can change significantly. The goal of this step test was to determine if we could identify the contact conditions based on the actual buckling loads measured during the test and subsequently change the BHA configuration.

WOB vs. displacement is shown in Figure 23. The test results show nonlinear behavior at multiple points in the load range. The first mode of buckling is at approximately 20,000 lb_f. This coincides with the contact conditions of the bit with the upper stabilizer in contact with the formation. The predicted buckling modes from the ANSYS FEA simulation are listed in Table 4.

Table 4. Predicted buckling loads for 8.5" BHA contact conditions.

Mode	Bit/Free (lbf)	Bit/Upper Stab (lbf)	Bit/Upper Stab/Collar (lbf)
1	16269	20940	28748
2	23894	29482	38956
3	30186	36902	56368
4	36695	49305	74382

REAL-TIME DATA ANALYSIS

Well-site information transfer standard markup language (WITSML) is the standard for transmitting wellsite EDR data to external sources. WITSML was enabled for the GDC-36 operation to support real-time processing of EDR data. Typical EDR displays present time or depth vs. the data of interest. The team is assessing ways to interact with the data that can provide the driller real-time notifications of impending bit damage or other drilling dysfunctions. These responses are intended to counteract acute dysfunction that results in unrecoverable bits or costly BHA damage. WITSML real-time data access will allow the team to develop algorithms to potentially detect drilling dysfunction in real-time and provide an advisory system for the driller on the appropriate response to mitigate those dysfunctions. EDR data was post-processed on GDC-36; the second well will address real-time data analysis for potential drilling process improvements.

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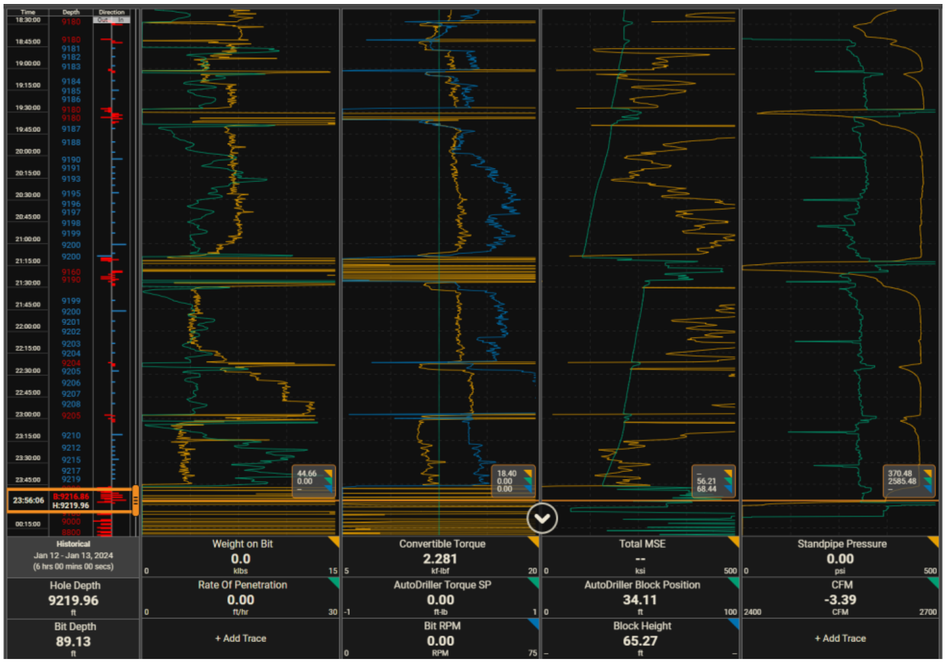

Figure 24. Example EDR data from Pason Data Hub.

CONCLUSIONS

A physics-based limiter redesign workflow was implemented at an injection well drilled at The Geysers geothermal field. PDC bits were deployed in three distinct intervals with unique formation conditions. The first section of the well (17.5") using a commercially off-the-shelf PDC bit performed exceptionally well. Nearly 27 hours of rig time were saved in the 17.5" portion of the hole alone. Aside from the lost circulation zones of the 12.25" interval, the PDC bits responded well to WOB step tests, and the rig team and the research team coordination was well-orchestrated.

Compared to the offset wells, we were approximately 100 on-bottom hours ahead of the next fastest well at the last intermediate hole TD. For the baseline group, we were at a minimum 150 hours ahead of the group average. The experimental effort on a deployed well did not add additional time to the project.

The air section proved to be more challenging using the 8.5" PDCs. One positive result is that PDC cutters did not routinely experience thermal-related failures even at the much higher than normal temperatures for these bits. This was a primary concern at the outset of the project. However, we believe fractures in the formation caused acute, high-torque events, commonly called interfacial severity in oil and gas drilling, which resulted in run-ending damage over very short intervals. The performance opened the door for alternative bit monitoring protocols and WOB procedures to address significant interfacial severity damage.

Additional analysis is being conducted on the large body of data collected during the demonstration. This paper provides a brief summary of the current results and on-going analysis. The team is currently identifying redesigns and process improvements to address limiters that were encountered in the first demonstration well and assessing how to implement those changes in the next demonstration well.

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ACKNOWLEDGEMENTS

We would like to acknowledge the hard work (and understanding) of The Geysers drilling operations team, Kenai rig crew and service providers led by Adam Miller, Rod Bray, Randy Fulcher, Richard Lyons, David Wolff, Brandon McDonald and Curtis Cummings. The team would also like to thank Calpine Corporation and The Geysers Power Company management for supporting this effort.

This material is based upon work supported by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) under the Geothermal Technologies Office Award Number DE-EE0010445.0000.

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