How to Design, Iterate and Continually Improve PDC Drill Bits for Geothermal Drilling

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ABSTRACT

Geothermal Drilling is a high-cost operation and has a large upfront cost to any new power station project. Drilling a well requires setting a series of casing strings that are drilled to a suitable depth to provide pressure containment of the surrounding wellbore fluids. The production section is normally a longer open hole section and is drilled to access a geothermal reservoir. This is typically the most challenging section to drill and complete.

Successfully drilling each section, requires an understanding of the geology, wellbore and formation hazards or challenges as well as the directional objectives. A wholistic approach is required to assess the optimum drilling strategy to complete the section with minimal cost. This is usually achieved by minimising drilling days in the form of increased rate of penetration (ROP), however can also be achieved by minimising drilling tool wear and reducing open hole risk and potential hole problems.

This paper focuses on Polycrystalline Diamond Compact (PDC) drill bit design, selection and iteration processes to increase rate of penetration and subsequently reduce cost per meter drilled in geothermal operations. It will detail offset analysis techniques, dull grading and cutter failure mechanism recognition, drill bit manufacturer selection, continual improvement design iteration processes and drilling parameter optimisation.

A good geothermal drilling strategy is balanced by utilising a well-designed custom drill bit, followed by suitable bottom hole assembly (BHA) selection and then drilled with ideal parameters – weight on bit, flow rate & revolutions per minute (RPM). The output of successfully completing this, results in smoother drilling, a bit that stays sharper for longer, and less accumulative tool & drill string wear by minimising on bottom drilling hours.

This paper will demonstrate how to analyse and execute a custom drill bit design and drilling strategy that will suit your field and application.

1. KNOWING YOUR APPLICATION

1.1 Offset Analysis Data Collection

Offset analysis is critical in understanding the hazards and challenges of your application. Understandably, in geothermal, there is not always the best data quality available or relevant nearby wells to gather information from. However, using all data available is required to establish limiting factors, drilling dysfunctions, benchmarks and key improvement areas. This will form the primary design objective for creating a bespoke PDC bit design suitable for your application.

The first step in offset analysis is to locate the nearest wells. These may be wells drilled by your company, or by another geothermal industry operator. If data sharing is available, requesting insights and performance metrics of offset wells is a good starting point.

Basic well information includes surface location, maximum depth, hole trajectory and elevation. These are required to ensure an anti-collision assessment can be performed. Occasionally, some old wells may require a gyro survey to understand well trajectory if surveys were not taken at the time of drilling. This should be accounted for in planning stages as it requires time, effort and money to log. Alternatively, if the offset well is low risk to the new well plan, special sign off can be permitted between the directional drilling contractor and the operator.

Next, group offset wells into relevance for your planned new well. Focus on wells first with similarity to the new design such as section depths, formations drilled and hole diameter.

Detailed offset analysis includes assessing the following data:

1. Drilling depths-based data – this includes parameters such as depth (measured and true vertical), rate of penetration (ROP), weight on bit (WOB), revolutions per min (RPM) for both motor and surface drill pipe, torque, flow rate (in and out), standpipe pressure, mud weights (less important in geothermal), air rate (if used) and returns status.
2. Drill bit record – sizes, bit type or model name, serial number, depth in and depth out, dull grade, nozzle information.
3. Geology information – formation tops, lithology type, characteristics such as abrasion, hardness, alteration, pebble size and swelling tendency.
4. BHA information – motor specification (output curve and differential pressure), special tools (friction reduction tools, shock tools, roller reamers, active stabilisers or trimming tools), measurement while drilling (MWD) tools.
5. Survey information and MWD analytics (temperature and vibration data)
6. Drill bit dull photographs (pictures taken after a bit is used downhole). These are excellent for design engineers as it far more accurate that dull grade. It is used to determine the cutter failure mechanism and primary type of wear (abrasion, thermal, impact). Photos are also able to highlight any non-cutter wear including body erosion and abrasion and blade wear. Bit dull grade can be used in replacement of photos if nothing is available.

