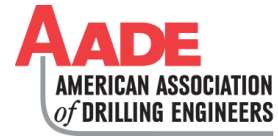


Three-Dimensional Ridge-Shaped Diamond Element Efficiently Removes Rock, Well-Cost



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Abstract

Most traditional polycrystalline diamond compact (PDC) cutting elements have a flat polycrystalline diamond table at the end of cylindrically shaped tungsten carbide body. During drilling, the flat diamond table engages the formation and shears the rock layer by layer. A new ridge-shaped diamond cutting element (RDE) has a similar cylindrical tungsten carbide base; however, the diamond table is shaped like a saddle with an elongated ridge running through the center of the diamond table and normal to the cutter axis. The intended cutting portion, the “ridge,” engages the formation to fracture and shear the rock at the same time. The design intent was to create a unique cutting element that could combine the crush action of a traditional roller cone insert and the shearing action of a conventional PDC cutter. The new cutting elements were tested in the laboratory against standard flat PDC cutters in a rock-cutting evaluation, and later the new elements were applied to PDC bits and run under real drilling conditions.

The laboratory rock-scrape tests indicated that the new cutting element not only enables the cutter to efficiently shear formation in the same way as a conventional PDC cutter, but also delivers a crushing action similar to a roller cone insert. Preliminary results indicated a reduction of roughly 40% in both cutting force and vertical force on the new ridged diamond element cutters (RDE) over a conventional PDC cutter. Similar findings were also observed during the rock-shearing test on a vertical turret lathe (VTL). Subsequent field tests in multiple areas in North America have produced faster rates of penetration (ROP) in most of the cases. The trials indicate that the new cutting element is efficient at removing rock, and a bit equipped with these elements requires less mechanical specific energy (MSE) during drilling than does a bit with a conventional PDC cutter. In addition, the reduced cutting forces reduces bit torque and thus improves the drilling tools' life and the bit directional performance. Field data has proven this technology improves drilling performance in terms of ROP and footage over the current PDC bits fitted with traditional flat PDC cutters.

Traditional PDC Cutter Technologies

It is widely recognized that polycrystalline diamond

compact (PDC) cutters play a decisive role in the performance of downhole drill bits for oil and gas exploration. During the last decade, research and development resources have been focused on delivering new materials to further improve a cutter's wear resistance, impact resistance, and thermal fatigue resistance. Common methods of improving the PDC cutter's performance involve optimizing diamond packing and using high-temperature and high-pressure (HT/HP) sintering for higher diamond volume in the PDC layer. Yet, the understanding of thermal damage to diamond due to frictional heat when drilling hard, abrasive rock led to the widely used process of depleting the catalyst material (Co) from the diamond structure to make it more thermally stable (Schell et al. 2003; Clegg 2006; Hussein et al. 2013). This simple process resulted in a step change in cutter performance in areas demanding high abrasion and thermal resistance for hard rock drilling. Without a doubt, it has further promoted PDC bit use in the last 10 years. Due to the limitation on sintering hardware, the cutter technology seems to have plateaued. To further enhance the PDC cutter wear resistance, a new rotatable cutter technology has been introduced for hard rock drilling (Zhang et al. 2013a, b, c). The new technology allows the PDC cutters to rotate during the drilling process so the life of the cutter could be extended by 3 to 4 times over that of a fixed PDC cutter of the same grade. Consequently, the bits could stay in the hole longer and drill deeper and faster, leading to financial savings for the operators.

Despite the successes the oil services industry has had in PDC cutter technologies, the geometry of most conventional PDC cutters has remained unchanged: a cylindrical shape with a flat synthetic diamond layer attached to a tungsten carbide substrate, which forms the working surface and the cutting edge. Recent development on a conical-shaped polycrystalline diamond element (CDE) has achieved significant success in various applications (Azar et al. 2013; German et al. 2015). One design puts the CDE in the center of a PDC bit along with other strategically placed conventional PDC cutters to create a stress-relieved rock column. This rock column is then continuously crushed by the CDE, which results in faster rates of penetration (ROP) and minimized vibration. Other alternative placements of CDEs include backup positions or leading positions or mixed placement of both on PDC bit blades to combine crushing and

shear actions. The designs have proven to be very successful in super-hard-rock drilling (enhanced bit durability and ROP) and in directional control due to the superior impact resistance of the CDE as well as its unique point-contact geometry. Yet most of the designs require typically high weight on bit (WOB) so the CDEs can engage the rock to achieve crushing action. Thus, there is the need to improve the geometry to make rock removing process even more efficient.

