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Drill Bit Considerations for Hard Rock Drilling in Newberry, Oregon

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1 ABSTRACT

Drilling through hard igneous formations commonly encountered in geothermal wells demands tools and parameters specifically engineered for these conditions. Generic designs optimised for sedimentary or metamorphic rocks typically result in poor drilling efficiency and reduced bit life. This paper presents the design and field performance of a 12.25” polycrystalline diamond compact (PDC) bit optimised for drilling hot, hard and abrasive volcanic tuff, andesite, and rhyolite in the vicinity of Newberry, Oregon. This bit design was also required to maintain strict directional control. The design methodology clearly differentiates between the roles of the primary cutting structure and the trailing support elements to enhance durability in the vibration-rich environment characteristic of igneous drilling. Field results are presented from a run in which the bit drilled 1,952 ft of volcanic rock at an average rate of penetration (ROP) of 46 ft/hr before being pulled in a repairable condition for a BHA change. Post-run analysis validates the design assumptions and identifies opportunities for further optimisation. The paper concludes with key insights and recommends best practices for PDC bit design and selection in geothermal drilling applications.

2 INTRODUCTION

2.1 The challenge

The Newberry project is located on the northwestern flank of Newberry Volcano, approximately 37 km south of Bend, Deschutes County, central Oregon. The project area lies on federally managed land administered by the U.S. Bureau of Land Management (BLM), with surface oversight by the U.S. Forest Service, immediately adjacent to the Newberry National Volcanic Monument. Within this geographic and regulatory setting, the project was designed to test the viability of next-generation geothermal development.

The main objective of the project was to create a Enhanced Geothermal System (EGS) at temperatures greater than 300degC. To achieve this, a legacy well (55-29) was repurposed as the injector and restimulated, and a new well was drilled (55A-29) to become to producer. Achieving these objectives required drilling and completion designs tailored to the geologic conditions encountered on the west flank of Newberry Volcano.

The formations encountered on the west flank of Newberry Volcano above 4,000 ft are dominated by volcanic-derived and range from lava flows to tuffs, air-fall ash to fragments up to 2 to 3 cm, and breccia. The lower portion of the well, below, is dominated by subvolcanic microcrystalline roc and are brittle hard rock. Table 1 shows the identified lithology column for the Newberry drilling project. This bit was designed to start drilling at 4,200ft in the Basaltic Andesite. These lithologic variations with depth directly influenced drilling, trajectory, and bottomhole assembly (BHA) design decisions.

Table 1: Lithology column for the Newberry project

Depth [ft]	Lithology	Density [g·cm-3]
0-2000	Debris Flow - Tuffs	2.27
2000-4000	Basalt - Debris Flow	2.27
4000-6000	Basaltic Andesite	2.53
6000-7000	Welded Tuffs	2.58
7000-8000	Tuffs	2.58
8000-8750	Basaltic Andesite	2.58

8750-9600	Granodiorite	2.64
9600-10000	Basalt	2.64
> 10000	Granodiorite	2.68

In parallel with these geologic considerations, well trajectory planning of the producer well was governed by stimulation design requirements,, which in turn was based on the required inter-well spacing, stimulation volume, and acceptable pressure drop. Lateral separation between the two wellbores, that defined the trajectory design, was derived directly from stimulation design constraints. This specified the azimuth, inclination to stay parallel to the existing injector, and the distance between the wellbores. The stimulation program was designed to recognise which depthshave critical spacing requirements. 55A-29 was drilled using a positive displacement motor (PDM), with trajectory control achieved through sliding and rotating. The well was drilled vertically to 4,331 ft TVD, then kicked off toward the northwest. Placement prioritised minimising survey error while maintaining the required parallel length and toe spacing relative to the existing producer. The error of ellipses defined the surveying strategy. To deliver the trajectory, the BHA design revolved around the PDM and PDC strategy. With Newberry being a hard rock drilling application with high weight on bits meant that stabilisation was key for the BHA chosen based on the traditional three points of contact. This approach was customized and developed in collaboration between Mazama, ZerdaLab, and the stabiliser vendor.

Table 2 shows the bit run performances from the two offset wells. The offset wells were from about one decade ago so the expectations were to beat all of the offset runs. Especially in the 12.25in. and 8.5in. The concern were the short run lengths and high bit gradings upon pulling. The focus became on getting the bit designs aggressive and stable enough to extend longevity and reduce downhole drilling dysfunction.

