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2025 Geothermal Drilling Cost Curves Update

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ABSTRACT

Drilling activities account for 30% to 57% of the cost to develop and install a geothermal plant. Therefore, an accurate representation of the cost to drill a well is paramount in techno-economic analysis to determine the feasibility of a geothermal power project. In 2022, the National Renewable Energy Laboratory endeavored to revise the U.S. Department of Energy GeoVision baseline drilling cost curves due to extensive improvement in drilling rates at the Utah Frontier Observatory Research in Geothermal Energy (FORGE) demonstration site. That effort did not culminate in the recommendation of new curves, because the actual project costs did not match the reported performance improvements and were at or above the GeoVision baseline. The need for another iteration of this analysis has arisen from industry record drilling performance reported by recent commercial field-scale and demonstration projects, including Fervo Energy's Cape Station, the Utah FORGE 16B(78)-32 demonstration, and Geysers Power Company's GDC-36 demonstration. Therefore, in this work, we have estimated the resulting industry average rate of penetration and bit life and applied these parameters as inputs to the Well Cost Simplified model used in the GeoVision analysis. The revised cost curves show a significant decline compared to the GeoVision baseline. For vertical wells, the magnitude of cost reduction ranges from 12% to 24%, while for horizontal wells, the estimated cost reduction is between 18% and 26%. These revised cost curves align well with actual commercial drilling cost data, and therefore, quantify the economic impact of the utilization of (and advances in) polycrystalline diamond compact bit technology and the application of physics-based methodologies that optimize mechanical specific energy.

1. INTRODUCTION

Drilling to access deep thermal energy in the Earth's subsurface is an important phase in geothermal power plant development. Based on internal analysis carried out by the National Renewable Energy Laboratory (NREL), drilling full-size wells for both resource confirmation and field development currently accounts for 30% to 57% of the overnight capital cost to install a new plant. The variation in the contribution of drilling to the capital cost depends on the resource development option (conventional or next-generation geothermal), which defines the requirements for well design, geometry, and completion. Researchers at Sandia National Laboratories have developed baseline and improved scenarios of drilling costs for the geothermal industry as part of the GeoVision Analysis Supporting Task Force Report: Reservoir Maintenance and Development (Lowry et al. 2017). In the report, they defined two main geothermal well designs: vertical wells with open hole completion and horizontal (i.e., 90° inclination deviated) wells with liner completion (Lowry et al. 2017). These wells can have large-diameter (12.25-in.) or small diameter (8.5-in.) hole sizes.

NREL's effort to update the baseline drilling cost curves in summer 2022 in response to substantial drilling activity at the Utah Frontier Observatory Research in Geothermal Energy (FORGE) project site did not find associated cost decreases to justify lowering the cost curves used in the Geothermal Electricity Technology Evaluation Model (GETEM) (Robins et al. 2022). The justification was not achieved because the actual project costs for the Utah FORGE wells did not match the reported performance improvements and were at or above the GeoVision baseline. Since the 2022 analysis, there has been an uptick in drilling activity in the industry, including projects at Utah FORGE, The Geysers, and Fervo Energy's next-generation geothermal commercial development sites in Nevada and Utah. These projects have recorded remarkable improvements in rates of penetration in hard rock, which have translated into industry-leading drilling rates. Drilling performance improvements have been driven by the increased use of polycrystalline diamond compact (PDC) bits, inter-/intra-project learning (El-Sadi et al. 2024), and technology transfer from the oil and gas industry, including the implementation of the physics-based rate limiter redesign technique (Dupriest and Noynaert 2022, 2024) and multiwell pad drilling (Norbeck et al. 2024).

In this work, we develop revised baseline cost curves for vertical and horizontal geothermal wells of various sizes and completion types by updating the Well Cost Simplified (WCS) model built by Sandia (Lowry et al. 2017) with state-of-the-art drilling performance parameters. This effort will enable accurate representation of the current state-of-the-industry costs in analysis models that use GETEM and NREL's System Advisor Model™ (SAM) as their baseline. Accurate representation of geothermal performance and cost in SAM is vital, because it enables analysis across renewable energy and storage technologies and is integral to resource supply curve and capacity expansion models (Akindipe et al. 2024).

2. RECENT GEOTHERMAL DRILLING PROJECTS

Since 2022, drilling demonstrations and commercial projects have been implemented for both hydrothermal and next-generation resource development. In this paper, we have considered four headline projects with publicly accessible data, including Fervo Energy's Project Red (2023) and Cape Station commercial drilling project (2024), the Utah FORGE 16(B)78-32 production well drilling demonstration (2023), and Geysers Power Company's (GPC's) GDC-36 well drilling demonstration (2023).

2.1 Project Red and Cape Station

Fervo Energy's Project Red was the first operational enhanced geothermal system (EGS) well development in the United States. The project entailed drilling horizontal well doublets (i.e., a production well and an injection well) and a vertical observation well, all adjacent to the Blue Mountain Geothermal Power Plant in northern Nevada. The wells were drilled through a variety of lithologies, including shallow alluvial sedimentary and deep metasedimentary and igneous lithologies. Figure 1 shows the representative lithologies encountered in subsurface, including a phyllitic basement interbedded with quartzite, diorite, and granodiorite (Norbeck et al. 2023; Norbeck and Latimer 2023). The vertical observation well (73-22) was drilled first to a total measured depth (TD) of 8,009 ft (2,441 m). This was followed by the horizontal injection well (34A-22) drilled to 11,220 ft (3,420 m) TD and a horizontal production well (34-22) with a TD of 11,211 ft (3,417 m). Spud to TD durations were 41, 72, and 59 days, respectively. The maximum recorded downhole temperature from the doublet well system was 376°F (191°C) (Norbeck et al. 2023; Norbeck and Latimer 2023). The horizontal doublet is currently connected to the operating Blue Mountain geothermal power plant and has the capability to supply 3.5 MW_e of gross power with a steady output temperature of 347°F (175°C) from Well 34-22 (Norbeck and Latimer 2023).