The investigation of ways to improve the conventional PDC cutter focused on three areas. First, a conventional PDC cutter is characterized by a “shear-only” cutting mechanism. The durability of the PDC cutter relies heavily on the wear resistance of its diamond. When drilling abrasive formation, the high degree of frictional heat can generate wear flats (**Fig. 1**) and, in extreme cases, can break down the diamond bond or convert the synthetic diamond back to graphite. Second, a flat working surface can obstruct cuttings from releasing and hamper hydraulic cooling. This could lead to an accumulation and/or packing of drilled formation in front of the cutter causing bit balling and jeopardizing drilling efficiency. Moreover, it can also reduce PDC cutter life due to acceleration in thermal degradation of the diamond layer. Third, in hard/interbedded formations, conventional PDC cutters can suffer frontal impact damage (**Fig. 2**) that could eventually cause bit failure. CDEs could be used to mitigate these issues; however, a higher than normal WOB may not be realistic for extended wells in lateral drilling. It was recognized that a new approach was required to extend the PDC cutter life.



Fig. 1—Wear-damaged PDC cutter.



Fig. 2—Impact-damaged PDC cutter.

New Cutting Mechanism Provided by Ridged Diamond Elements (RDE)

The innovative design of the RDE combines a

standard cylindrical substrate with a modified ridge, or saddle-shape, diamond layer (**Fig. 3**). With this unique geometry, the cutter can efficiently shear formation, similar to a conventional PDC cutter, and also deliver a crushing action similar to that of a roller cone insert. As illustrated in **Fig. 4**, when a flat cutter face engages rock, the shear stress is expected to be distributed along the contact zone marked in red. However, when an RDE contacts the rock, its ridge applies a concentrated load around the tip area such that the stress is much higher than the former case with a conventional PDC cutter. The end result is that the RDE not only shears but also cracks the rock in front of the ridge so the rock removing action is more efficient. The other potential benefit is the easy access of drilling fluid around the ridge to cool the cutter and extend the cutter life. A single-cutter scrape test was set up and conducted to compare the two different cutter geometries (**Fig. 5**). When both types of cutting elements were used to shear rocks with different unconfined strengths, it was found that cutting forces and vertical forces recorded on RDE are about 40% less than those observed from a conventional cutter (**Fig. 6**). Interestingly, the higher the unconfined rock strength, the more reduction in force is recorded, ranking from the softest Wellington Shale to the hardest Utah Lake Limestone.

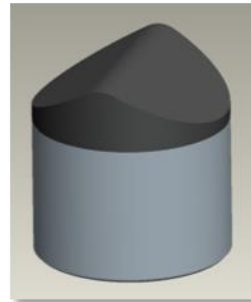


Fig. 3—The RDE (saddle) geometry.

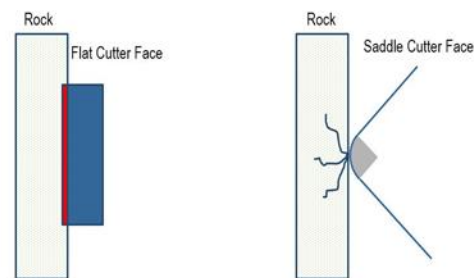


Fig. 4—Cutting mechanism comparison.



Fig. 5 —Single-cutter scrape test on rock.