This may seem like a lot of information but once the data is streamlined into a spreadsheet, it becomes a valuable tool, to easily identify opportunities for improvement.

The outcome of good offset analysis is to identify key improvement areas for your upcoming drilling campaign. The focus of this paper is on drilling strategies and specifically PDC drill bit design, selection, improvement and iterations. However, drilling tool selection, wellbore inclination, casing sizes, cementing techniques and air drilling practices can all be improved to increase performance and reduce total cost per well.

1.2 Drilling Optimization Spreadsheet

Contact Energy has developed a Drilling Optimisation Spreadsheet to identify formation specific statistics, drilling trends and display calculated variables such as Standard ROP and Mechanical Specific Energy (MSE).

Inputs include depth based data, drill bit record and formation top depths to create several drilling graphs and formation property benchmarks.

Standard ROP has been developed by Ralph Winmill, Contact Energy, to display a rate of penetration that is standardised back to 2000lbs per square inch diameter and 80RPM. The formula for standard ROP is shown below:

$$St\ ROP = ROP \times \frac{2000 \times Bit\ Diameter}{WOB} \times \frac{80}{RPM}$$

St ROP (m/hr), ROP (m/hr), Bit Diameter (inch), WOB (lbs)

St ROP is plotted on a logarithmic scale X-axis and is used by Contact Energy to correlate the formation hardness and ability to drill. It also provides a comparison between two competitor bit types that may have used different input parameters. Lower St ROP value indicates harder rock and higher values indicate softer or easier formation to drill.

MSE was first proposed by Teale (1965) and has been used by the Oil & Gas industry for many years. Contact Energy has been using the MSE concept in drilling performance to identify any trends which can be attributed to drilling inefficiencies including bit dull, poor cuttings evacuation and vibration.

MSE is calculated by the following formula:

$$SE = \frac{WOB}{A} + \left(\frac{2\pi}{A}\right)\left(\frac{NT}{ROP}\right)$$

This formula is comprised of two parts. Firstly, the thrust force component which is weight on bit (WOB) divided by Area.

The second component is the rotary speed component, N being rotary drill string speed and T rotary torque of the drill string. These values are measured at surface, ROP is measured in inches per minute.

The use of St ROP and MSE can be used to highlight trends or identify times where drilling becomes inefficient, and a bit trip could be considered. The goal of using these tools is to determine your objective or drilling strategy and benchmark the offset data.

The spreadsheet should also display a formation breakdown per bit, including interval drilled, WOB, torque, RPM, standpipe pressure, flow rate and ROP. This provides a quick assessment if there are any formation dependent performance trends that can be identified and then optimised.

Development of a similar spreadsheet or drilling performance tool is necessary to ensure the best chance of successful design iteration. Focusing on what areas can be improved to ensure successful design changes is critical. This could be to increase the total interval drilled, improve dull condition, increase ROP, prevent drilling disfunctions, or have better steerability/ toolface control.

1.3 Dull Grading

The International Association of Drilling Contractors (IADC) dull grading system was created by the oil & gas industry in 1987. It was then updated in 1992 to include fixed cutter dull characteristics and to increase effectiveness of the dull grading system (Brandon, 1992). Since then, it has been widely used in oil, gas and geothermal operations around the world to describe a bit's dull condition through an eight-character grading system.

This is displayed as:

- Inner rows cutter wear in 1/8th
- Outer rows cutter wear in 1/8th
- Primary/Major Dull Characteristic
- Location of Major Dull
- Bearing & Seal Life
- Undersize of Gauge in 16th of an inch
- Other Dull Characteristic
- Reason Pulled

This is written as one line and used to paint a picture of the drill bits used condition. An example shown in Figure 1, is graded 0-1-WT-S-X-I-NO-TD.