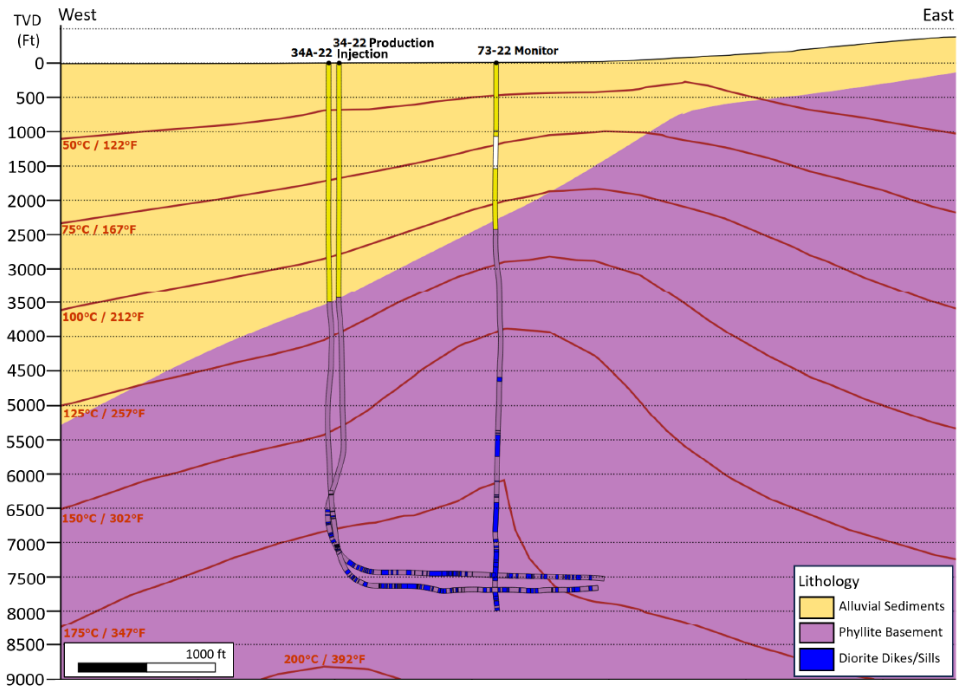


Figure 1: Cross section of the Blue Mountain geothermal resource showing the vertical monitoring well (74-22) and the two horizontal wells (34-22 and 34A-22) (Norbeck and Latimer 2023)

Cape Station is an ongoing EGS-based commercial power project located about a mile west of the Utah FORGE demonstration site in Milford County, Utah. With an earmarked 400 MW_e of power output, the project is anticipated to be the first commercial EGS full-field development. Between June 2023 and September 2024, one vertical observation well and 14 horizontal wells were drilled (Norbeck et al. 2024). The horizontal wells have been drilled from only two pads, Frisco pad and Bearskin pad, proving the applicability of multiwell pad drilling to EGS drilling projects (Figure 2). Cape Station well TD ranged from 13,272 ft (4,045 m) to 15,347 ft (4,678 m), with typical lateral lengths of about 4,700 ft (1,433 m) (Norbeck et al. 2024). The maximum temperature encountered downhole was 444°F (229°C). The producing temperature based on a 30-day cross flow well test using a well triplet (one production and two injection wells, each completed with a 7-in. casing) at the Frisco pad was 382.9°F (195 °C). During the well test, the stimulated production well achieved a peak output of over 12 MW_e and a sustained output of 8–10 MW_e (Norbeck et al. 2024).

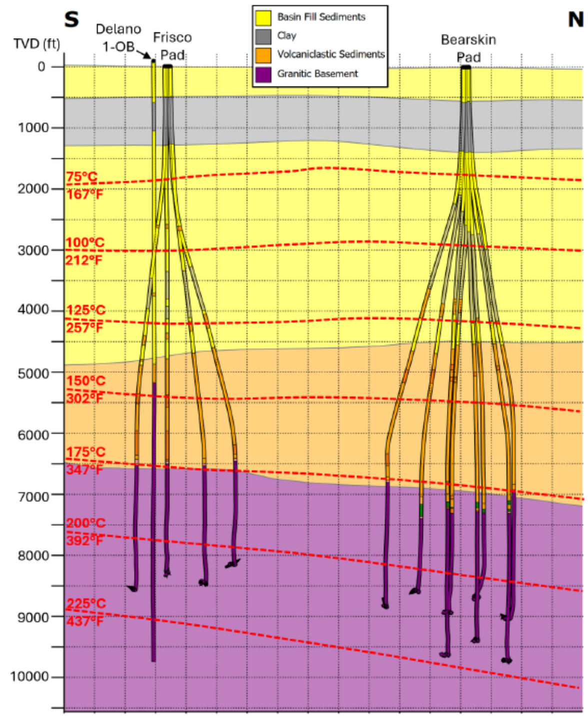


Figure 2: Cross section of the Cape Station resource showing the vertical observation well (Delano 1-OB) and the horizontal wells (Frisco pad) (Norbeck et al. 2024)

El-Sadi et al. (2024) compared the drilling performance and cost across the horizontal wells in Project Red and the first six horizontal wells in Cape Station. Table 1 shows the drilling days and cost per foot for the eight wells analyzed. They recorded significant learning between the two projects, leading to a consolidated 35% interproject learning rate (El-Sadi et al. 2024). From the data in Table 1, the Project Red well costs were close to three times the average cost of the Cape Station wells. Therefore, in the subsequent analysis in Section 3, we only consider the performance and cost data for the Cape Station wells.