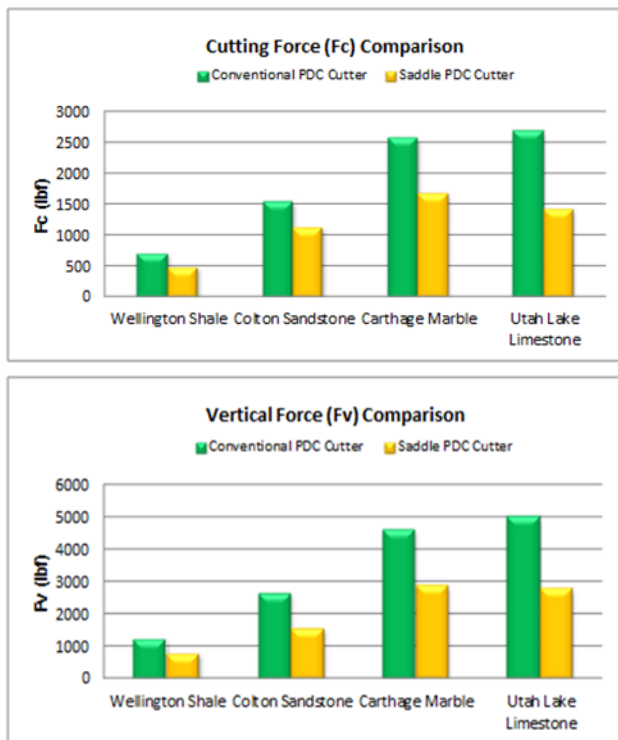


Fig. 6—Cutting and vertical forces comparison of RDE (saddle) and conventional PDC's from the rock mechanics test.

In addition to the rock/cutter mechanic tests, both cutters were also subjected to a rock-shearing test on a VTL to further evaluate the performance differences. In this test, a PDC cutter is fixed on a lathe holder and then it is set at a certain depth of cut (DOC), typically approximately 0.020 in. to 0.050 in., to remove granite from a large granite log (Fig. 7) spinning at certain RPM. Cutting the granite from outer diameter to inner diameter (OD to ID) at a certain DOC concludes one pass on the granite, and the same cutting sequence continues until the cutter dulls when the weight on cutter is over a preset value or a certain predetermined pass number is reached. During the test, the force and temperature on cutter is recorded by a load cell

and a thermal couple. Further, the wear flats are also measured when test finishes. So, the lesser the wear flat area or lesser the vertical force, the better the abrasion resistance of the cutter when two type of cutters have the same pass numbers. As shown in Fig. 8, the RDE lasted an average of 37 passes whereas the conventional PDC cutters lasted 17 passes. In wear flat measurements, after 15 passes, the conventional PDC cutter had a wear flat over 5 mm² whereas the RDE registered a wear flat of only 2.7 mm². Moreover, reduction in temperature on the RDE was observed during the VTL tests. As shown in Fig. 9, the temperature measurement on the diamond table at each pass is continuously recorded. The RDE on average shows about 20% lower value than that measured on a conventional PDC. This further proves the combined cutting mechanisms generating less heat; the shape assists hydraulic cooling, which leads to increased drilling efficiency and longer cutter life. The unique shearing/crushing action could be verified by the cutting size comparison from Fig. 10. The photo on the left shows the cuttings collected from a conventional cutter during the test, and the right photo exhibits the cuttings created from a RDE. The cutting size is clearly larger on the right, which confirms the theory that the new RDE is capable of producing an entirely new “shear plus crush” cutting mechanism and holds vast potential to significantly improve PDC bit performance in many hard rock drilling applications.



Fig. 7—A VTL with a granite log.