Figure 1: Picture of used PDC drill bit used in a Contact Energy, New Zealand Geothermal Application

This grade represents the bit was in good condition with 0/8 wear on the inner rows (0), 1/8 wear out the outer rows (1), worn teeth (WT) was the primary dull, located on the shoulder (S), X represents the grade given to PDC bits due to lack of bearings, the bit was in gauge (I), there were No Other (NO) dull characteristics, and the bit was pulled for Total Depth (TD).

This paper does not focus on how to dull grade PDC bits. More information on how to grade correctly and subjectively can be read about in Brandons (1992) paper linked in the references.

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A recommended PDC grading approach for designing bespoke bits, is to perform a cutter by cutter failure analysis. This can be completed in person or from very clear large photographs of each blade. This provides a higher level of understanding of failure mechanisms and the potential features required to achieve a great PDC bit design.

1.4 Cutter-by-Cutter Failure Analysis

A cutter-by-cutter analysis is an individual assessment of each cutter across a blade. This type of analysis will result in a better understanding of the dull condition of your drill bits and result in an improved PDC bit for your application.

To assess each cutter, a basic understanding of cutter failure mechanisms is required. If this is not your area of expertise, generally bit vendors (see section 2) can assist in dull evaluation and primary failure mode as part of the design service.

The components of a PDC cutter are shown below in Figure 2. The cutter shape can vary greatly depending on the bit manufacture and patents.

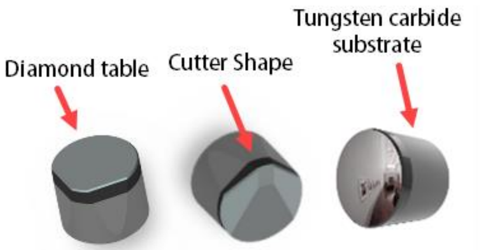


Figure 2: PDC Cutter Components. Credit: NOV ReedHycalog supplied image.

The basic cutter failure mechanisms are:

Broken Cutter – tangential fracture, front faced overload or hinge failure (diamond table axial failure). This type of failure does not necessarily have to penetrate through the cutter substate, it can be solely through the diamond table. This failure mechanism is typically caused from impact damage from one event or a combination of: interbedded formation, high WOB, bedding the bit in too quickly, hard formation, junk damage or caused from drill out.

If this type of failure mechanism is seen, a focus on cutter toughness and impact resistance can be looked at. Other considerations are the length of the cutter substrate and the cutter backrake angle.

Figure 3: Picture of Broken Cutters. Front faced overload (left) and tangential diamond table fracture (right)

Chipped Cutter – spalling, delamination and impact chips to the diamond table. These can either be located at the cutting tip of the cutter or isolated in the center of the cutter. Chipped cutters can also exhibit normal wear flats as shown by Figure 4. The cause of chipping can either be thermal degradation of the diamond table, front faced impact damage or a combination. Figure 4 demonstrates thermal degradation spalling of a PDC cutter. This is shown by the "beach wave" type marks starting from the tip of the cutter and progressing towards the center of the diamond table. It is also demonstrated by the smooth wear flat on the adjacent cutter.

If this type of failure mechanism is seen, a focus on cutters with thermal stability properties and durability should be considered.

Figure 4: Picture of chipped cutters exhibiting thermal degradation.

Ring out – this is where a complete spiral of cutters is missing from each blade. This failure mechanism increases overload on the adjacent cutters and subsequently causes premature failure in the form of broken cutters. A ring out can be caused from lack of diamond volume on the shoulder & nose, too much WOB, or improper selection of cutter toughness for the application.

The nose and shoulder cutters are a critical design element for PDC bits. This area has the highest load when drilling due to a combination of large volume of rock to shear and high velocity to turn one revolution. More on how to design the nose & shoulder adequately can be read about in Section 2. A ring out can be seen in Figure 5 on the shoulder of the bit. The cone is in good condition and the bit was measured in gauge.