Table 2: Offset bit runs

Well	Size [in]	TFA [in²]	In [ft]	Out [ft]	Footage [ft]	Hours	ROP [ft/hr]		In	Out	Major	Loc	Brg	Gauge	Other	Pull
Offset 1	17.500	1.485	1,255	2,658	1,404	95.0	14.8		3	6	CT	G	E	1	WT	TQ
Offset 1	17.500	1.325	2,658	4,396	1,739	113.0	15.4		3	4	WT	A	E	1	NO	DTF
Offset 1	17.500	1.767	4,396	4,761	364	36.0	10.1		2	2	WT	A	E	1	NO	TD
Offset 1	17.500	1.325	4,761	4,761	0	7.0	0.0		2	3	WT	A	E	1	NO	TW
Offset 1	17.500	1.325	4,761	4,761	0	45.0	0.0		3	4	WT	A	E	1	NO	TD
Offset 1	12.250	1.325	4,761	5,927	1,165	79.0	14.8		4	8	WT	A	E	0.125	NO	HR
Offset 1	12.250	1.804	5,927	6,890	965	70.5	13.6		4	3	CT	G	F	1	WT	TW
Offset 1	10.625	1.804	6,888	7,414	525	40.0	13.2		3	7	BT	G	E	8	WT	TQ
Offset 1	10.625	1.804	7,414	8,542	1,129	61.0	18.5		5	7	CT	A	E	2	WT	HR
Offset 1	10.625	1.804	8,542	9,173	630	45.0	14.0		4	4	WT	A	E	1	NO	DTF
Offset 1	10.625	1.804	9,173	10,347	1,175	48.0	24.5		6	8	BT	A	E	0.75	WT	PR
Offset 1	10.625	1.804	10,347	10,762	413	48.0	8.7		4	4	WT	A	E	0	NO	DMF
Offset 1	10.625	2.071	10,762	11,599	837	36.5	22.9		6	8	WT	A	3	1	BT	PR
Offset 2	17.500	1.767	140	284	144	11.3	12.9		3	3	NO	A	6	1	NO	BHA
Offset 2	17.500	1.767	294	1,122	827	56.8	14.6		1	1	NO	A	0	1	NO	HP
Offset 2	17.500	1.325	1,122	2,723	1,601	76.0	21.1		3	3	NO	A	5	2	NO	TD
Offset 2	17.500	1.325	2,723	3,124	400	23.5	17.0		7	4	BT	A		0.25	WT	PR
Offset 2	17.500	1.325	3,124	3,723	600	47.5	12.6		1	2	WT	A	E	1	NO	WO
Offset 2	17.500	1.804	3,723	4,265	541	62.0	8.7		7	8	BT	A	F	0	WT	PR
Offset 2	17.500	1.114	4,265	4,409	144	13.5	10.7		8	8	BT	A	F	3	WT	PR
Offset 2	12.250	1.325	4,409	4,966	558	44.5	12.5		2	3	CT	G	E	3	WT	BHA
Offset 2	12.250	1.325	5,663	6,465	801	66.0	12.1		1	1	NO	A			NO	BHA
Offset 2	8.500	1.804	6,465	7,236	771	69.6	11.1		6	8	WT	A	F	12	NO	TQ
Offset 2	8.500	1.804	7,236	8,331	1,096	58.0	18.9		6	8	BT	A	F	12	LT	HR
Offset 2	8.500	1.804	8,331	9,234	902	46.0	19.6		6	8	BT	A	F	12	BF	TQ

Offset 2	8.500	1.804	9,234	9,736	502	67.0	7.5		4	6	CT	A	E	2	NO	HR
Offset 2	8.500	1.325	9,736	10,060	325	44.0	7.3		6	6	WT	A	E	2	NO	TD

2.2 Preface

The bit subject of this paper, DB616, was specifically engineered to address the combined challenges of hard, abrasive, and highly interbedded igneous formations encountered in the Newberry field. The design objectives were derived by offset well performance, anticipated drilling dysfunctions, and the need for sustained directional control and high temperature conditions.

This bit was run by experienced rig crews using a well-engineer BHA and associated drilling technology. The present paper focuses specifically on bit performance, while broader aspects of the drilling execution, stimulation strategy, and integrated well delivery for the Newberry project are documented in companion publications (e.g., Gonzalez Luis et al.,2026; and Grubac et al., 2026). This allows the paper to focus on bit design and performance results applicable to other hard-rock geothermal wells.

2.3 Evolution of bit design for volcanic drilling

Over the past decade, polycrystalline diamond compact (PDC) bits have emerged as a transformative technology for igneous rock drilling, substantially outperforming conventional roller cone and diamond-impregnated bits in hard rock applications. This is driven by significant advancements in PDC cutter materials, cutter-rock geometric optimisation, cutter-rock force modelling and better understanding of bit design. These advancements have been validated through multiple geothermal field applications worldwide.

By way of example, field data from the Chocolate Mountains geothermal project (2011-2012) demonstrated that PDC bits achieved rates of penetration (ROP) of 26.5 feet per hour (ft/hr) in granite formations, compared to just 10.7 ft/hr for comparable roller cone insert bits, representing a 148% improvement, while reducing drilling costs by 27%. (Raymond et al., 2012)

Subsequent studies in other geothermal provinces have reinforced these early performance gains. A 2016 comparison between roller cone and PDC bits drilling igneous rock in Kenya's rift valley showed that PDC bits drilled 84% faster and 213% further than roller cone bits. (Letvin et al., 2016)

Beyond regional performance, bit diameter has also been shown to play a significant role in the magnitude of performance improvement. A 2020 paper from New Zealand demonstrated an improved performance of PDC bits compared to roller cone bits was greater in smaller sizes; the 20.75" PDC bit reduced cost by foot by around 25% while the 12.25" bit reduced cost by 70%. Similarly performance gains in 20.75" were around 30% while the 12.25" increased performance by up to 50%. These bits drilled through a range of interbedded rock types including hard rhyolite (Lock et al., 2020). The Tauhara geothermal field in New Zealand has many similar characteristics with around 3,300 ft (1,000 m) of drilling the 12.25" section including igneous lithologies such as ignimbrite, andesite and rhyolite with using aerated mud on a bent motor BHA. Many wells have been drilled in this area with a multitude of papers released for additional information about drilling similar formations, and similar trends have also been observed in long-term field optimisation studies.