Table 1: A summary of performance and cost outcomes from the Project Red well doublet and the first six horizontal wells drilled at Cape Station (El-Sadi et al. 2024)

Project	Well	Days	TD (ft)	Drilling rate (ft/day)	Cost ($/ft)
Project Red	1	71	11,220	158	994.62
Project Red	2	58	11,211	193	1,106.74
Cape Station	3	33.75	13,316	312	633.45
Cape Station	4	25.91	13,272	440	471.59
Cape Station	5	24.26	13,601	504	395.71
Cape Station	6	20.1	13,289	567	346.45
Cape Station	7	23.71	13,949	472	394.08
Cape Station	8	22.27	13,734	539	357.36

2.2 Utah FORGE 16B(78)-32 Demonstration

The Utah FORGE project commenced in 2015 with funding from the U.S. Department of Energy (DOE) Geothermal Technologies Office. Currently, seven wells have been drilled at the site located in Milford County, Utah. This consists of a highly deviated injection and production well doublet, and five vertical observation/seismic monitoring wells (58–32, 68–32, 78–32, 56–32, and 78B-32) (Jones et al. 2024). The injection well, 16A(78)-32, was completed in January 2021, and in June 2023, the production well, 16B(78)-32, was completed in the engineered fracture network created by stimulating the basement rock surrounding the injection well (Jones et al. 2024). 16B(78)-32 was drilled to a TD of 10,947 ft (3,3336 m) with a 65° tangent that kicks off at 5,269 ft (England et al. 2023). The well was spudded on April 26, 2023, and drilling (rig up to rig down and move out) lasted 75 days. The well profile of 16B(78)-32 comprises a 22-in. surface interval (16-in. casing), 14.75-in. intermediate (11.75-in. casing), and a 9.5-in. production interval (7-in. casing down to 10,208 ft) (England et al. 2023). Figure 3 shows the subsurface geological cross section at the site that the wells have intersected. Dominant strata include a sedimentary basin fill strata and successive strata of crystalline basement rocks comprising sheared rhyolite, sheared granitoid, granitoid, and interfingered metamorphic and granitoid (Jones et al. 2024).

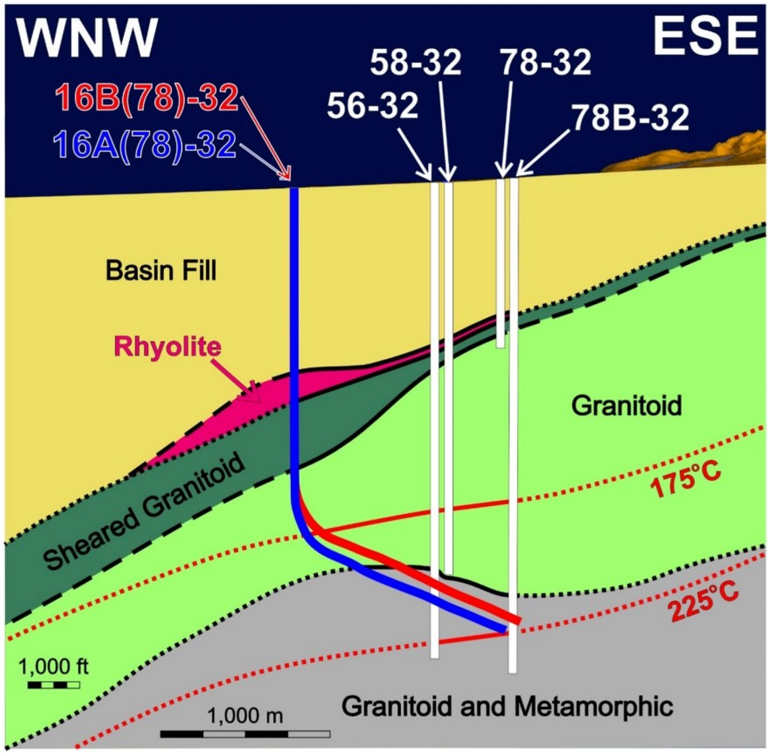


Figure 3: Geologic cross section of the Utah FORGE demonstration project site showing the two deviated wells and four of the five seismic monitoring wells and the lithologies they traverse (Jones et al. 2024)

Significant improvements in drilling rates were recorded relative to previous wells. The average rates of penetration for each bit run (excluding coring runs) are shown in Table 2. The highest average rate of penetration (ROP) recorded was 206 ft/hr for a 29-hour bit on-bottom time.[1] However, this was in an interval with alluvial sedimentary lithology. The fastest hard (high compressive strength) rock drilling average ROP for a single bit run was 173 ft/hr, which was much higher than that recorded for 16A(78)-32 (Robins et al. 2022). Reasons for industry-leading rates of penetration were the utilization of PDC bits with novel cutter designs and the application of physics-based limiter redesign. The limiter redesign technique is a drilling approach that continuously eliminates drilling rate (i.e., weight on bit, rotations per minute, and rate of penetration) limiters by active dysfunction identification and redesign of workflows, bits, and the bottom hole assembly to address or eliminate the dysfunction (Dupriest and Noynaert 2022, 2024). Dysfunctions could include whirl, bit balling, early bit wear, etc.