Figure 5: PDC Bit Ring out on the shoulder

In Figure 6, the adjacent cutter (C1) has experienced impact failure due to increase loading when the shoulder cutters have been worn down to the blade height. The ring out cutters (C2, C3) have also experienced delamination of the diamond table due to excessive thermal wear.

To minimise ring out risk, increase diamond volume on the nose and shoulder of the PDC bit by; increasing blade count, reducing cutter spacing, increasing shoulder length or decreasing cutter size. Cutter grade and shape can also be tailored to minimise ring out risk. Shaped point loaded cutters are tougher than cylindrical cutters in this position for example. Secondary components that are impact resistant (conical shaped inserts/buttons) can also assist.

Figure 6: A close up of the same PDC bit in Figure 5 showing impact damage to cutter 1 (C1) and delamination of the diamond table on cutter 3 (C3). Ring out occurred across C2 & C3 which is located on the shoulder of the blade profile.

Worn Cutter – this is a normal dull mechanism and is a baseline test for new cutter technology performed on a vertical turret lathe (VTL). The cutter will show a wear flat across the cutting edge where it engages formation. The goal for any premium or new cutter grade is to delay the onset of the first wear flat to maintain a sharper cutter for longer.

If your bit exhibits only worn cutters, the design can be improved by either newer cutter grades or an improved shape that scores high in durability and thermal stability. Typically, new cutter grades are released commercially on an annual basis from bit manufacturers.

Figure 7: Worn Teeth even wear flats across all cutters. No indication of thermal wear indicates only abrasive wear mode. This is considered a normal dull mechanism.

Other things to note about failed cutters:

Is there heat checking? Heat checking is a form of thermal wear from heating and cooling of the cutter substrate. It is typical of stick-slip vibration which is a very damaging form of vibration to bits, tools and drill string. This type of wear is shown in Figure 8 below.

The primary solution to avoid this type of wear is to mitigate the vibration mode causing it. This can be done through vibration modelling, real time parameter optimisation and vibration mitigation while drilling. Cutters with high thermal stability can delay the start of a wear flat, but if stick slip vibration is present, most cutters will fail early. The use of secondary torque control components can assist with minimising torsional vibration by limiting depth of cut (DOC).

Figure 8: Stick slip vibration heat checking located on the tungsten carbide substrate

No Dull – this is the best kind of grade for a cutter. This is when the bit is pulled in near perfect condition. The only thing missing is the paint. Drill bits which exhibit no dull or very little wear are typically great performers as the bit maintained a sharp cutting edge for the entire interval.

Figure 9: 12" PDC Bit Dull in Geothermal Application, NZ

Considerations about bits with no dull are:

1. Is the bit design too durable? Could the blade count and diamond volume be reduced to create a more aggressive PDC. This is important to consider if the bit performance (on bottom ROP) was a little lack lustre. Decreasing cutter volume reduces durability but increases aggressivity.
2. Is the grade of PDC cutters being used too premium? Could a cheaper cutter be considered? I do not recommend using Tier 2 or Tier 3 cutters in harsh geothermal applications, but in some cases, dropping to a cheaper cutter can have a significant reduction in bit cost. This is more important for large diameter PDC bits where there is a large cost in the cutting structure alone. The 20 ¾" TKC89 bit "Kraken" designed for Contact Energy drilling campaign has been rerun in 16 wells and accumulated 5265m of drilling, uses a Tier 2 cutter as an example.
3. Is the objective to be able to rerun the bit? If so, a no dull grade is an excellent achievement. Besides cutters, PDC bits are only limited by body erosive wear which is a function of hours, hole geometry, solids content and flow rate.

The above section has highlighted the primary cutter failure mechanisms to identify and aid design and continuous improvement for PDC bits in geothermal applications. There are other dull characteristics to also include in offset analysis if apparent. These include erosion, lost cutters (usually a manufacturing fault), junk damage, broken blade, lost nozzle, cored bit and balled up.