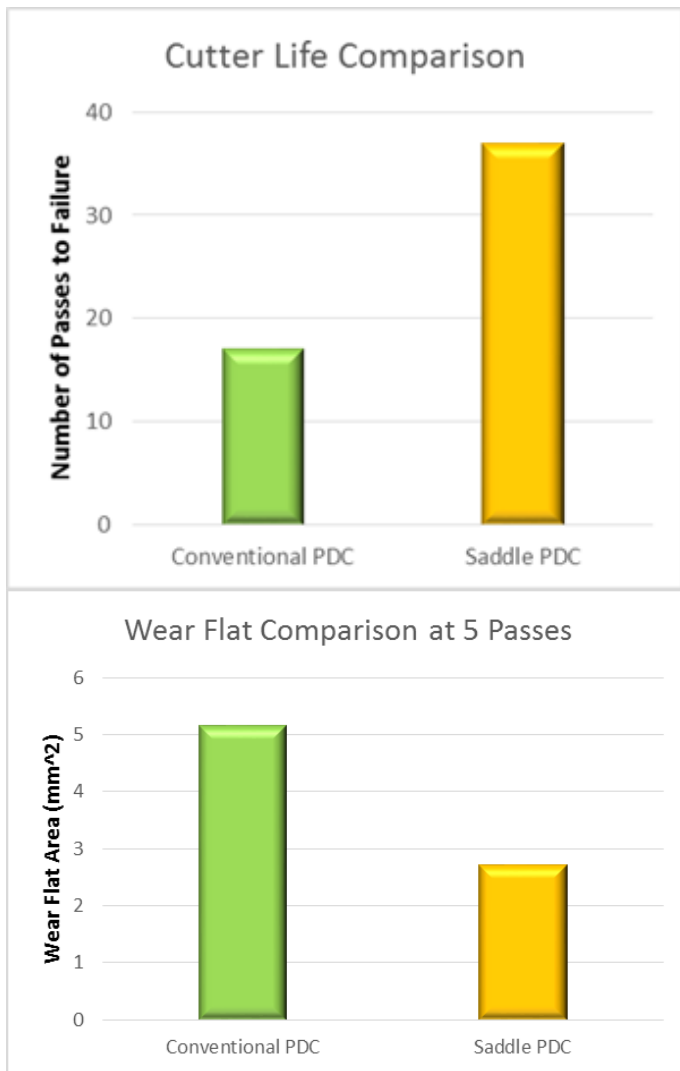


Fig. 8—Cutter life and abrasion resistance comparisons between a conventional PDC cutter and an RDE (saddle).

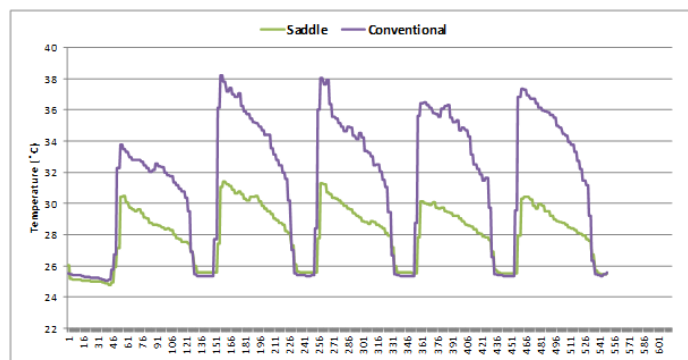


Fig. 9—Temperature measurement comparison between an RDE (saddle) and a conventional PDC.

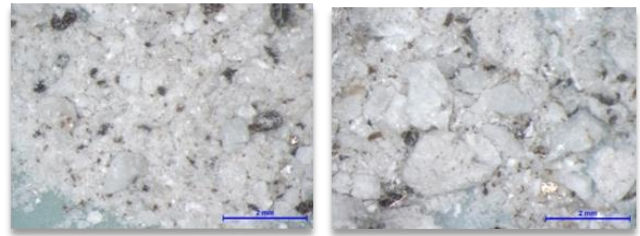


Fig. 10—Cutting sizes comparison between a conventional cutter (left) and an RDE (right).

Case Study – Granite Wash, Oklahoma

The North American Midcontinent Granite Wash play, depicted in **Fig. 11**, comprises a series of tight gas targeted formations expanding from Southwest Oklahoma across the Texas Panhandle. The reservoir is roughly 160 miles long and 30 miles wide, extending from western Washita County, Oklahoma, to Gray and Roberts counties, Texas. In this play, conventional vertical drilling practices have, for the most part, given way to more modern horizontal drilling production. The Granite Wash reservoir comprises shales and sandstones, which can include quartz and feldspar. These pay zones range from 10 to 4,000 ft thick, and the formation play top ranges from 300 to 19,000 ft deep, with the typical target vertical depth between 9,000 and 13,000 ft.