Further work in the Geysers Geothermal Field has demonstrated the performance of PDC bits in igneous rocks against roller cone bits and optimisation within the PDC category available over sequential wells. A performance increase over 5 wells is recorded with a 500% instantaneous ROP improvement and 200% longer bit life. Considering performance over roller cone bits, the PDC bits are reported to improve performance by 400% for 17.5", 700% in 12.25" and 50-70% for the 8.5" section. (So et al., 2024). Coupled with the data from New Zealand referenced above, this points towards 12.25" as the sweet spot for performance improvements for fixed cutter bits over roller cones.

In geothermal drilling specifically, recent market analysis indicates that fixed cutter PDC bits account for 45% of the geothermal drill-bit market in 2025 (Coherent Market Insights, 2025) with a greater market share than roller cone bits. This has lagged the PDC dominance in oil and gas drilling partly due to the more challenging drilling but also due to greater risk aversion from investors.

3 DRILLING DYNAMICS CHALLENGES

Drilling hard and abrasive formations typically demands the application of substantial axial force to the bit, which in turn requires a heavy, stiff, and mechanically robust BHA. Hard crystalline rocks such as basalts, granites, and metamorphic units exhibit very high compressive strength and low drillability, meaning that insufficient weight on bit (WOB) results in inefficient cutting, and elevated vibration. To deliver the required WOB at the bit, operators often deploy long sections of drill collars to increase stiffness and weight. In near vertical intervals, these collar sections may extend for tens of meters, sometimes approaching or exceeding 100 m, without intermediate stabilisation. Such long, unstabilised sections create a BHA with a large unsupported length, making it more susceptible to bending modes, lateral displacement, and dynamic instability.

This susceptibility is amplified in geothermal environments, where the friction factor between the BHA and the borehole wall is typically much higher than in conventional oil and gas wells. Aerated drilling fluids provide minimal lubrication and do not form a mud cake. Without a filter cake, the BHA remains in direct contact with abrasive rock surfaces, increasing frictional forces and promoting stick-slip, abrasive wear, and lateral vibrations. The combination of eccentric mass distribution in the collars, high friction, and poor damping from low viscosity fluids creates ideal conditions for the onset of BHA whirl. Once initiated, whirl can rapidly be amplified by friction forces (transition from forward to backward whirl), causing severe lateral vibration, accelerated damage to BHA components and the bit.

Lithology transitions introduce another layer of complexity. When drilling from a hard formation into a softer one, the depth of cut increases dramatically. If WOB is not reduced promptly, the bit may cut too deeply, causing an unintended increase in dogleg severity. This effect is particularly pronounced in assemblies with bent motors or PDC bits with high side cutting index. The resulting wellbore tortuosity introduces additional frictional drag, increases torque fluctuations, and creates localized pinch points where the BHA weight becomes partially suspended. These zones of hanging weight can lead to erratic WOB transfer, further damaging cutting structure of the PDC bit.

Wellbore spiralling is a well studied phenomenon in directional drilling mechanics. Pastusek et al. (2003) demonstrated that spiralling is fundamentally driven by oscillatory behaviour of the BHA, particularly when side loading at the bit is present. This side loading can arise from aggressive bent housing settings, high side cutting forces, or asymmetric cutter engagement. Spiralling is not directly dependent on ROP; rather, it is a geometric response to the oscillatory lateral forces acting on the bit. Interestingly, the oscillations that generate spiralling often diminish at higher ROPs because increased penetration stabilises the bit-rock interaction and reduces the amplitude of lateral motion. However, at lower ROPs or in stiff formations, these oscillations can persist, producing a corkscrew shaped wellbore that complicates subsequent drilling and completion operations.

High WOB also increases the side forces acting on stabilisers, which can become a significant source of torsional dynamics. As stabilisers experience higher lateral loading, they generate frictional torque spikes that interact with the bit's cutting structure. Stick-slip, commonly observed in deeper sections, is often interpreted as a torque response to the bit's inability to maintain a consistent depth of cut. When the bit momentarily stalls due to high friction or insufficient RPM, torque builds up in the drillstring until it releases suddenly, causing rapid acceleration. Counterintuitively, replacing the bit with a less aggressive design does not always mitigate this behaviour. A less aggressive bit may reduce instantaneous torque, but it also reduces cutting efficiency, which can increase the tendency for stick-slip by forcing the bit to operate at lower DOC and higher frictional contact at the BHA.

Bit chatter is another dysfunction frequently encountered in hard rock drilling. It occurs when the PDC cutting structure becomes ineffective at maintaining a stable cutting action. This can happen when the bit is operating at very low depth of cut in extremely hard formations, causing cutters to intermittently engage and disengage the rock surface. It can also occur when cutters develop wear flats, which increase friction and reduce cutting efficiency. The intermittent cutting action associated with chatter acts as a powerful excitation mechanism for high frequency torsional oscillations (HFTO). HFTO is characterized by rapid, small amplitude torsional vibrations that can cause severe damage to BHA components. The situation can be unintentionally worsened by the use of shock subs. While shock subs are effective at reducing axial vibration and bit bounce with roller cone bits, they can alter the stiffness distribution of the BHA in a way that increases susceptibility to torsional resonance. This coupling effect has been documented in the literature, including the work of Warren et al. (1998) and Zamudio et al. (1987), who showed that shock sub use with drag bits can inadvertently amplify torsional oscillations under specific operating conditions.