Once the primary failure mechanisms of cutters have been assessed and understood, new design iterations can begin.

2. DESIGNING A PDC DRILL BIT – THE STEPS

This section outlines the steps to design a PDC drill bit for your application with your chosen bit vendor. Multiple bit vendors can be selected but there are long term advantages of working with 1 or 2. These include building strong relationships with your account manager, streamlined bit iterations, the bit vendor builds application knowledge and expectations are understood.

2.1 Design Objective

After offset analysis is complete, the design objective is created for your project. This objective determines your benchmarks and criteria for your PDC bit with the bit vendor.

Directional Objective

Directional flexibility in a bit design can be advantageous to swap between rotary and motor BHA's. The directional component of a drill bit include the gauge length – typically between 3-4 inches, the gauge taper, the blade profile, the number of gauge cutters, and the cutter density between shoulder to gauge. The bit design engineers will determine what elements and features are required for the application. You are required to provide them with the following information:

- Motor Specification Sheet and planned bend setting
- Planned build up rate (BUR) and final inclination
- Formation characteristics and hazards
- Previous dull grades on bent motor BHA's

Ideally in geothermal applications a bend angle between 0.78 – 1.15 is commonly used. The larger the bend, the more critical the bit design needs to be matched to the motor.

Performance Objective

What is the primary goal of the application? Consider directional stability, performance increase, torsional control, enhanced durability, rerunability, repairability and better hole quality.

As the customer you need to highlight the primary objectives, followed by the secondary objectives. This could look like the following statement:

12 ¼" PDC bit with directional stability and good toolface control on a bent motor as primary objective, followed by durability/better looking bit dull and increased performance (ROP) third. This allows the bit engineer to optimise the cutter density, blade profile, cutter grade and shape, backrake angles, secondary components and gauge length in order of importance.

Limiting factors

The limiting factor of the application is important to highlight as not all applications are bit limited. This may include a downhole drilling tool temperature limit, directional/BHA change point, max circulation hours or drill string and tool wear hours. It could also be a reservoir constraint for staged injectivity test. This may change the way you consider your application and design choices.

Bit Selection Technology – RC, PDC or Hybrid.

This paper focuses on PDC bit design, however all the steps outlined can be used to determine if roller cone, PDC or hybrid technology is best suited for the application. The same steps are required for each type of drill bit.

This paper does not go into detail about hybrid drill bit designs (combining roller cones and PDC blades), however it is important to consider the bearing life, rerunability, performance and purchase price to determine if this type of bit technology is worth pursuing. Due to the complex design of hybrid bits, they typically have premium costs associated to them. This can make them uneconomical in some geothermal applications but not always.

2.2 Blades & Cutter size

The bit designer will aid in selecting cutter density (blade count) and cutter size once the application is understood. The relationship between blades and cutters is this:

Larger cutters are more aggressive resulting in higher ROP but less durability. Smaller cutters are less aggressive, but due to the small depth of cut taken per cutter, they are more durable. Below is the range of sizes that are offered.

Figure 10: Cutters sizes left to right. 8mm, 11mm, 13mm, 16mm, 19mm

Note that there is very little active development being done for cutters smaller than 11mm. 16mm cutter development is highly competitive and generally where the highest performing cutters are seen.

Cutter count (sometimes referred to as blade count) is a relationship between durability and aggressivity. This is generally because you can fit more cutters on more blades, which increases diamond volume. The tighter the cutter spacing and higher the blade count the more durable a bit is. The larger cutter spacing & lower blade count increases aggressivity.

A good balance in 12 ¼" geothermal applications from Contact Energy's experience tends to be 6-7 blades and 16mm cutters.

2.3 Secondary Components

Secondary components are parts that sit behind the primary cutting structure either directly behind the cutter or offset in between. These components can increase durability, add torsional stability and limit depth of cut (DOC) to prevent cutter breakage and reactive torque.