Table 4: Summary of bit run data for each interval in the Utah FORGE well 16B(78)-32, excluding coring runs (England et al. 2023). The experimental particle impact drilling and hole opener reaming runs were eventually excluded from the drilling performance analysis.

Interval	Depth in (ft)	Depth out (ft)	Depth drilled (ft)	Hole size (in,)	Casing size	Average ROP (ft/hr)	Average on-bottom time (hr)	Bit type
Surface	115	1,146	1,036	22	16	138	7.5	PDC

[1] This is for drilling runs that lasted more than one hour. The actual maximum recorded was 276 ft/hr; however, the bit was pulled out of hole after just 28 minutes.

Intermediate	1,181	4,353	3,172	14.75	11.75	206	15.4	PDC
Intermediate	4,353	4,845	492	14.75	11.75	68	7.2	PDC
Intermediate (particle impact drilling)	4,855	4,910	55	9.5	7	38	1.4	particle bit
Intermediate (particle impact drilling)	4,910	4,978	68	9.5	7	27	2.5	particle bit
Intermediate	4,978	5,269	289	9.5	7	128	2.3	PDC
Curve	5,269	5,957	688	9.5	7	66	10.4	PDC
Curve	5,957	6,545	588	9.5	7	59	10.0	PDC
Curve	6,545	6,610	65	9.5	7	93	0.7	PDC
Curve	6,610	6,951	341	9.5	7	52	6.6	PDC
Tangent	6,951	7,584	633	9.5	7	50	12.7	PDC
Tangent	7,584	8,085	501	9.5	7	67	7.5	PDC
Tangent	8,085	8,585	500	9.5	7	80	6.3	PDC
Tangent	8,585	9,255	670	9.5	7	120	5.6	PDC
Tangent	9,255	9,800	545	9.5	7	109	5.0	PDC
Tangent (hole opener reaming)	9,800	9,863	63	9.5	7	5	12.6	Roller cone
Tangent	9,863	10,250	387	9.5	7	122	3.2	PDC
Tangent	10,304	10,430	126	8.75	Open hole	276	0.46	PDC
Tangent (hole opener reaming)	10,250	10,493	253	9.5	Open hole	160	1.6	Roller cone
Tangent	10,503	10,947	444	9.5	Open hole	173	2.6	PDC

2.3 Geysers Power Company GDC-36 Demonstration

Another DOE-funded geothermal drilling demonstration project is being implemented by GPC, a subsidiary of Calpine Corporation, and supported by experts from Sandia National Laboratories, University of Utah, and Texas A&M University. So far, the project team has drilled a deviated well at The Geysers Geothermal Field as part of the field development that aims to increase the utilization of the hydrothermal resource (So et al. 2024). The well, GDC-36, was drilled to a TD of 9,000 ft (2,743 m) within 69 days, targeting a steam-dominated resource above 475°F (246°C). Drilling was in an area of well-known geology, as there have been offset wells drilled within the area of review at The Geysers, the most prolific geothermal field in the United States. However, as shown in Figure 4, the subsurface was characterized by heterogeneous igneous and metamorphic lithologies, including interbedded fractured layers of graywacke, mélange, hornfels, felsite, and chert, that can limit drilling speeds (Peacock et al. 2020; So et al. 2024). GDC-36 is a deviated (20°– 40° inclination) production well that consists of four main intervals (Table 3): (1) the surface interval: 26-in. hole and 20-in. cemented casing, (2) the first intermediate interval: 17.5-in. hole and 13.375-in. cemented casing, (3) the second intermediate interval: 12.25-in. hole and 9.625-in. casing, and (4) the production interval: 8.5-in. hole and a slotted liner tied back to the surface (So et al. 2024).

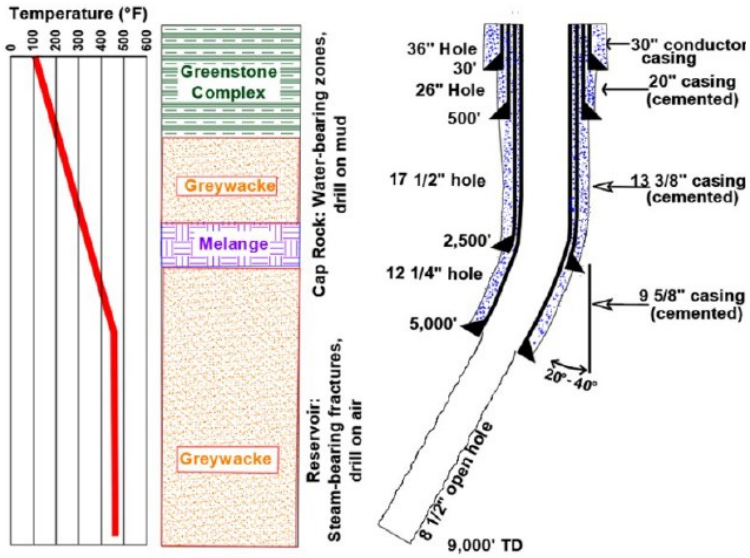


Figure 4: Stratigraphic section and well profile of a typical deviated well in the same area of review as GDC-36 (So et al. 2024)

