PROCEEDINGS, 51st Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 9-11, 2026
SGP-TR-230

Twinned at 300°C+: High-Performance Geothermal Drilling — Newberry Case Study

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Keywords: Newberry, EGS, well-pairing, field-study, performance optimization, Geothermal Drilling, Well Construction

ABSTRACT

This paper presents the drilling and completion of a closely spaced geothermal well pair in a ~330 °C volcanic reservoir at Newberry. The project demonstrated placement of a new production wellbore (NW55A-29) within ~2 m of the planned trajectory and approximately 90 m from an existing well, enabling controlled hydraulic connection under extreme thermal conditions. System-level integration of BHA design, thermal management, and operational controls reduced on-bottom drilling time by approximately 45% and increased average ROP by 150–300% relative to nearby offset wells. More than 120 cumulative circulating hours above 300 °C were achieved without downhole motor or MWD failures. These results indicate that high-temperature geothermal wells exceeding 300 °C can be drilled reliably using appropriately engineered conventional systems and provide a pathway toward future superhot (>400 °C) developments.

1. INTRODUCTION

High-enthalpy geothermal systems located in volcanic areas, such as Newberry, present unique engineering challenges for deep drilling and completion. These reservoirs often exhibit steep thermal gradients, abrasive lithologies, and aggressive downhole environments where circulating fluids and tool materials are exposed to temperatures >300 °C. These conditions exceed the thermal and mechanical design envelopes of most currently available conventional oil-and-gas drilling systems. The development of high-temperature drilling technologies therefore plays a critical role in unlocking superhot geothermal resources capable of producing supercritical and high-enthalpy fluids.

Previous geothermal drilling operations reported substantial tool degradation, rapid bit wear, and unplanned non-productive time (NPT) due to thermal failure of elastomers, dulling of the bit cutting structures, and loss of drilling efficiency. While material-level advances remain important, field results from these wells demonstrate that system-level integration for well construction is required. Elements such as optimized BHA design, conservative motor RPM, thermal circulation management, and operational discipline can deliver step-change performance even with largely conventional tools and materials.

This paper documents the framework and field application of a twinned high-temperature Enhanced Geothermal System (EGS) completed in Oregon. Specifically, it details the successful drilling and completion of a new production well (55A-29) placed within 90 ± 2 m of an existing wellbore (NW55-29). By leveraging system-level integration, including high-inertia BHA design, conservative motor RPM management, and validated thermal-mechanical modeling, the project achieved the expected performance, including an approximately 45% reduction in on-bottom drilling and zero downhole tool failures despite cumulative exposure to temperatures exceeding 300°C.

2. GEOLOGICAL SETTING AND HISTORICAL DRILLING CHALLENGES

Newberry Field is in central Oregon, approximately 35 km southeast of Bend. Subsurface investigations and geophysical surveys indicate a substantial magmatic heat source beneath the caldera, driving a high-temperature geothermal system with gradients >110 °C/km in localized zones. Lithologic logs from previous drilling campaigns (e.g., DOE-funded Newberry Deep Drilling Project, NDGP) reveal a stratigraphy characterized by:

- 0–500 m: Unconsolidated volcanic ash and pumice interbedded with basaltic lava flows.
- 500–1,500 m: Dense basaltic and andesitic flows with frequent brecciation.
- >1,500 m: Welded tuffs, intrusive dikes, and hydrothermally altered zones of varying permeability.

Measured temperatures in existing wells (e.g., NW55-29) exceed 330 °C at depths of approximately 3 km, placing these wells among the hottest accessible geothermal systems in the continental U.S. The high-temperature gradient, combined with low natural permeability, presents both opportunity and challenge; the abundant heat for supercritical resource potential, but severe conditions and challenges for drilling tools and materials, and fluid systems.

Geothermal exploration at Newberry began in the 1970s with shallow gradient wells, followed by multiple deep wells drilled under DOE and private-sector partnerships. Earlier campaigns utilized conventional oilfield drilling assemblies and encountered persistent problems, including:

- Accelerated bit wear due to hard, abrasive lithologies.
- Loss of tool integrity above 280 °C.

- Circulation losses in fractured zones.
- Elevated torque and drag during tripping operations.

In addition, the lithologic sequence at Newberry, dominated by dense basalts and andesites presents extremely high unconfined compressive strengths and abrasive crystalline textures. Traditional roller-cone and PDC bits suffered from rapid cutter wear, spalling, and loss of integrity when exposed to sustained high temperatures. ROP typically drops by an order of magnitude after the first few hundred meters of drilling in high-temperature, hard-rock zones. Heat generation at the bit–rock interface exacerbates these issues, accelerating binder softening in PDC cutters and carbide oxidation in inserts. Without sufficient cooling or thermal-resistant materials, bit life can be reduced to less than 10% of the design target achieved under moderate-temperature conditions. This highlights the necessity for optimized PDC bit designs for igneous formations, which have demonstrated significantly improved ROP and durability in volcanic environments (Tipples et al., 2024).

3. TWIN WELL DESIGNS AND OVERALL CAMPAIGN

The campaign was an integrated twin-well program with two sequential phases:

1. Repurposing, recompletion, and stimulation of the deviated existing well (NW55-29) to serve as an injector.
2. Drilling, completion, and stimulation of a newly drilled parallel well (NW55A-29) designed as the producer.

Operations were conducted between October 2024 and June 2025 using a 2,000-hp land rig. The twin-well concept required precise lateral spacing to enable controlled hydraulic connectivity in the 330°C reservoir. The primary objective was to demonstrate that a new production well could be drilled within a narrow tolerance of a legacy wellbore at extreme temperature, enabling fracture connectivity during stimulation. Secondary objectives included validating and de-risking drilling, casing, cementing, and stimulation technologies for future well construction in superhot rock conditions.