Secondary Cutters

Secondary cutters are a row of additional PDC cutters that sit behind the main cutting structure. This adds diamond volume and redundancy to the primary cutting structure, however there is not a lot of evidence that it increases durability. Secondary cutters have been used in the early adoption of PDC bits to increase cutter count, but as PDC cutters have become more robust, the need for secondary cutters is decreasing. It is much better to utilise other secondary components in geothermal operations for torsional control and lateral support.

If secondary cutters are used, they are set off-tip and only engage minimally once a wear flat is established.

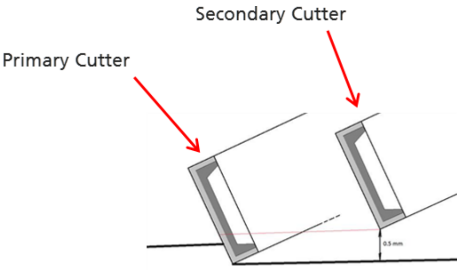


Figure 11: Secondary cutter placement behind primary cutters with 0.5mm tip offset

Other Secondary Components

Dome buttons either made of tungsten carbide or tipped with PDC are used for torsional stability and depth of cut control. When placed on the shoulder or gauge, they can also provide support against lateral vibration and gauge wear.

There are also elements called Diamond Impregnated Material (DIM's) or High Density Impregnated (HDI) material that are made from very small synthetic diamonds mixed evenly through a metal alloy matrix.

These elements provide different advantages depending on the geology and application needs. The bit designer will provide justification and suggest which secondary components should be used. The tip offset can be adjusted to increase or decrease aggressivity for the application.

2.4 Body Material

Two body materials are offered for PDC bits, either matrix or steel. Matrix body is used for erosion resistance and in the past, been selected for bits that require multiple repairs. However steel bits and enhanced hardfacing are also becoming popular repair options recently. Matrix bits are made from tungsten carbide and binder material and melted in a graphite mould to create the bit body. The graphite moulds are one time use, and therefore matrix bits are substantially more expensive than steel bits. Matrix body is only available in sizes 16" and smaller. A matrix body bit should not be ordered unless finite element analysis (FEA) has been completed as matrix blades can be prone to breakage.

Steel body is used for large diameter PDC bits, dual diameter and standard diameter PDC bits. The steel is milled to the profile required and hard facing is added for erosion resistance. Steel bodied bits are easier to manufacture and make design changes to as they do not require a mould. Early technology hardfacing used to be inadequate protection for high flow rates and air drilling practices, however new hardfacing is very robust and can be effective in geothermal drilling.

2.5 Other Design Considerations

There are several other design components to a PDC bit which are too specific for this paper and are generally outside of the knowledge required for operators. These items include:

- Leached cutters – leaching technology (where the cobalt catalyst is removed from the diamond table) was developed in the early 2000's by NOV. This was revolutionary at the time as it increased the durability and thermal stability of PDC cutters which made them suitable for geothermal applications. Non-leached cutters should not be used in geothermal applications.
- Back rake angle – this is the angle the cutter is placed into the cutter pocket and cuts formation at. The higher the back rake the more axially resistant the cutter, the lower the back rake the more tangentially impact resistant.

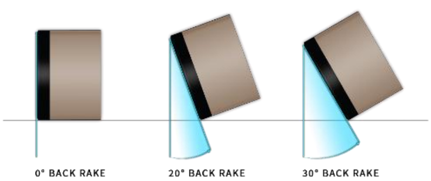
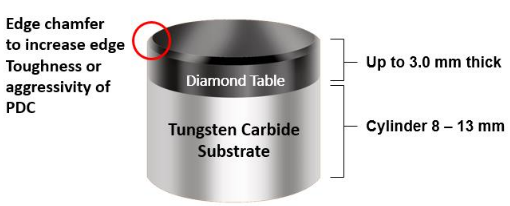


Figure 12: Cutter Back Rake Angle

- Cutter chamfer and diamond table thickness. Chamfer degree is used to increase impact resistance or aggressivity of the cutter. Diamond table thickness increases thermal stability and leaching depth available. Geothermal applications suit a diamond table thickness of 2.5mm and leached a minimum depth of 400µm.