4 PDC TECHNOLOGY DEVELOPMENT

4.1 PDC development

PDC cutter development has been instrumental in the improved penetration of PDC bits in the igneous drilling market. Over the last 20 years since the first cutters were leached, the sintering manufacturing process for cutters has improved in pressure (approximately from 5GPa to 9GPa) and temperature (1,800°K to 2,200°K). The cobalt leach depth in the diamond (which creates a much more durable zone) in that time has improved from around 200µm on the face only to over 1400µm on face and sides. The thickness of available diamond tables has increased from under 2mm to over 4mm.

Manufacturing methods over this timeline have improved the diamond shaping from a simple chamfer choice to complex non-planar geometries. These have been shown to be both more efficient (Rahmani 2019) and more durable (Rahmani et al. 2020) than traditional planar cylindrical cutters.

The result of these advances is that an application that was not PDC viable 20 (or in some cases as few as 5) years ago is now optimally drilled with a PDC bit.

With enhanced technology, costs of cutters has also increased. A common approach is to 'blend' cutters putting more expensive, high performance cutters in locations of greatest risk of damage (eg. shoulder) and cheaper, lower performance cutters in locations less prone to damage (eg. cone). In predictable applications this approach can be a good strategy; reducing cost for minimal risk increase. In interbedded igneous lithologies where drilling is less predictable, this approach can be risky. Drilling in the Geysers geothermal field for example revealed that identical bits had radically different performances; of 11 bits, 2 were identical 8.5" bits which achieved both the highest footage and also the worst. The lower performing bit failed due to a ringout in the cone, and although this was not explicitly mentioned, this is a region where lower cost cutters are often blended. (Su et al. 2025)

4.2 Support components

Support components are those which are not directly responsible for drilling, but provide support to the primary cutters. This support is generally to mitigate drilling dysfunction (eg. torsional/ lateral vibration, primary cutter overload). The range of options for these components has expanded significantly over time. Where once the option was either putting additional cutters buried in the blade or carbide domes, there are now many more options such as conical or wedge shaped PDC elements. These wedge and conical elements generally have an impact to failure load around 300% greater than for a cutter.

Incorrect choice of components can cause or worsen dysfunction. For example, it has been shown that burying 'secondary cutters' in the blade tracking behind the primary cutting structure can cause HFTO while use of impreg like material reduces the HFTO (Tipples et al 2021). Aside from HFTO, use of these secondary cutters can cause micro-balling and reduce efficiency while offering lower protection from impact than conical or wedge shapes.

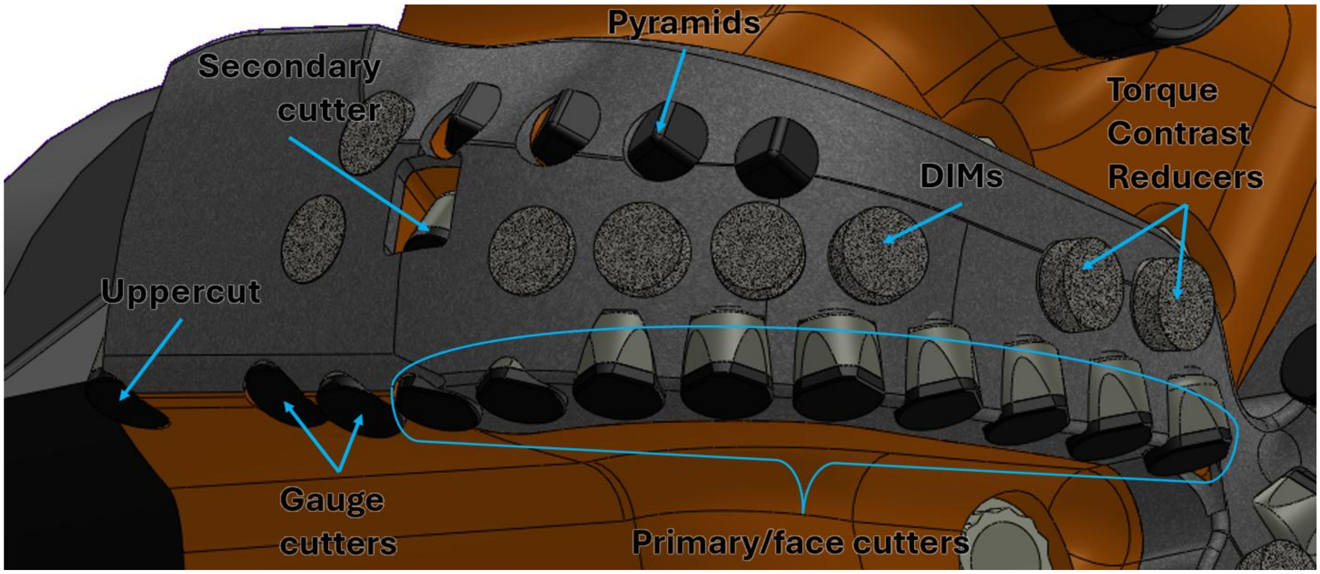

Figure 1 - Anatomy of a bit including various named parts from this paper such as diamond impregnated material (DIM)

4.3 Cutter force modelling methodology

PDC rock cutting force modelling represents a fundamental approach to understanding and predicting the complex mechanical interactions between cutting elements and rock formation during drilling operations. The models used enable the quantitative prediction of normal and tangential forces acting on individual cutters as functions of position and orientation on the bit, drilling parameters, and rock properties. The primary modelling approaches include the classical linear cutting theory, which treats rock removal as a process governed by shear and tensile failure modes, augmented by friction mechanics and rock material failure theories. By integrating these force models with bit-scale geometric considerations, designers can systematically optimise critical parameters such as cutter size, orientation, placement, and exposure to achieve desired performance outcomes including enhanced rate of penetration, improved weight-on-bit efficiency, reduced drilling-induced vibrations, and extended bit life. Furthermore, force modelling facilitates the evaluation of cutter loading distributions across the bit face, enabling identification of potential stress concentrations that may lead to premature cutter damage through chipping, delamination, or thermal degradation, thereby informing material selection and thermal management strategies in next-generation PDC bit designs.