Existing Well History and Completion (NW55-29 Well)

Well NW55-29 was drilled in 2008 as an exploratory well targeting high-temperature volcanic formations. The well reached a total measured depth of 10,060 ft MD (3,066 m) and was constructed with surface and intermediate casing strings terminating in a 9⅝-in. liner set from approximately 4,199 to 6,462 ft MD. Below the liner shoe, the reservoir interval was drilled as an 8½-in. open hole to total depth. During drilling, formation temperatures exceeded 300 °C below ~9,000 ft MD, significantly degrading wireline logging performance and limiting early reservoir characterization. Initial injection testing indicated minimal injectivity, and the well was therefore preserved in a suspended configuration rather than completed for production or injection service. The final original completion resulted in 9⅝-in. liner tied back cemented.

Subsequent re-entry and cleanout operations enabled recompletion of the lower wellbore using perforated 7-in. liner sections installed in multiple stages from approximately 6,220 ft MD to near total depth, with a 4.5in. liner hanger set at ~7,500 ft MD. Partial liner recovery during later interventions left residual 7-in. liner sections in situ, reducing effective internal diameter and constraining direct access to the deepest reservoir interval. Despite these geometric constraints, pressure integrity of the wellbore was maintained.

Thermal measurements collected during drilling and subsequent workover operations confirmed a steep geothermal gradient, with a maximum recorded temperature of ~332 °C near total depth. Formation integrity and leak-off testing conducted at multiple stages in the well's lifecycle indicated fracture gradients ranging from 0.86 to 1.03 psi/ft, establishing boundary conditions for casing load analysis and stimulation pressure design under superhot conditions.

In 2024-2025 a workover campaign was initiated to convert Well NW55-29 into a dedicated injector for a superhot EGS. The workover strategy prioritized verification of pressure integrity, recovery of usable reservoir access, and preparation of the wellbore for high-pressure injection (>10,000 psi surface-equivalent) at temperatures >300 °C. Operations included extensive cleanout and casing scraping, liner and fishing and milling.

These operations restored access to near-total depth (~9,990 ft MD) despite the presence of legacy liner sections and cement interfaces. Post-workover pressure and formation integrity testing confirmed the well's suitability for high-rate hydraulic stimulation in basaltic and granodioritic formations. The final completion configuration provided a continuous, pressure-rated flow path capable of accommodating high injection pressures and repeated thermal cycling, despite the complex casing history.

Overall, the repurposing of Well NW55-29 demonstrated that legacy geothermal wells with non-ideal mechanical configurations can be effectively repurposed for superhot EGS applications when pressure integrity, fracture gradient limits, and thermal loading are treated as primary design constraints. The well now functions as a dedicated injector and provides a quantitative reference case for integrating existing geothermal infrastructure into future developments targeting reservoirs in the 300–350 °C temperature range.

Twin Well Design, Drilling and Completion (NW55A-29)

The NW55A-29 well was drilled during the same campaign, as a production well, in a closely spaced twin-well configuration with the legacy injector (NW55-29). The well was designed as a critical component of a pilot EGS program to demonstrate engineered reservoir creation and sustained heat extraction in a superhot environment with temperatures ~330 °C. The twin-well configuration was selected to intersect and hydraulically connect with the previously stimulated reservoir volume associated with legacy well NW55-29, thereby enabling controlled circulation and heat harvesting between injector and producer.

The primary objectives of the NW55A-29 well were to:

(1) Drill and complete a high temperature well without health, safety, or environmental incidents.
(2) Successfully parallel the existing Well NW55-29 with sufficient positional accuracy to enable post-stimulation hydraulic communication.
(3) Validate directional drilling performance, well construction integrity, and downhole measurement reliability under extreme thermal and mechanical conditions.

In addition, the well served as an opportunity for testing advanced and in-development drilling technologies, which included shaped PDC cutters, two-phase drilling, and high-temperature-rated BHAs, all intended to de-risk future commercial-scale EGS development in superhot rock settings.

NW55A-29 well reached a total MD of 10,200 ft (3,109 m), penetrating a stratigraphic sequence dominated by basaltic flows, welded tuffs, and granodioritic basement lithologies across the reservoir interval. Drilling operations confirmed the feasibility of maintaining directional control and borehole stability in hard, abrasive volcanic and crystalline rocks at elevated temperatures. The well was completed with a casing and liner program specifically engineered for high-temperature service, with cementing and well control practices adapted to mitigate loss circulation, thermal expansion, and phase-change-related flow behavior.

The drilling and completion results from NW55A-29 well provides a foundational dataset supporting the technical and economic viability of superhot rock EGS concepts being advanced at Newberry and similar high-enthalpy geothermal systems, by implementing an integrated well design, stimulation, and diagnostics strategies to manage uncertainty and risk (Grubac et al., 2024).

Derisked EGS Well Construction for Producer Well NW55A-29

Well construction strategy implemented for the producer well demonstrates a derisked approach to EGS development. The design integrates advanced casing engineering, thermal management, and operational validation to address the coupled mechanical and thermal challenges inherent to SHR geothermal wells. Rather than relying on conservative assumptions or single-point design criteria, the well was constructed using a reliability-based methodology that accounted for casing and tubular loads across all phases of operation, including drilling, cementing, stimulation, and well testing.