To reach the depths of the pay zones, operators drill through many formations including shale, anhydrite, dolomite, and sandstone. These formations possess unconfined compressive strengths (UCS) on the order of 5,000 psi to 25,000 psi and include stringers with UCS that can exceed 30,000 psi. These interbedded formations, observed in **Fig. 12**, were traditionally and formerly drilled with conventional roller cone technology, and still present a challenge for today’s modern, fixed-cutter PDC bits. For the operators to complete and produce each well economically, each interval must be drilled as efficiently as possible. The specific drilling intervals of the Granite Wash play that consist of many different formation types and the wide-ranging UCS represent a positive testing ground for a more efficient cutting mechanism such as the RDE.

GRANITE WASH MAP

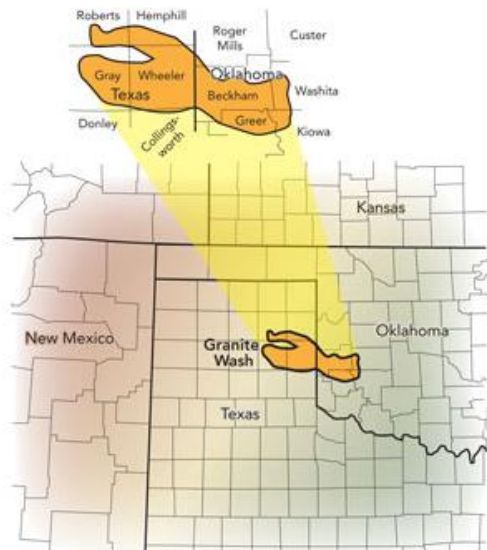


Fig. 11 - Geographical location Granite Wash play.

A typical wellbore plan schematic for a Granite Wash horizontal target is shown on Fig. 13. The target interval for the RDE testing is the 8.75-in. intermediate borehole ranging from 6,100 ft to 10,383 ft measured depth (MD) reaching the interval planned total depth (TD). Criteria for selecting this interval were formation types and rock strengths, the bit design and type (six-blades, 16-mm PDC cutters) traditionally used, offset data and bit run information, and the specific drilling operator and drilling contractor rig.

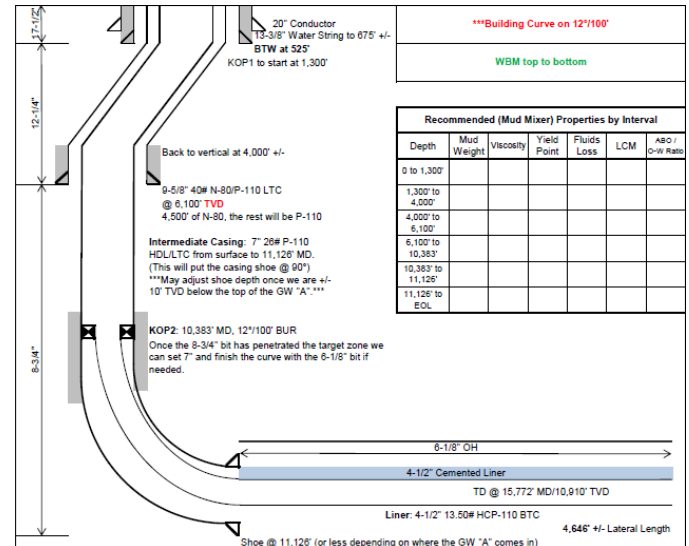


Fig. 13—Typical Granite Wash wellbore schematic.