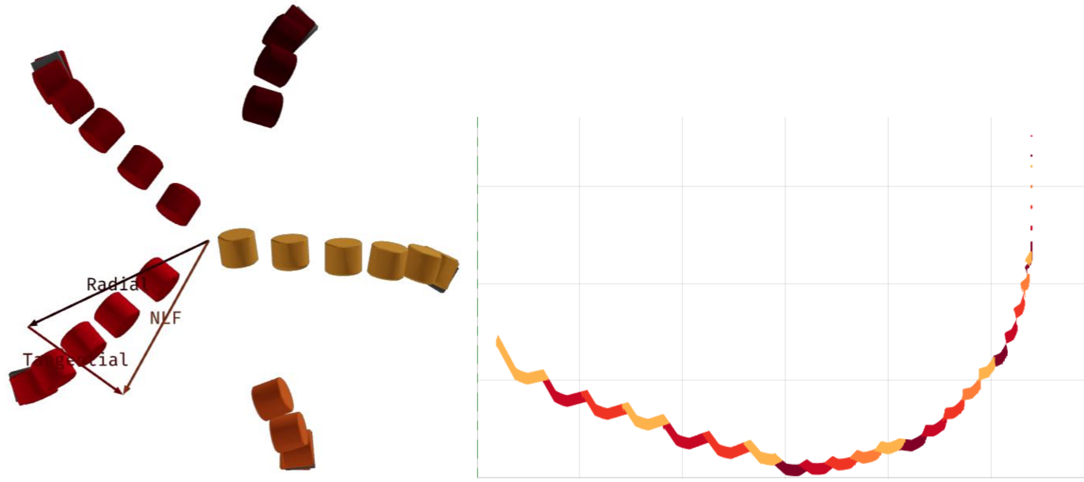

Figure 2 - An example of force modelling on a bit to keep imbalance (net lateral force) low and cutshape modelling

4.4 PDC bit design development

It is well known that bits with fewer cutters and a more aggressive design have a higher ROP. There is a common thought that the number of cutters dictates durability. This is not always true; for the same energy input (WOB, torque) a bit with more cutters will drill more slowly with a lower efficiency, where the lost efficiency is translated into drilling dysfunction such as vibration and heat. Additionally, a less efficient bit usually has cutters that travel a greater linear distance giving greater risk of abrasion. If the cutters can 'bite' into the formation beyond a critical depth of cut, the rock failure mode changes from ductile to brittle which is far more efficient. Notably, for igneous drilling the greater the strength of the rock, the smaller this critical depth of cut is (Zhou et al. 2013).

As cutter technology and bit design has improved, the number of cutters required on a bit has decreased. As the cutter count decreases, the depth of cut increases which takes advantage of the lower critical depth of cut in hard formations. It is for these reasons that a bit with more cutters which may appear more durable at first appearance is actually not capable of drilling as far.

With the reduced cutter count in an efficient bit, support components should be chosen to provide support for the primary cutting structure. Specifically, ensuring that they can carry excess load in vibration events which would otherwise overload the primary cutters.

5 DESIGN METHODOLOGY & DECISION FUNNEL

5.1 Bit type

PDC bits are demonstrated to have higher ROP and longer life than roller cone bits. The higher ROP is due to the rock failure method; crushing with roller cone bits is less efficient than shearing with PDC. The longer life comes from lack of moving parts; a PDC bit can generally be run until the cutters wear out. They also have a higher theoretical temperature limit due to potential for seal removal. Finally, PDC bits are often repairable. Roller cone bits often have a lower upfront cost, but because of lower ROP and duration, cost per foot is generally higher than for a PDC bit.

Hybrid drill bits should also be briefly mentioned. These bits combine fixed cutter PDC and roller cone into a single product. In igneous rocks these bits have a significant strength in addition to several weaknesses. The major strength is that these bits, much like roller cone bits, are highly resistant to torsional vibration which can be critical in interbedded formations. Unfortunately, in addition to lesser problems like bearing life the bigger problem is the flat profile of the bit. The flat profile can result in significant wear issues on the very short shoulder where formation dip angles cause a small number of cutters to take excess load when transitioning from soft to hard formations. The luck of the dip angle is one of the reasons why hybrid bits sometimes performs very well in hard interbedded rocks and on other times the performance is far worse than fixed cutter bits. Additionally, the performance of hybrid bits in hard rock is between a roller cone and PDC; Savage et al. (2023) compares a very heavy set PDC bit (816 with long shoulder and secondary cutters) to 2 hybrid bits. At 45klb, the PDC bit achieves 3x ROP and requires 3x torque of the hybrid bits with a similar MSE. Notably, the torsional fluctuation of the PDC bit is significantly smoother when the cutters are able to 'bite' the formation (associated with the critical depth of cut previously discussed). Using a lighter set bit should achieve this critical 'bite' at much lower WOB with less dysfunction energy (assuming that a similar percentage of energy put into the system is lost to dysfunction based on the same MSE between hybrid and PDC bits).