An advanced casing design methodology was applied to ensure structural integrity under extreme thermo-mechanical loading. The integrated casing design approach reduced calculated peak casing stress by approximately 20–25% relative to the baseline design All casing strings were cemented to surface, providing full-length mechanical support and redundancy against thermal cycling–induced damage. Cement systems, including foam cement and lightweight slurries, were tested and deployed to accommodate high-temperature conditions while maintaining placement reliability. Circulating temperature reduction strategies and rebound time characterization were incorporated into cementing operations to ensure that cement placement temperatures remained within validated performance envelopes. Specialized float and shoe equipment rated for elevated temperatures were also qualified and deployed, reducing the risk of downhole equipment failure during critical cementing operations.

The validated combination of advanced casing design, temperature-managed drilling, and reliable cementing practices provides a scalable framework for multi-well field development. Lessons learned from this well indicate that further improvements in drilling performance could reduce drilling time by approximately 20–30% in future wells, materially improving capital efficiency and accelerating commercial deployment of high-temperature geothermal resources.

4. DRILLING SYSTEM DESIGN AND OPERATIONAL PROTOCOL

The record performance achieved in the NW55A-29 well was the result of an integrated systems-engineering approach, focusing on four key pillars: BHA design, thermal management, precision well placement, and bit selection. This methodology prioritized operational discipline and the synergistic interaction of largely conventional tools over reliance on unproven exotic materials.

Bottom Hole Assembly Design and Reliability

Developing a drilling system capable of continuous operation beyond 300 °C requires a re-examination of nearly every component of the bottomhole assembly (BHA). Developing reliable high-temperature instrumentation remains a parallel challenge for any superhot geothermal drilling program, as effective process monitoring is indispensable for both performance evaluation and safety assurance.

Measurement-while-drilling (MWD) and logging-while-drilling (LWD) tools rely on electronic components that rarely tolerate >200–225 °C. Above these limits, sensor drift, insulation failure, and electronic breakdown preclude real-time data acquisition. This loss of downhole telemetry restricts optimization of drilling parameters in situ, forcing reliance on surface data and empirical control—an operational constraint that drives both cost and uncertainty.

Cumulative circulating exposure above 300 °C exceeded 120 hours, with zero downhole motor or MWD failures. In contrast, offset wells historically averaged two downhole tool failures per well, resulting in approximately five days of non-productive time (NPT). This reliability was achieved using high-inertia BHAs (9½″ and 8″ collars), conservative downhole RPM management, even-wall motors, and disciplined auto driller control strategies. Notably, torsional vibration was effectively mitigated through mechanical design alone, without reliance on stick-slip mitigation software.

Thermal Management and Hydraulics Modeling

A validated thermal-mechanical model was used to predict downhole temperatures in real-time based on circulation rates, fluid properties, lithology, and operational parameters.

To manage wellbore temperatures, we implemented:

- Pre-Cooling Circulation: Extended circulation periods prior to tripping or connection to reduce the average wellbore temperature.
- Optimized Flow Rates: Circulation rates were carefully balanced to ensure adequate hole cleaning while minimizing frictional heating.
- Fluid Properties: The drilling fluid was treated with high-temperature stabilizers and loss circulation materials (LCM) tailored to the expected fractured zones.
- Insulated drillpipe segments in the lower BHA to minimize upward heat transfer.

This proactive thermal management was the cornerstone of achieving over 120 hours of circulation above 300°C with zero MWD or motor failures.

Precision Well Placement

Well placement and trajectory control were achieved with high precision despite the challenging drilling environment. This performance is consistent with the producer-well planning and execution framework described by Grubac et al. (2026), where stimulation-driven well placement, uncertainty-ellipse management, and survey error control were identified as critical enablers for successful EGS connectivity.

Directional accuracy was maintained within approximately 2 m, enabling tight parallel well placement and demonstrating the feasibility of future multi-well and lateral development. Trajectory control was sustained under high-temperature and hard-rock conditions, confirming the robustness of the BHA design and directional drilling approach.

Achieving the 90± 2 m spacing requirement demanded advanced directional control and surveying. Multiple gyro surveys were utilized to provide accurate, magnetic-independent surveys in real-time also being conducted. As per expectations, these were unaffected by the magnetic interference of the nearby existing wellbore, or magnetic nature of the formations. The directional plan was designed with smooth well paths to minimize torque and drag. The combination of the stable BHA, precise surveying, and real-time monitoring allowed for continuous steering corrections, resulting in the final confirmed placement within the tight target tolerance.

Bit Selection and Performance

The campaign utilized optimized PDC bit designs specifically engineered for igneous formations. The deployed PDC bits incorporated several key features identified by Tipples et al. (2024) as critical for durability and performance in volcanic drilling environments, among those:

- Advanced Cutter Technology: Thermally stable diamond cutters with deep cobalt leaching and enhanced abrasion resistance, reducing susceptibility to thermal degradation and wear in high-energy drilling conditions.
- Robust Hydraulics: Optimized nozzle sizing and placement to maximize cutter cooling and cuttings evacuation at the bit face, directly mitigating heat buildup at the cutter–rock interface, a primary failure mechanism in igneous formations.
- Durable Matrix Body: A body design resistant to erosion and impact damage, supporting sustained performance in vibration-prone, interbedded lithologies.

In the drilling of the NW55A-29, these design choices enabled sustained high rates of penetration (80–100 ft/hr) through competent basaltic and andesitic intervals, substantially exceeding historical offset performance and confirming the applicability of modern PDC technology for deep, high-temperature geothermal wells. Specifics of the bit design philosophy and subsequent field-performance analysis is presented by Tipples et al. (2024).