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- Blade profile and cone angle. The blade profile is the length of the blade arch from cone to gauge. A longer shoulder can increase durability and a flatter or shorter profile can increase steerability. The cone angle is how deep or shallow the cone cutters are. Deeper cone increases stability and shallow cone increases steerability.

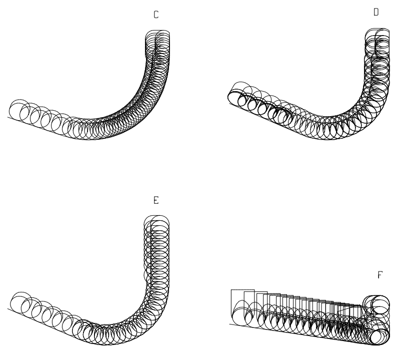

Figure 13: Blade Profile differences and cutter density across all blades.

- Cutter shapes are also important in geothermal drilling. Lots of cutter shapes are being brought to market by different bit vendors. The shape used is dependent on the application and offering available to the bit manufacturer. Various SPE papers are available on the advantages of shaped cutter technology, these will be included in the additional reading section.

3.0 FINDING A BIT VENDOR

There are 4 major competitors for PDC bit manufacture who can provide bespoke design drill bits and have access to excellent cutter grades, shapes and design features. These companies' regularly test new premium cutter grades either inhouse or through third party vendors. The tests commonly performed are dynamic drop testing for impact resistance, vertical turret lathe (VTL) test which measures wear resistance and thermal stability, tangential and axial to determine cutter toughness. These tests allow for cutters to be graded across 5 indices (4 wear and 1 economical). These are durability, impact resistance, toughness, thermal wear and cost.

A cutter cannot typically be graded high across the four wear indices. If a cutter is made to be extremely durable and thermally resistant, it may have lesser impact resistance and toughness. Therefore, it is important to highlight the true application needs of each drill bit to ensure the right cutter is selected.

The four major drill bit manufactures are:

1. Baker Hughes
2. Halliburton DBS
3. NOV ReedHycalog
4. SLB (Schlumberger)

The advantages of selecting a bit vendor from the above list include:

- Extensive research and development on new cutter technology, making them more likely to provide better options for harsh applications
- Huge selection of existing bit designs plus ability to design bespoke bits from scratch
- Inhouse cutter & rig testing
- Access to exclusive premium cutter grades and shapes
- Large market share and run history globally with proven runs across multiple applications
- Can usually offer PDC bits on consignment if large purchases are made.
- Access to repair facilities globally

The disadvantages of selecting a big four bit vendor include

- High purchasing cost
- Longer lead times for design and manufacture
- Availability of design engineers due to Oil & Gas operators typically taking priority
- Requests for bespoke PDC bit designs can be rejected if market share or quantity of bits required is too low.

There are other smaller bit manufacturers that can provide operators with suitable PDC bit designs for geothermal drilling conditions. These companies have access to similar premium cutter grades through cutter vendors such as US Synthetic and Element 6. These companies include:

1. Ulterra
2. ZerdaLab
3. Stealth

The advantages of selecting a bit manufacturer from the above list are:

- Lower bit purchase price
- Quick turnaround time for design manufacture
- Eagerness to provide excellent customer service
- Willing to design unconventional bit designs
- Typically, able to accommodate small design changes (like cutter grade and shape) quickly

The disadvantages of these bit manufacturers include

- Limited inhouse testing for cutters or new bit designs
- Specialist analysis such as cutter force model, computational fluid dynamics (CFD) and FEA may not be available/too costly to perform.
- Repair facilities could be limited
- Design engineers may not be able to accommodate huge design changes if software is not available.
- Usually less capital available to spend on R&D projects
- No access to branded features or secondary components that are patented by the big four

Selecting a bit vendor is a subjective process and not limited to a single company. Work with a company that can provide a great service and design commitment that is required for your application and drilling objectives. Using the techniques and guidelines written in this paper, can aid in proper bit selection to improve performance and reduce overall well cost.