As discussed in prior pages, PDC bits are well proven in similar igneous rock types. Based on offsets from New Zealand and USA the 12.25” bits have the best comparative performance so this application is the ideal application for PDC bits.

5.2 Primary cutting structure layout

The design strategy for this bit was to maximise efficiency while ensuring that durability is sufficient to get through the highly interbedded and hard igneous rock section.

A 6 blade layout was chosen to allow space for significant additional support components. Placing a 7th blade would theoretically allow a greater number of PDC cutters (thus greater abrasion resistance and greater redundancy) but the reduction in support component count in the nose and shoulder would more negatively affect overall performance.

The tip profile of the bit is composed of a novel 4 curve profile to allow a flat nose, the deepest cone allowable on a motor and a longer shoulder than normal. The flatter nose helps the cutters in this region better load balance in the highly heterogeneous formations. The deeper nose is useful for stabilisation and the longer shoulder allows a small number of extra cutters in the shoulder region to compensate for the 6 bladed limit.

Cutter spacing and backrake distribution was balanced to allow higher efficiency in the centre of the bit and a focus on durability on the shoulder. All cutters had a full length substrate to avoid weak points. Cutter shape selection used a well proven scribe shape which improves efficiency without decrease in durability compared to traditional planar cutters. The grade of cutter chosen was balanced considering the highly heterogeneous formation coupled with abrasive rhyolites. Every PDC cutter on the bit used this same high grade with no blending.

Two rows of gauge cutters are used on this bit to give increased redundancy and ability to hold gauge. The first row of gauge cutters were placed to cut rock while the second row, at a more passive backrake angle, are placed to ensure the bit stays in gauge in the event of failure of the first gauge cutter without the risk of excess lateral cutting ability. For further redundancy, a row of secondary near-gauge cutters were placed behind the last face cutter on each blade to maintain hole diameter in the event of multiple catastrophic failures. This location avoids many of the pitfalls of secondary cutters and so was not considered a risk.

Finally, the primary cutting structure is balanced using force modelling software to ensure that it runs smoothly in use.

5.3 Supporting the primary cutting structure

With the primary cutting structure established, support components were then chosen. The strategy with this bit is that in normal drilling only the cutters contact the rock for maximal point loading. In the event of any dysfunction pushing the bit outside of normal drilling, there should be overwhelming engagement from support components. This ensures that the bit is normally highly efficient but that in the event dysfunction occurs, the excess energy is shared over a large number of parts.

The bit uses replaceable inserts made from an impreg like material which are designed to wear into the shape of the groove following the cutters. Once worn in, they provide a bearing surface that only instantaneously engages in the event of dysfunction. These parts have been shown to reduce vibration. Because these components are designed to wear, they are most effective in the middle part of the run, and generally being replaced in repair. These parts are placed near the centreline of the bit to smooth torque and on the shoulder of the bit for lateral vibration control.

3 sided PDC pyramid components have been placed in the shoulder region at the back of the blade. These parts track the cutter in front and are placed slightly off tip to ensure that in normal operation they don't contact the formation. They are placed at the back to offer most protection in the event of backward whirl. These parts have an impact resistance around 3-4x that of the cutter in front and, critically, the pointed shape ensures that there is only a small increase in contact bearing area with the rock when they are engaged. Additionally, pyramids are useful in the event of overload of a cutter to prevent a single cutter failure turning into a ringout. For these reasons pyramids serve a dual purpose; load sharing impact energy and also ringout prevention.

Final design choices included furnishing the bit with 6 sleeved nozzles and Computational Fluid Dynamic software was used to iterate the nozzle position until an optimal fluid flow for cleaning and cooling was achieved. A 3" gauge was used to ensure that full directional control is possible. At the end of each gauge pad, a cylindrical PDC cutter of premium grade is used. Use of the same premium grade cutters in all locations in key in this bit as the heterogeneous formation and high energy system can result in unpredictable failures.

5.4 Body material

There are generally two different choices of material for the body of bits: steel with wear resistant hardfacing or matrix, a sintered tungsten carbide bonded by a nickel based alloy. Matrix bits are generally more abrasion resistant but are more prone to brittle failure leading to blade loss compared to steel. At the start of 2026, tungsten prices have increased such that a matrix body has become 100% more expensive than the 2025 price or over 200% since the relatively stable 2014-2024 period. This can make a matrix bit over twice the price of a steel equivalent bit.

Given the vibration prone environment and availability of hardfacing enhanced with diamond grit, this bit uses steel as a body material.