Table 3: Summary of bit run data for each interval in the GDC-36 well (So et al. 2024)

Interval	Depth drilled (ft)	Hole size (in.)	Casing size	Average ROP (ft/hr)	Average on-bottom time (hr)	Bit type
Surface	400	26	20	-	-	-
Intermediate 1	100	17.5	13.375	28.6	3.5	Roller cone
Intermediate 1	2,014	17.5	13.375	62	32.5	PDC
Curve/Tangent	941	12.25	9.625	99.1	3.2	PDC
Tangent	3,586	8.5	-	21.2	14.1	Roller cone
Tangent	2,212	8.5	-	32.3	6.2	PDC

One of the objectives of the demonstration project was to compare the performance of PDC bits with roller cone bits under similar lithological and petrophysical conditions. Overall, the PDC bits were found to perform better—in terms of average ROP—than the roller cone bits used in the same interval in this demo project and those used in previous offset wells. For example, the average ROP in the first intermediate interval (graywacke and mélange lithology) was 62 ft/hr for a 2,014-ft single PDC bit run compared to 29 ft/hr for a 100-ft single roller cone bit run in the demo project and 12 ft/hr (683-ft bit run) for the offset wells. The improved inter- and intraproject average ROP and bit life were due to the implementation of the same physics-based limiter redesign approach used at Utah FORGE and the utilization of advanced PDC bit designs (So et al. 2024).

3. REVISED BASLINE DRILLING COST CURVES

3.1 Updated Drilling Performance Assumptions

Based on the successes achieved in the projects discussed in Section 2, we have compiled drilling performance data from the three case study projects to update the baseline drilling cost curves that were initially developed by Lowry et al. (2017) for the GeoVison report. Table 4 lists the overall average ROP and bit on-bottom time (equivalent to bit life) for each project. These average values were calculated (for 16B(78)-32 and GDC-36) or compiled (for Cape Station) from public data and project documentation as well as communication with the project developers (El-Sadi et al. 2024; England et al. 2023; So et al. 2024). The values for 16B(78)-32 exclude experimental, coring, and reaming runs, while the values for GDC-36 only include PDC bit runs for better comparison across the three projects. From the data, the average ROP for Fervo's Cape Station wells, Utah FORGE 16B(78)-32, and GPC's GDC-36 were 70 ft/hr, 102 ft/hr, and 65 ft/hr respectively. The considerably higher average ROP for 16B(78)-32 was influenced by the use of several PDC bits that were pulled out fresh and not allowed to undergo considerable frictional wear. Hence, although higher average ROPs were achieved, the average bit on-bottom time was 6.5 hr (the maximum was 15.4 hr). As a result, the project encountered significant bit replacement costs—a total of 16 PDC bits were used. Fervo's Cape Station wells recorded the highest average on-bottom time of 34 hr. However, this was still lower than the 50-hr average bit life assumed by Lowry et al. (2017).

Table 4: Average values of drilling performance parameters—ROP and bit life—for Cape Station wells, 16B(78)-32, and GDC-36. The average values for 16B(78)-32 exclude experimental, coring and reaming runs. The average values for GDC-36 only include PDC bit runs for better comparison across the three projects.

	Cape Station Average	16B(78)-32	GDC-36
Average ROP (ft/hr)	70	102	65
Average bit life (hr)	34	6.5	14

We have used the WCS model developed by Sandia and applied in the GeoVision taskforce analysis (Lowry et al. 2017) to estimate updated costs for geothermal wells. The model takes inputs of well properties, including well geometry (horizontal versus vertical), interval lengths and sizes, and drilling performance parameters, such as ROP and bit life. It calculates both tangible (e.g., cement cost) and intangible (casing time) costs at each well interval. The sum of each interval's costs determines the cost of the well. Table 4 shows the final assumptions implemented in the WCS model. We have assumed 75 ft/hr as the average ROP, as a rounded-up equivalent of the calculated weighted average of 74 ft/hr from the three case study projects. To be consistent with the 2022 analysis, we have kept the bit life at 50 hr. Although the highest average on-bottom time across the projects was 34 hr, each case study project reported that bits were pulled out before significant wear occurred; therefore, achieving longer bit life is not a technical limit but an optimization constraint.

Table 5: Comparison of drilling performance parameters used in the GeoVision baseline analysis (Lowry et al. 2017), the 2022 revised baseline analysis (Robins et al. 2022), and this work (i.e., 2025 revised baseline)

	GeoVision Baseline	2022 Revised Baseline	2025 Revised Baseline
Average ROP (ft/hr)	25	45 (vertical) and 40 (horizontal)	75
Average bit life (h)	50	50	50
Bit cost multiplier	1	1	2
Casing running speed (ft/hr)	300	300	800
Contingency factor	15%	15%	10%

In addition to updating the drilling performance parameters, we have also revised the model to adjust for the cost of PDC bits, since this bit type is evolving as the bit of choice for hard rock drilling, as exemplified in the case study projects discussed in Section 2. The original model assumed that all rotary drilling was implemented with roller cone bits. There is a paucity of public information about the actual costs of PDC bits. However, limited cost data from the Fallon Area drilling project suggest that the average cost of a PDC bit may be twice that of a roller cone bit (Hackett et al. 2020). The degree of cost variation from this average is influenced by the bit size and, more importantly, whether the bit body is repairable or damaged beyond repair after the bit run (Hackett et al. 2020). Therefore, we have assumed a cost multiplier of 2 in the model to account for the increasing use of PDC bits, especially in drilling intermediate and production hole intervals where hard-rock formations are mostly encountered.