A test well and an interval in the well were selected based on the criteria described above. The location and interval, which is in Roberts County, Texas, was specifically chosen to limit variables that may adversely affect testing results. These variables include

- bit design and type: 8.75-in six-blade, 16-mm PDC cutters
- drilling contractor and rig
- bottom-hole assembly (BHA) (Fig. 14)
- offset drilling data

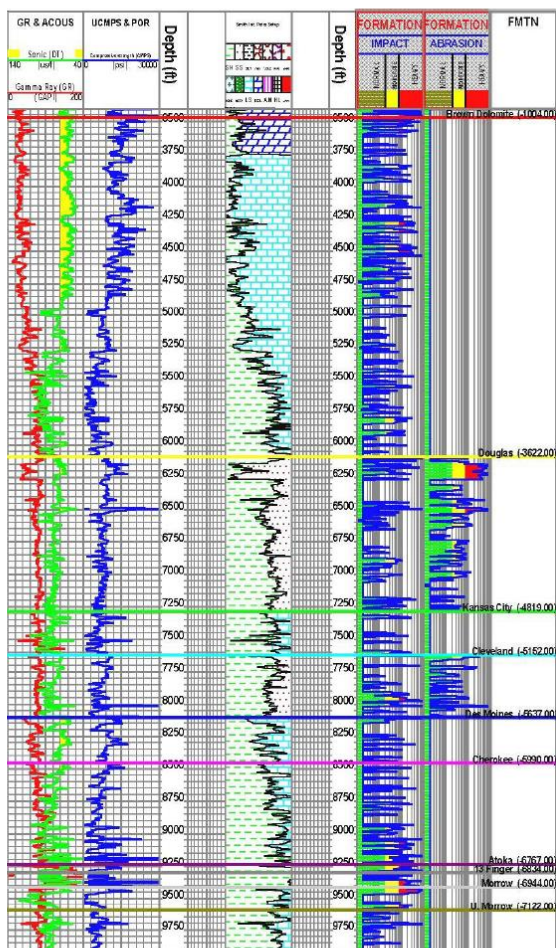


Fig. 12—Granite Wash vertical interval formation properties, including UCS.

Bottom Hole Assembly				
Item	#	OD (in)	ID	Length Ft
BIT	1	8.75		1.00
MOTOR (1.83*)	1	6.75	2.13	25.72
UBHO	1	6.90	3.15	2.67
NMDC	1	6.93	3.32	30.96
FLOW SLEEVE	1	6.75	2.85	2.66
XO (4 1/2 if X 4 1/2 xo	1	6.50	2.85	3.45
6 5 DC'S	6	6.50	2.38	182.37
X/O (4 1/2 xo X 4 1/2 if)	1	6.50	3.00	3.11
5" HWDP	33	5.00	3.00	1015.31
JARS	1	5.00	2.85	32.49
5" HWDP	5	5.00	3.00	
Total				1299.74

Fig. 14—RDE test bit BHA.

An offset well of similar proximity and drilling interval that used the same drill bit design equipped with conventional PDC cutters and the same drilling contractor rig was selected for the analysis. The case study compares total footage and hours drilled in the specific interval and the resulting cost per foot (CPF) (Fig. 15). Values are based on a direct data comparison with uniform drill bit (USD 20,000/bit) and rig costs (USD 2,500/hr). Performance gains observed when utilizing the new geometry RDE are realized by comparing the CPF values. A baseline standard PDC configured offset bit run yielded a CPF of USD 52.13 whereas the drill bit equipped with the RDE delivered a lower CPF of USD 39.79. The increased drilling efficiency resulted in a cost savings of 24% or USD 13,185 compared to the offset drilled with a drill bit equipped with a conventional PDC cutter. Further, the dull comparison in Fig. 16 does show equivalent conditions, which indicates the RDE is as durable as the conventional cutting element.



Fig. 16—RDE-equipped drill bit dull (top) and standard-cutter-equipped drill bit dull (below)

In summary, based on the analysis of the case study that compared the RDE-equipped drill bit performance with that of the standard-cutter-equipped drill bit, the operator realized a performance gain using the PDC bit equipped with the RDE geometry. The increase in rate of penetration (ROP) produces a benefit of cost savings gained by the operator of 24% through the drilling interval. The validity of the efficiency gain was supported by the fact that variations in parameters that could affect the drilling results were minimized; the comparison was made with offset data from a similar geographic location, the same drilling contractor and rig were used, the same interval was drilled, and the BHAs were similar.