5. OPERATIONAL PERFORMANCE

The drilling program was focused on countering three main challenges: thermal exposure (>330 °C), directional uncertainty, and downhole tools survivability. As a result, the well design prioritized controlled dogleg severity, vibration mitigation, and thermal management over aggressive ROP targets. A staged hole design comprising four primary sections (26 in., 17½ in., 12¼ in., and 8½ in.) was implemented to manage drilling dynamics and cumulative thermal loading.

Directional control was achieved using positive displacement motors (PDMs) with slide–rotate drilling. Rotary steerable systems were excluded due to temperature limitations, expected steering degradation in basaltic formations, and electronics survivability. Dogleg severity was intentionally limited to approximately 2.5° per 30 m, which proved sufficient to maintain trajectory while minimizing torque, drag, and elastomer degradation.

The upper hole sections were drilled through fractured volcanic formations characterized by localized losses and mechanical instability. In the 17½-in. and 12¼-in. sections, drilling performance was strongly influenced by torsional and axial vibration. To mitigate these effects, stiff, high-inertia BHAs with optimized stabilizer placement were employed. Operational data show that vibration mitigation, rather than bit aggressiveness, was the primary driver of drilling efficiency in these intervals. Optimized PDC bits achieved sustained ROPs exceeding offset benchmarks despite increasing formation strength.

The transition into superhot conditions occurred below approximately 9,000 ft MD, where formation temperatures exceeded 300 °C and approached 330–332 °C near total depth. The 8½-in. production section, drilled from this depth to TD. Thermal exposure became the controlling design parameter, directly influencing survey frequency, circulation schedules, and tripping practices. Thermal modeling was used to predict downhole temperature rebound, and static time was minimized to maintain MWD electronics within survivable limits. These controls enabled reliable directional surveys and toolface control, and no downhole tool or electronics failures were recorded during drilling.

Despite the extreme environment, drilling performance in the production interval remained consistent. Average ROPs of approximately 70 and 80 ft/hr were achieved, with peak values exceeding 100 ft/hr in competent igneous rock. Single-run PDC bit footage exceeded 2,700 ft, demonstrating that bit durability and thermal management were the dominant performance constraints. Analysis of time-depth and performance data indicates that improved thermal management and BHA standardization could reduce drilling time by 20–30% in future superhot wells.

Well placement accuracy was a primary success criterion. The final trajectory achieved a planned center-to-center spacing of 90 m, with an achieved separation of 90 ± 2 m relative to NW55-29 well, as confirmed by directional surveys. Over the parallel reservoir interval, positional deviation remained within approximately 6 ft (~1.8 m) of the planned trajectory. This level of accuracy was achieved despite magnetic noise, survey uncertainty, and vibration-induced measurement degradation.

All casing strings were cemented to surface using high-temperature cement systems, including foam and lightweight slurries selected to balance placement reliability with thermal performance. Circulating temperature behavior was monitored during cementing to validate placement assumptions, and high-temperature-rated float and shoe equipment were successfully deployed. Post-cement evaluation confirmed casing integrity and cement stability under elevated thermal and pressure conditions, establishing a completion envelope suitable for subsequent stimulation and production testing.

Drilling and Tripping Performance

The drilling and tripping analysis demonstrated balanced time allocation between hole construction and pipe-handling activities. Rotary drilling dominates drilling operations, indicating effective drilling practices, while tripping time, driven primarily by connections, represents a comparable operational demand. Optimization efforts focused on tripping efficiency and connection time reduction may yield measurable improvements in overall well delivery performance.

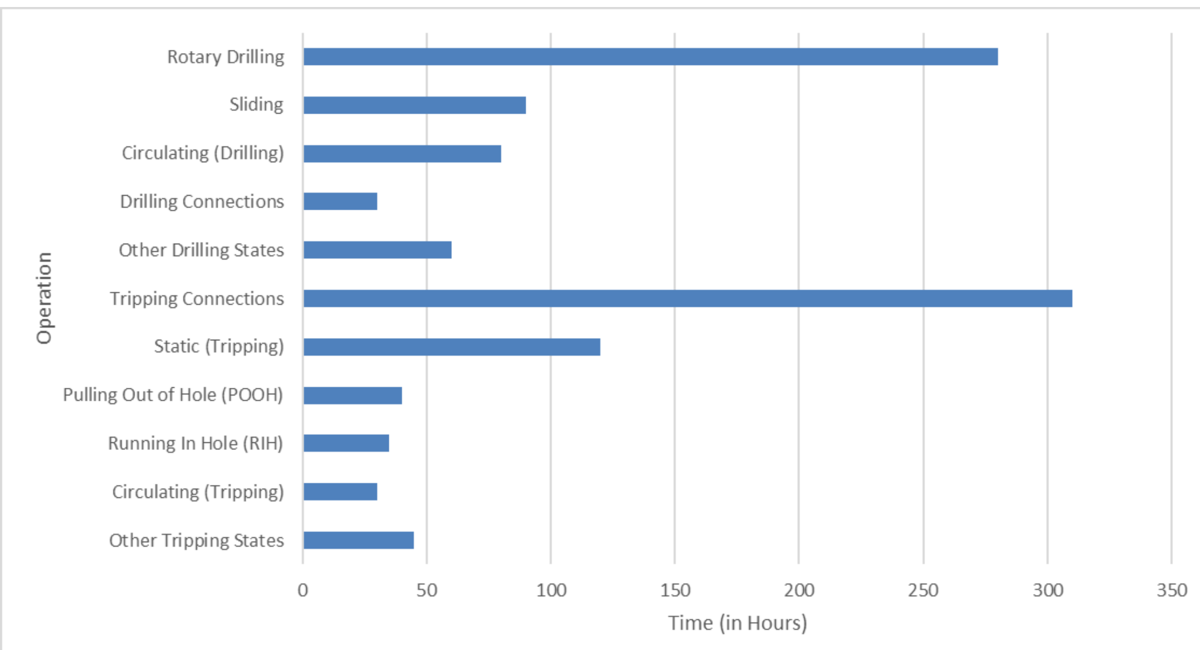

Figure 1 - Time allocation for drilling and tripping activities for Well NW55A-29