Another variable that has been updated is the casing running speed. Casing running speeds have increased in the past decade due to the extensive use of the casing running tool (CRT) technology. CRTs enable the automation of the process of connecting casing joints and running casing with increased efficiency and safety. The default assumption of casing running speed in the WCS model is 300 ft/hr, equivalent to 7.5 joints/hr (assuming a joint is 40 ft long). However, casing running speeds of drilling projects that have utilized CRTs have ranged from 10 to 30 joints/hr (Murray 2005; Warren et al. 2006; Saleh et al. 2018; Guzman et al. 2021). The variation is dependent on casing size (faster for smaller casing sizes) and familiarity of the drilling personnel with the CRT. Therefore, based on the reported data, we have updated this parameter to an average of 20 joints/hr equivalent to 800 ft/hr.

The final variable that has been adjusted away from the GeoVision baseline is the contingency factor. This factor accounts for the cost incurred during trouble time and/or nonproductive time (NPT). Trouble time is incurred during unplanned interventions that focus on correcting issues in the borehole, such as arresting lost circulation and freeing a stuck pipe, whereas NPT generally refers to time spent on unplanned issues associated with the operation of the rig, such as rig repairs, waiting on equipment, etc. (Lowry et al. 2017). Notwithstanding, the two terms are highly interchangeable industrywide. Due to the improvements in drilling efficiency and advances in measurement and logging while drilling (MWD and LWD) that enable real-time data collection and on-site analysis, the industry average trouble time/NPT has decreased substantially. For example, the cumulative cost of Fervo's Cape Station wells was about 84% of the authorization for expenditure, showing the project was not overburdened by unplanned activities (Norbeck et al. 2024). Based on this trend, the original assumption for contingency factor has been reduced from 15% to 10%.

3.2 Revised Cost Curves

Using the input parameters outlined in Table 5 in the WCS model, we have developed new cost curves for geothermal drilling for the well configurations defined by Lowry et al. (2017), including small diameter and large diameter geometries of vertical and horizontal wells. It is important to highlight that unlike the GeoVision analysis and the Cape Station wells with horizontal completions, the other two wells, 16B(78)-32 and GDC-36, although deviated, were not completed with horizontal laterals. 16B(78)-32 was drilled with a 65° tangent (kickoff point = 5,269 ft), and GDC-36 had a tangent between 20° and 40° (kickoff point ~ 2,400 ft). The resulting cost curves are shown in Figure 5 and Figure 6 for vertical and horizontal wells, respectively. We have also plotted the cost versus total measured depth for horizontal wells (small-diameter geometry in Figure 7) to account for variability in lateral lengths (a 1,000-ft lateral at the target depth was assumed in the GeoVision analysis). For each case of well geometry and size, the updated cost curve lies between the GeoVision baseline and Intermediate 1 curves. The downward shift in the curve is largely influenced by faster drilling rates in hard rock formations with the utilization of PDC bits and efficient drilling techniques. Based on the cost data points derived from the WCS model, drilling costs are estimated to have decreased from the GeoVision baseline by 12% to 24% for vertical wells and by 18% to 26% for horizontal wells. These substantial cost decreases justify the need to update the baseline cost curves used in the GETEM and SAM models for near-term Annual Technology Baseline base case scenarios and other geothermal power analysis efforts.