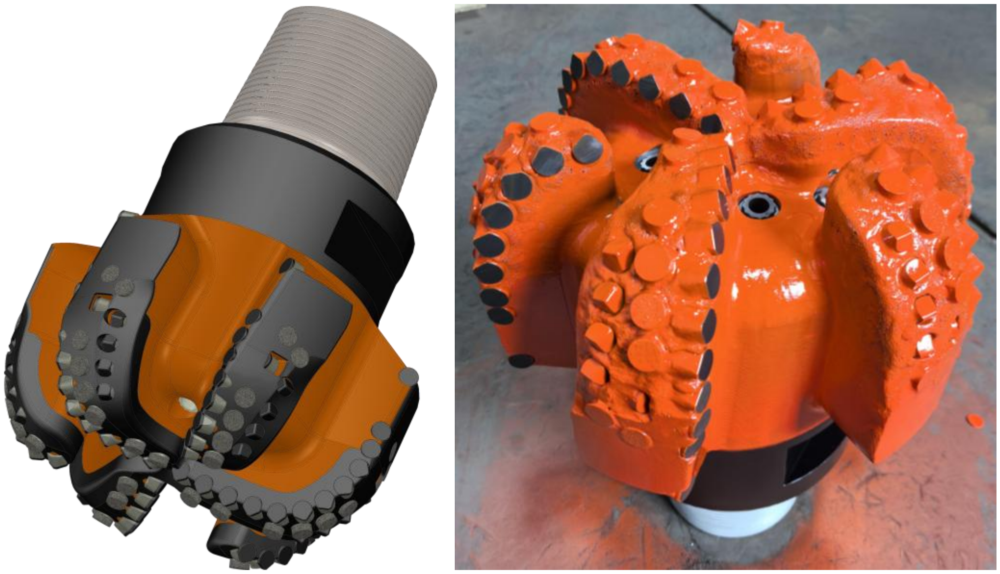

Figure 3 - The finished bit design with nomenclature 12.25” DB616. This is part of the CS-0013 family.

6 FIELD PERFORMANCE RESULTS

6.1 Drilling operation

The bit was run on a bent motor to perform the planned directional work for over half of the total interval with this bit. The bit was run with a TFA of 1.035in², giving an HSI of 1.3.

Offset mud logs showed the following rock types present during this bit interval: Tuff (15%), Andesite (28%), Ignimbrite (30%) & Rhyolite (27%). Rocks such as Rhyolite and Ignimbrite are highly abrasive due to a high silica content. Furthermore, these were highly interbedded. Confined compressive strength was around 45ksi and Mohrs hardness between 6-7. The rock in this interval was approximately 190°C.

6.2 Performance

The bit drilled 1,952ft (595m) at an average ROP of 46ft/hr (14m/hr). Most of the interval, 64%, was drilled in rotary mode, while the remaining 36% was in sliding mode. In rotary mode the average ROP was 54ft/hr (16m/hr) while in sliding it was 33ft/hr (10m/hr). It should be noted that the bit was ROP limited at various points in the first half of the run as can be seen in Figure 4. The torque signature of the bit was relatively smooth from 4,225 until 5,700ft depth where the torsional vibration begins and continues for the next 400 ft. There was also reported to be weight hanging at end of the run and an inability for the motor to slide which was suspected to be due to a spiralled wellbore. A reaming operation was carried out before the following bit run.

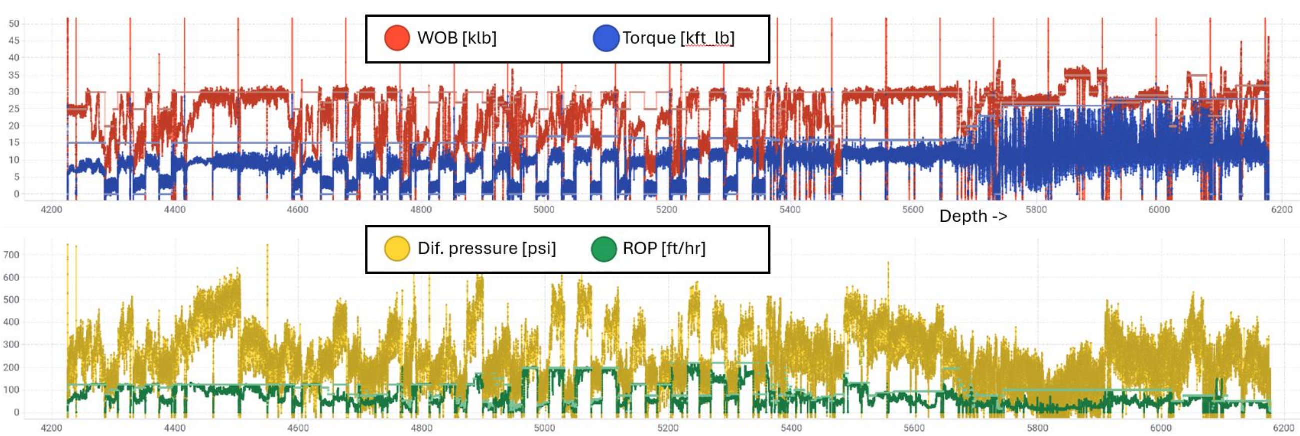

Figure 4 - Depth based weight on bit (WOB), torque, differential pressure and on bottom rate of penetration (ROP). This information covers the whole run and shows the performance throughout the interval.

Compared to offsets, the DB616 achieved 258% ROP improvement, and 124% interval increase where the average offset ROP was 12.9ft/hr and the interval was 872ft.

6.3 Post run condition investigation

The BHA was pulled for a planned change of motor due to hours. The bit was dull graded as 1-3-CT-G-X-I-WT-BHA. Without the BHA change, the bit is fully repairable or still capable of drilling.

Figure 5 - Post run condition of the bit.While wear can be observed in various areas, the bit is still functional and repairable.

6.3.1 <u>PDC cutter wear</u>

Between 0-60% bit radius (bit centreline to nose) wear is minimal. This demonstrates that the region was correctly chosen to be more aggressive and to make the bit more efficient overall.