Within the Drilling category, time allocation was dominated by rotary drilling operations:

- Rotary drilling: 281.28 hours (52.1% of drilling time)

- Sliding drilling: 87.27 hours (16.2%)
- Circulating: 80.40 hours (14.9%)
- Connections: 28.84 hours (5.3%)
- Static, reaming, washing, and unknown: collectively 11.5%

The predominance of rotary drilling suggests favorable drilling conditions and effective bit and bottom-hole assembly selection. Sliding time remains moderate relative to rotary drilling, indicating manageable directional control requirements and stable trajectory execution. Circulating time represents a meaningful portion of drilling activity, likely reflecting hole-cleaning demands associated with depth, cuttings transport, or formation characteristics typical of geothermal drilling environments.

While tripping time was substantial, a closer look revealed that it wasn't due to inefficiencies, but the time spent on trips were a consequence of well depth and complexity of thermal management. Tripping operations accounted for more time than drilling time. The breakdown of tripping activities is as follows:

- Connections: 313.82 hours (54.2% of tripping time)
- Static: 109.68 hours (18.9%)
- Pulling out of hole (POOH): 41.34 hours (7.1%)
- Running in hole (RIH): 39.76 hours (6.9%)
- Circulating: 31.60 hours (5.5%)
- Washing, reaming, and unknown: collectively 7.4%

Connection time represents the dominant component of tripping operations, accounting for more than half of total tripping time. This distribution is consistent with deep or extended wells where frequent connections, long pipe strings, and handling constraints significantly influence operational efficiency. Static time during tripping may reflect waiting periods, equipment handling, or operational coordination between pipe movements.

Real-time Optimization

Real-time drilling optimization resulted in consistent and substantial performance improvements across all hole sections when compared with offset geothermal wells drilled in similar lithologies. Average ROP exceeded offset benchmarks by approximately 150–300%, depending on hole size, bit type, and drilling mode. These gains were achieved through continuous adjustment of weight on bit (WOB), rotary speed, and hydraulics, based on real-time drilling response. BHA configuration was improved based on the data from every run.

Table 1 - ROP Performance per Section

Hole Size	Avg ROP (ft/hr)	Offset ROP (ft/hr)
17½″	71–103	25–35
12¼″	32 – 78	20–40
8½″	74 (Rotary)	8 – 69 (Sliding)	30–40

In the 17½-inch section, multiple PDC bit deployments achieved average ROP ranging from approximately 80 to over 100 ft/hr, with individual runs exceeding 300 ft of continuous high ROP. These values represent a substantial improvement over offset wells in the same field, where average ROPs in comparable lithologies typically ranged from 25 to 35 ft/hr and were commonly limited by short bit runs and frequent trips.

As shown in Figure 2, drilling performance improvements were primarily driven by increased mechanical and hydraulic loading rather than increased rotational speed. Median on-bottom ROP increased from approximately 2 ft/hr in early runs to 50–75 ft/hr in later runs, while median RPM remained relatively stable at ~60–65 rpm once steady drilling conditions were established. ROP values increased with performance, reaching ~150–190 ft/hr in later runs, reflecting increased variability likely associated with formation heterogeneity rather than drilling instability. In the highest-load runs, further increases in torque and standpipe pressure did not result in proportional gains in median ROP, suggesting an approach toward formation, or hydraulics-limited performance. Overall, the results indicate that drilling efficiency improvements were achieved within a stable operating envelope and were ultimately constrained by subsurface conditions rather than mechanical or operational limitations.