4.0 ITERATIONS

Once your new PDC bit is designed, purchased and manufactured, it is time for baseline performance results and the start of your continuous improvement journey.

Regardless of how good and well executed the initial bit design is, there is always something to learn and a better drill bit option to be made. There is nothing more satisfying and nerve racking, then to drill with a bespoke designed PDC bit in your field. The run data will provide new benchmarks and performance indicators that can be used to improve the design and overall reduce cost of your geothermal wells.

If the design underperforms compared to offset data, it is important to understand the underlying reason. There are various factors that can influence performance and rate of penetration including drilling parameters, vibration, lithology, BHA components, stabilisers sizes and directional requirements. The bit designer and vendor can work with you to determine the reason for underperformance and if there is any clear failure indictors that may have attributed to the poor performance. In general, it is better to trial a bit design twice before discounting the poor performance. This allows an objective view of how the bit performed and if there was a design issue or a drilling dysfunction issue.

Iterations for bit designs range from simple to complex. Simple design changes include changing cutter type and shape and optimising nozzle sizes. Complex changes include adjusting gauge length, blade profile, secondary component changes, nozzle numbers, number of blades and cutter sizes.

Not all these design changes should be completed at once. It is encouraged to only make 1 or 2 changes at a time to ensure the changes are creating a positive impact to your application.

Once a design is meeting or exceeding your expectations, design changes do not need to continue as often. A repair schedule may be a more economical option which includes repairing all the primary cutters and/or secondary components to new and repairing any hard facing required. PDC bits can be repaired at least twice before considering retirements due to thermal cutter cycling that repair bits experience.

5.0 CONCLUSION

This paper has discussed the fundamentals of PDC bit design and how to develop a bit that is right for your application. The basis of good drill bit engineering is to understand the hazards, challenges and objective required to meet your campaign goals.

Offset analysis, benchmarking and setting realistic expectations is the first step to understanding the goalposts and where improvements can be made in terms of drilling performance.

The dull grade or cutter failure mechanisms of previously used bits, both roller cone and PDC bits, can provide insight into what design factors are most critical. This includes cutter characteristics – size, shape, grade, chamfer and leaching depth, as well as secondary components and blade profile to best handle the primary failure mode in your application.

Selecting a bit vendor is also an essential step in starting your PDC design and iteration journey. More than one vendor can be selected which provides variety to use different cutters, grades, shapes and features that are exclusive to some manufacturers. An important consideration is to find an account representative and vendor that meets your expectations and displays excellent customer service to provide confidence in the bits you purchase. Continuous improvement and design iterations are necessary to ensure the design continues to adapt to challenging environments and to reduce overall cost to your geothermal operation.

All these steps can be used repeatedly in different fields to develop a suite of PDC drill bits that can used in geothermal applications. As cutter technology gets better throughout the years, other features may become less critical including secondary cutters or torque control components. Bit venders also release innovative new designs such as the Kymera™ from Baker Hughes & Pegasus™ series from NOV. These types of bit designs push the boundaries of conventional PDC designs and provide solutions to challenging applications worldwide.

Geothermal drilling is becoming increasingly relevant as the world continues to decarbonize and increase energy output globally. Ensuring we are using the best technology available that provides clear benefit and cost reduction to drilling operations is a critical step in completing economical wells and increasing geothermal electricity capacity worldwide.

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