Case Study – Williston Basin, North Dakota

In the Williston Basin, operators target several formations to drill horizontal wells. The main formation targeted is the Middle Bakken, which is an argillaceous siltstone, sandstone, and shale with a dolomitic cement. The depth and thickness of the Middle Bakken can vary depending on the geographical location. In the North Dakota counties of Williams, Mountrail, McKenzie, and Dunn, where a majority of the drilling activity takes place, the Middle Bakken formation is approximately 9,000 to 11,000 ft below the surface, and the thickness ranges from 10 to 75 ft. To reach the Middle Bakken, operators will typically drill a conductor hole, then drill a 13.5-in surface hole to 2,000 ft. An 8.75-in intermediate vertical section is then drilled to a depth between 8,500 ft and 10,500 ft TVD. An 8.75-in curve is then drilled followed by a 6-in lateral in the target formation. The length of the lateral portion varies between 5,000 ft to over 15,000 ft, with the majority being around 10,000 ft long.

Currently, the trend is to use two bits to drill the entire 8.75-in vertical section. One challenge facing operators is drilling the lower portion of the 8.75-in intermediate section as quickly as possible. A typical operator will use the first bit to drill from 2,000 ft to the top of the Kibbey Limestone formation, which can have a TVD between 7,500 and 9,000 ft. The operator will then drill the lower portion of the intermediate section with a sharp bit. The main formations that make up the lower portion are the Kibbey Limestone, Charles Salt, Mission Canyon (limestone with some anhydrite), and the Lodgepole Limestone. The compressive strength of the Charles Salt can

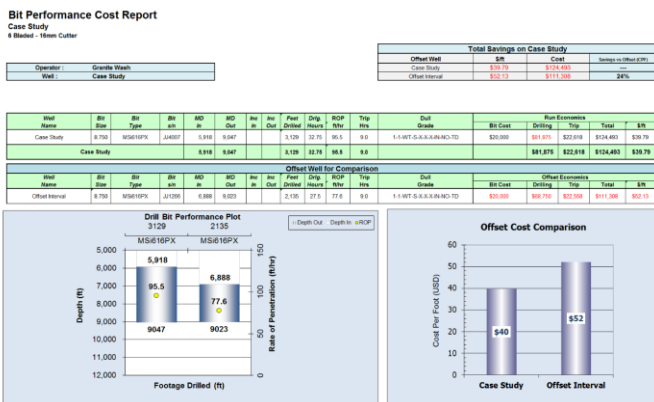


Fig. 15—Bit performance cost report.

range from 12,000 to 24,000 psi, and most of the Limestones are more consistent and between 18,000 to 20,000 psi.

One operator was the first to drill with the new RDE bit in Williston, North Dakota. They targeted the roughly 2,100-ft bottom-hole portion of the 8.75 inch intermediate section on three separate rigs. On each of the rigs very first run with an RDE bit, they outperformed their average PDC bit ROP over the interval by 16%, 34%, and 24% (Fig. 17).

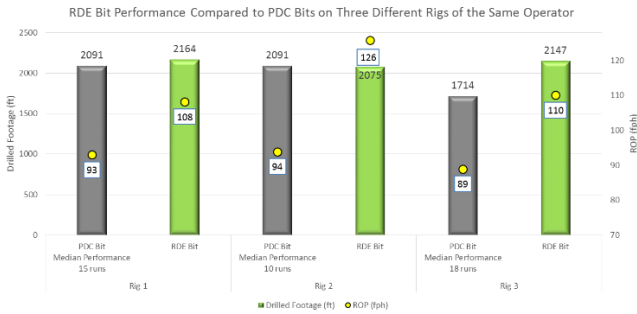


Fig. 17 – Performance comparison of RDE bits versus PDC bits on three different rigs of the same operator

The offset PDC bits ran on these rigs had a typical dull grade of 1-2-CT, but the dull condition of the RDE bits were greatly improved due to the inherent impact and wear resistance. The RDE bits were graded a 0-1-CT, 0-1-SP, and 0-0-NO, meaning one of the bits showed no sign of dulling even after drilling 2,147 ft at 110.1 ft/h.