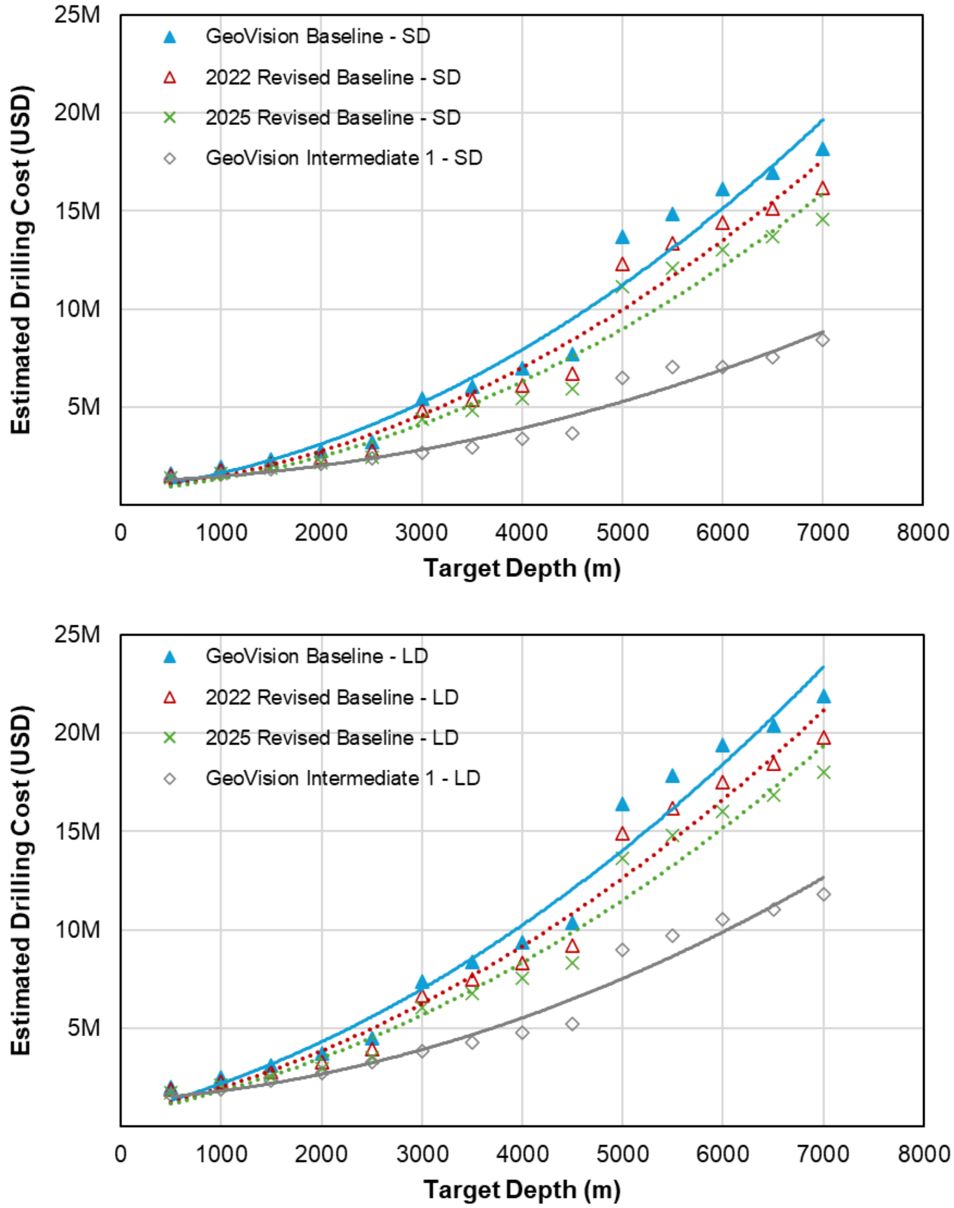
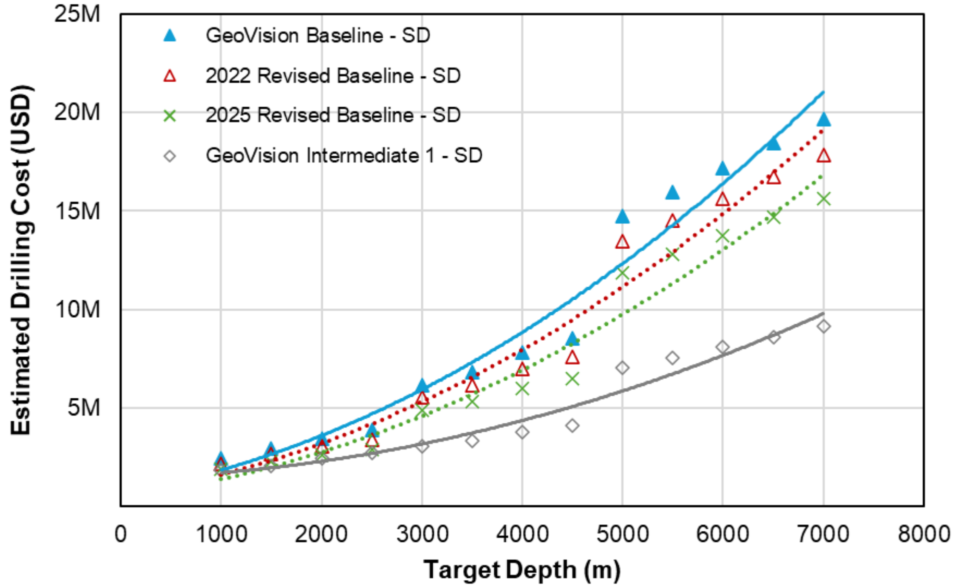


Figure 5: Drilling cost curves for small-diameter, SD (8.5-in.) (top) and large-diameter, LD (12.25-in.) (bottom) open-hole vertical wells showing a downward shift in cost between the GeoVision baseline, the 2022 revised baseline, and the 2025 revised baseline (this analysis). All depths are target depths as defined in Lowry et al. (2017).