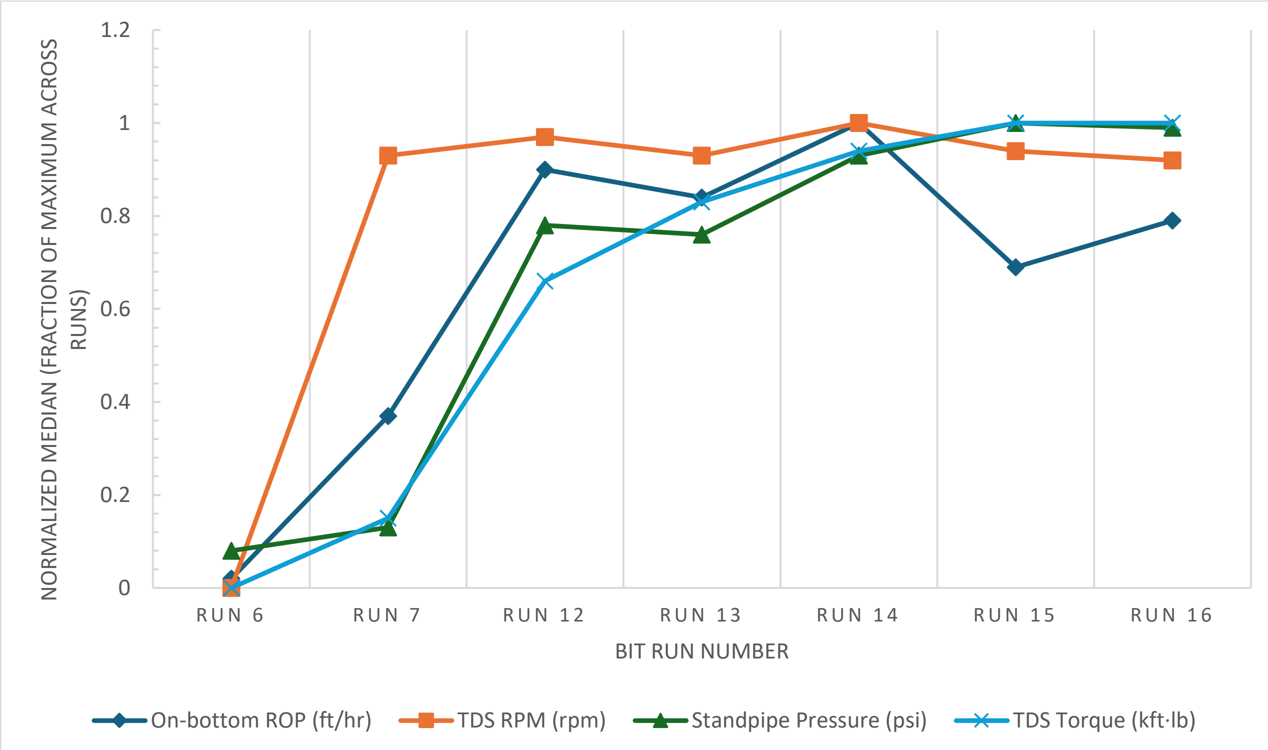

Figure 2 - 17.5″ Hole Drilling Performance Summary. Normalized median drilling parameters by run for the NW55A-29 well

Similarly, the 12¼-inch section exhibited sustained performance improvements, with PDC drilling achieving average ROPs between approximately 30 and 80 ft/hr, compared to 20–40 ft/hr typically observed in offset wells drilled using conventional rotary methods. These improvements were achieved despite operating at reduced weight on bit, indicating effective cutter engagement and favorable drilling dynamics enabled by real-time parameter optimization. Figure 3 shows that median on-bottom ROP increased from approximately 26 ft/hr in Run 17 to ~38–47 ft/hr in Runs 18–20, before decreasing to ~32 ft/hr in Run 21, despite continued increases in applied load. The combination of increasing mechanical and hydraulic loading with a monotonic ROP response indicates diminishing performance returns in the later runs, consistent with an approach toward formation- or hydraulics-limited drilling behavior rather than limitations imposed by surface equipment or operational instability.

The 8½-inch section further confirmed the effectiveness of the real-time optimization strategy. Rotary drilling achieved average ROPs of approximately 70–75 ft/hr, while sliding intervals consistently maintained 28–70 ft/hr, compared to offset well performance generally limited to 30–40 ft/hr. These results were achieved while maintaining directional control and operating within thermal limits, underscoring the robustness of the BHA design and thermal management strategy. The low median ROP observed in Run 24 (Figure 4) is consistent with operational and geological constraints documented in the post-run performance assessment. Although applied weight on bit and torque were comparable to or higher than those in Runs 23 and 25, median ROP was limited to approximately 6 ft/hr, compared with ~76–78 ft/hr in adjacent runs. This behavior is attributed to drilling in highly competent granodiorite and basalt, characterized by elevated coefficients of friction and associated severe lateral vibration. Such vibration reduces effective cutter engagement and drilling efficiency, limiting ROP despite increased mechanical loading. Additionally, portions of Run 24 were drilled in sliding mode at reduced parameters to manage trajectory and temperature, further depressing median ROP. The agreement between reported average and P90 ROP values and those inferred from the normalized-median analysis confirms that the observed low ROP reflects formation- and operations-limited performance rather than insufficient surface capacity or bit inefficiency.

Post-run examination of retrieved bits indicated minimal abrasive wear and no evidence of catastrophic cutter failure. PDC cutters largely maintained structural integrity, with only minor localized micro-chipping observed on a limited number of cutters, consistent with normal wear mechanisms in hard crystalline formations. No widespread cutter delamination or thermally induced damage was observed, confirming that applied drilling parameters remained within acceptable mechanical and thermal limits.

These results demonstrate that real-time drilling optimization, supported by effective thermal management, appropriate bit selection, and continuous performance monitoring, can materially improve drilling efficiency in high-enthalpy geothermal environments. The resulting increases in average ROP, extended bit life, and reduced tripping frequency directly reduce drilling time and operational risk, reinforcing the viability of repeatable EGS development in superhot rock systems.