Between 60-80% radius (upper shoulder region) the predominant damage was impact related. 37% of cutters in this region have suffered breakage with complete loss of diamond table. It is notable that over the whole bit 78% of the cutters with a dull grade of 8 (no remaining diamond table) have no pyramid support component behind. This supports the previous suggestion of the impact protection provided by these parts. Also importantly, where the pyramid support components have been behind the cutter they have prevented the overload of a single cutter turning into a ringout; the only two PDC that broke in order on the spiral layout did not have any intervening pyramid.

Between 80-95% bit radius (shoulder-gauge transition), the predominant wear mode is thermal abrasion (present on 74% of primary cutters). This is normal wear seen on bits, but it is impressive that only 26% of cutters suffered impact damage (CT, BT) given the vibration prone nature of the application. This is likely to have occurred in the torsionally unstable section in the final 20% of the interval.

For gauge cutters, 42% of cutters have completely lost the diamond table. These are not evenly spread; blades 1 and 5 lost all gauge cutters while blade 4 only lost the first cutter. All other gauge cutters are unworn. This suggests massive lateral impact. Notably, the preceding scribe cutter on each blade is undamaged. On blade 5, the backup cylindrical cutter is also severely damaged further strengthening the idea that regular cutters are sub-optimal for choice as support components. Fortunately, on all blades, the choice to use premium cutters for all uppercuts has helped ensure that the bit remains in gauge.

It is likely that all vibration damage occurred near the end of the run. Figure 6 shows one of the cutters with the diamond table completely removed. Comparing the wear scars on only the carbide for the 3 cutters shows normal abrasive wear progression. If the diamond table were lost much earlier in the run the carbide wear scar would be much greater than cutters either side with intact diamond tables.

Figure 6 - A broken cutter on blade 4 shows commonly growing wear scars between adjacent cutters irrespective of the missing diamond table. This cutter is located on the nose and the centre of the bit is to the left in the image while the gauge is to the right.

6.3.2 Gauge pad wear

The highly abrasive nature of the formations such as rhyolite, combined with a bent motor has resulted in wear of the gauge pad. The worn gauge pad likely resulted in higher lateral vibration but lower torque. Use of high specification uppercuts can be observed as these have not worn at all and the hardfacing trailing is intact which helps maintains a stabilising point on the gauge pad.

The bit is considered fully repairable; with application of new hardfacing and replacing cutters and inserts, the bit would be ready to run again.

7 FUTURE DEVELOPMENT & OPTIMISATION

The fundamental design of the bit is correct; many of the correct choices were made for the application. Having seen the dull condition of the bit there are two areas of refinement and one upgrade.

1. The nose-shoulder region was not protected by pyramids and this is where most face damage occurred. Additional pyramid elements have been added here to reduce impact damage. The small number of secondary PDC cutters on the bit were proven to fail under load and so these have been replaced by more reliable elements.

2. The gauge saw lots of damage. Cutters either suffered total failure from impact or no damage at all. Additionally, the hard facing on the gauge pad was worn. This is the area of greatest re-design. The two rows of gauge cutters have been widely spaced out to give total gauge pad coverage and the second row has been given an even more passive backrake to enhance impact durability and ensure the gauge is very passive. Further, wedge shaped components are placed trailing each gauge cutter. These are better able to absorb impact damage due to their greater load bearing area, but are less able to cut rock than pyramids (which is less important in the gauge of the bit than the face).

3. Finally, PDC grades are always improving. The rest of the 12.25” section sees less impact risk, but point loading is critical. All enhancements so far improve impact resistance to ensure that the previously drilled section can be drilled with less damage, but to drill the lower section efficiently, the cutters must stay sharp. For this reason, a newer grade shall be chosen that has a small improvement in impact resistance, but higher thermal abrasion resistance.

It is expected that the new design will be able to drill significantly further with a realistic goal of drilling the 12.25” section with a single bit run.

Figure 7 - Revised bit design, nomenclature 12.25" DB616 and is part of the CS-0118 family.

8 LEARNINGS FOR OTHER GOETHERMAL WELLS

Choice of drill bit is critical to the success of drilling. If choosing a drill bit for a similar well, the following should be considered:

- If impact damage is expected, the bit should be hardened against this specific failure mode.
    - Blending: while the more common thermal-abrasion damage is easier to predict the location, impact damage can occur anywhere. For this reason, blending cutter grades should be avoided and the same high grade should be present in all locations.
    - Support components; these should have higher impact resistance than the primary cutter to avoid a single hard nodule breaking multiple cutters in spiral and causing ringout. It is unlikely that a secondary cutter will have greater impact resistance than the primary cutter in front of it. As such, secondary cutters are rarely the best choice for impact prone environments.
- Efficiency is key. In normal operation, the bit should be highly efficient. This means less energy is translated into counter productive dysfunction generation. This requires consideration of the idea that a bit with more blades may be less durable.

9 CONCLUSIONS

The bit designed for this application successfully drilled a hard 1,952ft (595m) interval of hard and abrasive interbedded volcanic rock with CCS of 45kpsi, at an average ROP of 46ft/hr (14m/hr) and was tripped for BHA change. The bit was still functional and was in a repairable condition. This represented an increase compared to the offsets of 258% for ROP and 124% for interval.

This performance validates design assumptions about cutter force distribution and vibration control in this challenging lithology. Furthermore, the choice of an efficient 6 bladed PDC bit with support components is shown to yield excellent results.

While this performance is considered excellent given the difficulty of the lithology drilled, durability improvements have been highlighted to help this bit drill the entire section in a single run.

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