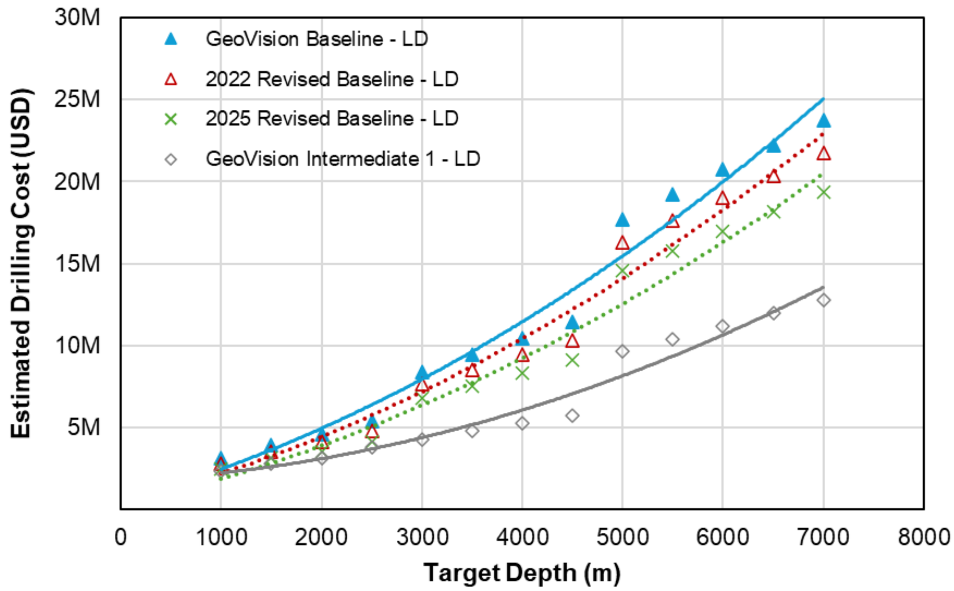


Figure 6: Drilling cost curves for small-diameter, SD (8.5-in. hole and 7-in. slotted liner) (top) and large-diameter, LD (12.25-in. and 9.625-in. slotted liner) (bottom) horizontal wells showing a downward shift in cost between the GeoVision baseline, the 2022 revised baseline, and the 2025 revised baseline (this analysis). All depths are target depths as defined in Lowry et al. (2017). For a horizontal well, the target depth is vertical depth at the resource temperature.

El-Sadi et al. (2024) reported drilling costs for the first six Cape Station wells as costs per footage drilled. Using the well classification from Lowry et al. (2017), the Cape Station wells with 7-in. casing diameter are small-diameter horizontal wells. We have estimated the costs of the six wells based on the reported TDs and represented them in the plots for small-diameter horizontal wells shown in Figure 7. We have also included the Utah FORGE 16A(78)-32 cost for comparison. The graph shows the relationship between TD and cost. This relationship is better suited for horizontal wells, since measured depths and target depths are not the same and can vary depending on the well inclination and lateral length. Figure 7 shows that the 2025 Revised Baseline is within the range of the Cape Station well costs. It is important to mention that the lateral lengths for the Cape Station wells were approximately 4,700 ft, while 1,000-ft laterals were assumed for the GeoVision (and this analysis) in the WCS model; hence, these comparisons should be treated as approximates. Notwithstanding, the revised cost curves generally align with the commercial project cost data and can be used as estimates to quantify the economic impact of the utilization of PDC bit technology and the application of physics-based methodologies that optimize mechanical specific energy.

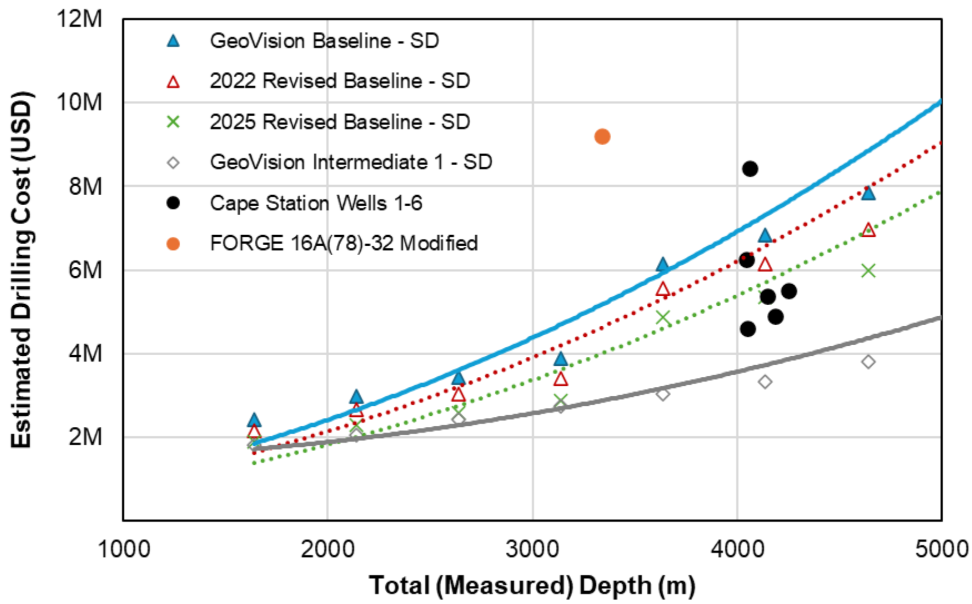


Figure 7: Comparison of new baseline costs with actual drilling cost data from Cape Station and FORGE. The 2025 Revised Baseline generally aligns with commercial development cost trends.

4. CONCLUSION

We have developed revised baseline drilling cost curves for the U.S. geothermal power industry. The rationale for updating the 2017 GeoVision baseline stems from the need to represent ongoing enhancements in drilling performance across various projects and geological settings. Four recent projects served as case studies for this update, including Fervo Energy's Cape Station, Project Red, the Utah FORGE 16B(78)-32 demonstration, and Geysers Power Company's GDC-36 demonstration. This analysis revises the "2022 GETEM Geothermal Drilling Cost Curve Update" using state-of-the-art drilling performance assumptions. These parameters, including ROP and bit life, have been derived from Cape Station, 16B(78)-32, and the GDC-36 public data. By incorporating the resulting average ROP and other updated assumptions regarding PDC bit cost, casing operation, and contingency into the WCS model, the resulting cost curves represent a notable shift toward the GeoVision Intermediate 1 technology scenario. Specifically, for vertical wells, cost reductions of 12% to 24% beyond the GeoVision baseline have been achieved, while for horizontal (or deviated) wells, the reduction ranges from 18% to 26%. This analysis justifies the need to update the baseline drilling cost curves in the GETEM, SAM, and other geothermal power analysis models. Incorporating the revised curves will improve the accuracy of geothermal cost estimation in these models and corresponding derivative analyses, such as resource supply curves evaluation, capacity expansion modeling, and workforce development assessment.

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