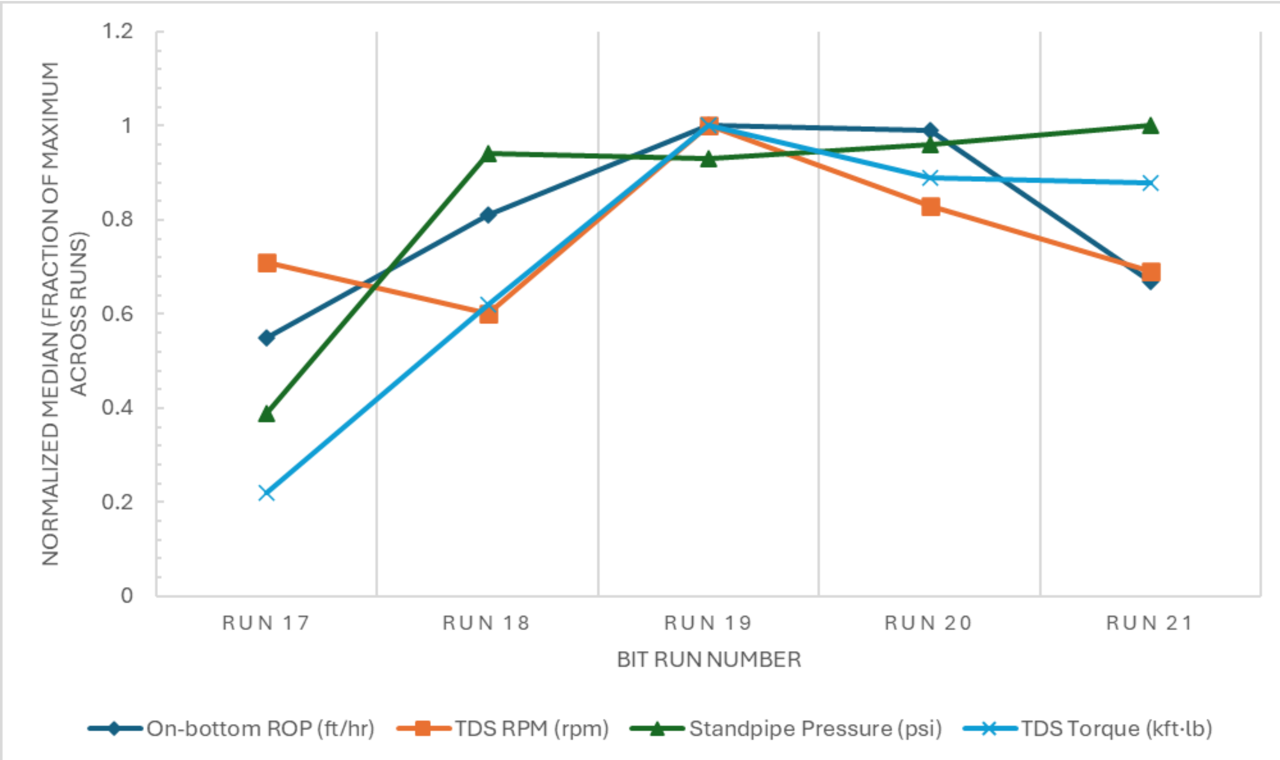

Figure 3 - 12.25″ Hole Drilling Performance Summary. Normalized median drilling parameters by run for NW55A-29 well (runs 17–21)

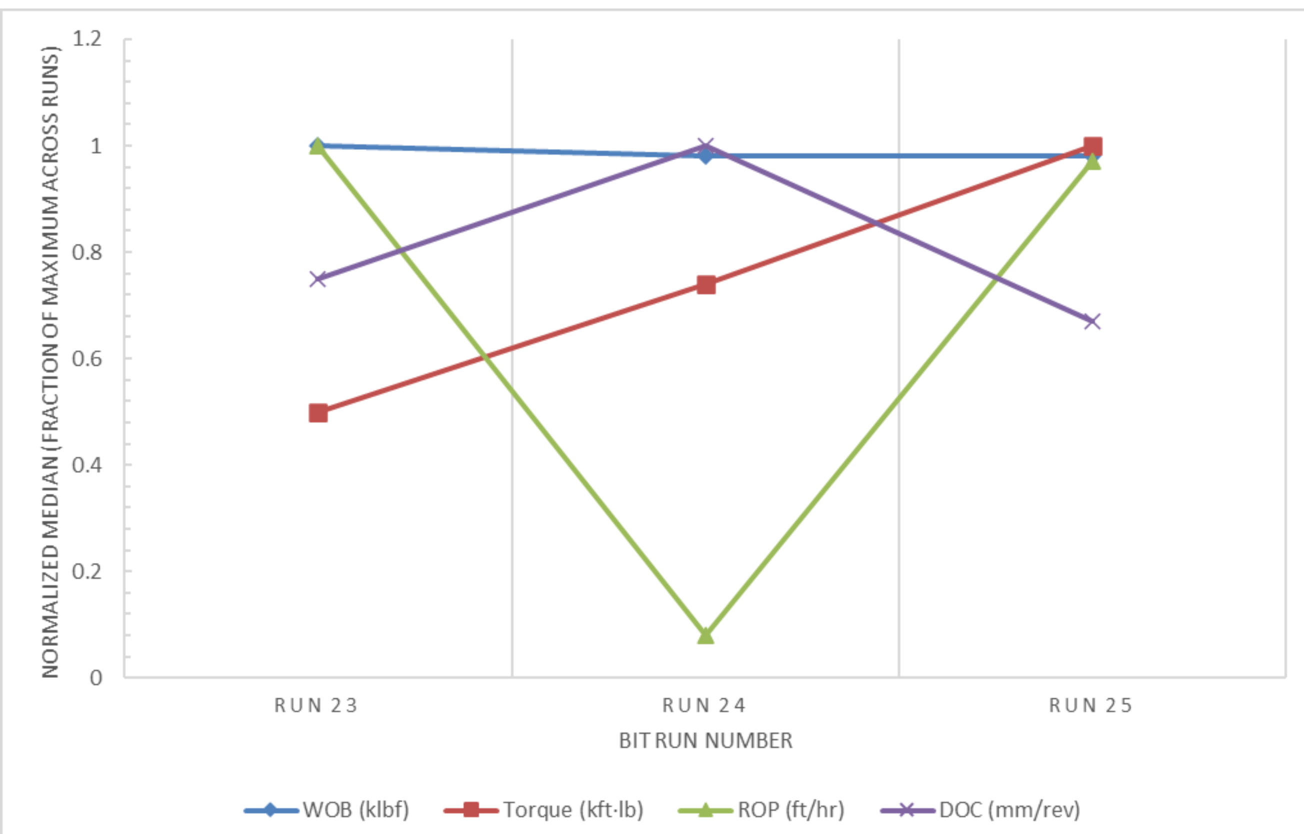

Figure 4 - 8.5″ Hole Drilling Performance Summary. Normalized median drilling parameters by run (Runs 23–25)

6. CORE & COMPLETION INNOVATIONS

A continuous core interval from 9,650 to 9,711 ft recovered at 100% recovery, marking the first successful coring operation in the field above 300°C. The core consisted primarily of dense andesitic tuff and basaltic flows, confirming the fracture network model. A high-temperature sliding sleeve (rated to 2,500 psi and 350°C) was installed at 9,700 ft for selective flow management and successfully function tested at 298°C.

7. ECONOMIC & RISK IMPLICATIONS

The cost structure and risk profile of geothermal drilling at temperatures exceeding 300 °C differ fundamentally from conventional EGS systems, and oil and gas operations. Ultra-hard lithologies, reduced ROP, thermal limitations of downhole tools, and heightened geomechanical uncertainty typically result in large NPT, frequent tripping, and high equipment replacement costs. These factors have historically limited the economic viability of SHR EGS development.

Operational data from NW55A-29 well demonstrate that targeted improvements in drilling system durability and operational execution can materially reduce both NPT and total well cost, even under challenging high-temperature conditions. The detailed NPT record shows that while the well experienced extended periods of lost circulation management, and cement remediation, which are commonly experienced in geothermal applications, the on bottom performance and operational strategies effectively mitigated the impact. Additionally, when compared with prior field campaigns the frequency of NPT events attributable specifically to bit failure, premature tool degradation, and unplanned trips due to tool thermal failures was non-existent. Notably, drilling fluid circulation remained stable during drilling intervals, with no recorded incidents of downhole plugging or thermally induced fluid failure, contributing to improved operational continuity.

Cost data corroborates the observed operational improvements. Comparison of actual well costs against the approved AFE indicates that the well was delivered at approximately 8% below planned cost, despite the technical challenges associated with high-temperature geothermal drilling. When normalized against prior geothermal drilling campaigns in the same field, this performance corresponds to an effective drilling cost reduction on the order of 30%, consistent with internal benchmarking for wells of similar design, depth, and thermal conditions.

From a risk perspective, the data indicate that improvements in ROP and tool survivability have non-linear impacts on total well cost. Preliminary cost modeling based on the observed performance suggests that ROP increases exceedingly approximately 25% can produce exponential reductions in total drilling cost due to cascading effects on rig utilization, reduced exposure to downhole failure modes, and lower cumulative NPT. These effects are particularly pronounced in geothermal wells, where daily rig costs and service integration complexity dominate the economic risk profile.

The documented cost and performance outcomes from NW55A-29 provide empirical support for the feasibility of commercial-scale geothermal development in the >300 °C regime and establish a credible pathway toward future SHR projects targeting reservoir temperatures exceeding 400 °C. Notably, our experience further indicates that drilling does not constitute a fundamental deterrent to accessing >300 °C resources at depths greater than those encountered at Newberry. Thus, these results demonstrate that geothermal drilling at temperatures exceeding 300 °C can be executed with a substantially reduced economic and operational risk profile when drilling system durability, fluid stability, and operational discipline are addressed holistically.

8. LESSONS LEARNED & INDUSTRY RELEVANCE

The repurposing of NW55-29 well and its integration with the newly drilled twin well, NW55A-29, provided a definitive demonstration of twin-well development strategies for superhot EGS. The project conclusively showed that twin-well drilling in reservoirs exceeding 300 °C is both technically viable and operationally efficient, even when one well originates from a legacy configuration with non-ideal geometry and casing history.

A key outcome of the campaign was the confirmation that successful twin-well EGS design does not require identical wellbores, but rather a coordinated system in which legacy constraints and new-well capabilities are deliberately balanced. Although the NW55-29 well exhibited a complex mechanical history, which included tiebacks, cemented annuli, and partially unrecovered liners, pressure integrity was successfully restored through targeted remediation. This enabled its effective use as an injector without full geometric rehabilitation, allowing the new well (NW55A-29) to carry the burden of placement precision and directional accuracy. This division of functional roles proved central to achieving reliable hydraulic connectivity between the wells.

The integration of precise directional control with validated thermal modeling was critical to the success of the twin-well system. Trajectory planning and execution for NW55A-29 explicitly accounted for survey uncertainty, thermal exposure, and tool survivability, enabling accurate placement relative to the injector while maintaining reliable measurement quality throughout drilling. Importantly, this approach resulted in no recorded downhole tool or electronics failures, despite sustained operations in formations exceeding 330 °C. The results underscore the importance of treating thermal exposure as a primary design constraint rather than a secondary operational consideration.

Rather than designing for geothermal equilibrium conditions, both wells were engineered for large thermal gradients, repeated thermal cycling, and high injection pressures. The successful qualification of high-temperature completion components under these conditions validated the design philosophy and established confidence in their applicability to future superhot developments.

Overall, the integrated performance of NW55-29 and NW55A-29 demonstrates that legacy geothermal wells can serve as effective anchors for twin-well EGS systems when pressure integrity is assured and thermal behavior is explicitly incorporated into well design. The project provides a replicable development model that combines strategic reuse of existing wells with precision drilling of new assets, advancing superhot rock development while improving drilling economics and reducing technical risk in extreme geothermal environments.

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