On average, these three rigs would drill the 2,100-ft interval in 22.9 hours. The average RDE bit took 18.4 hours, saving the operator 4.5 hours per well and reducing the drilling time by 20%. The drilling efficiency and durability of the RDE bit has proven to decrease well cost by reducing the time needed to drill the bottom-hole interval.

When comparing 3 PDC bits and 1 RDE bit on the same rig and on the same 4-well pad, the cutting efficiency of the RDE bit became clear in the formation known as the Lodgepole Limestone. The Lodgepole formation is approximately 500 ft thick and therefore around 25% of the entire bottom-hole footage. Though this interval the operator applied very similar energy (weight on bit and RPM) to the RDE bit and offset PDC bits, the WOB and RPM of all bits were within 7% of each other. The RDE bit produced an increased in ROP by 62% providing real value to the operator (Fig. 18). The higher ROP out for the same energy applied indicated the RDE bit’s ability to remove rock more efficiently.

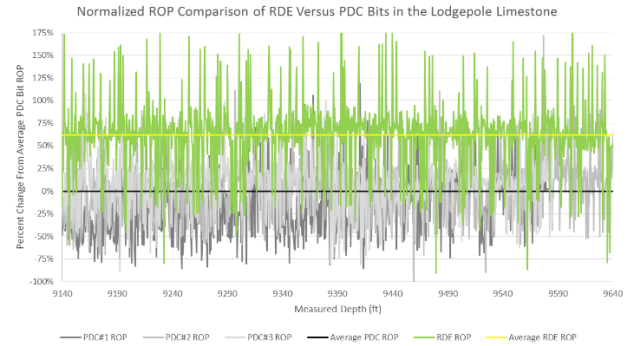


Fig. 18 – Normalized ROP comparison of an RDE bit versus 3 PDC bits on the same pad

A second operator in the Williston Basin reviewed the vertical RDE bit data from the first operator. This second operator was drilling a number of complex wells that included drilling 3-mile, 6-in laterals illustrated in Fig. 19, and decided RDE bits may provide value. After seeing the value RDE bits provided in the 8.75-in vertical section, this second operator decided to apply RDE technology to their 6-in Middle Bakken lateral intervals. In order to drill the lateral at the lowest cost per foot, the operator had to optimize the BHA to be both reliable and fast. Several considerations were made when designing the BHA including torque and drag, motor reliability, MWD reliability, bit durability and trackability.

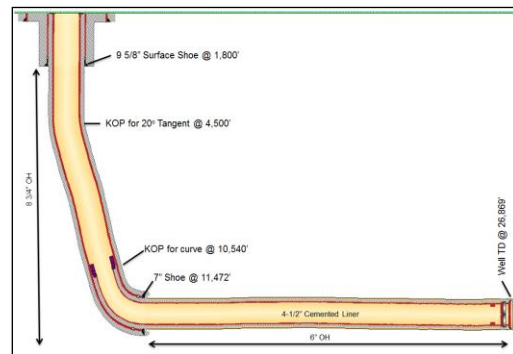


Fig. 19 – well schematic of one of the complex wells on the pad.

The operator had five Middle Bakken laterals to drill that average 15,373 ft in length. The operator decided to test the RDE bit versus conventional PDC bit on three of the lateral, as shown in Fig. 20. The operator decided to drill the first Middle Bakken lateral on the pad with a 6-in PDC bit to get a baseline for the test. The PDC bit run for the first Middle Bakken lateral drilled 9,744 ft before being pulled due to a MWD failure, the PDC bit had dull grade of 2-3. The remaining 5,652 ft of the lateral was fished up with a 2nd lateral BHA.

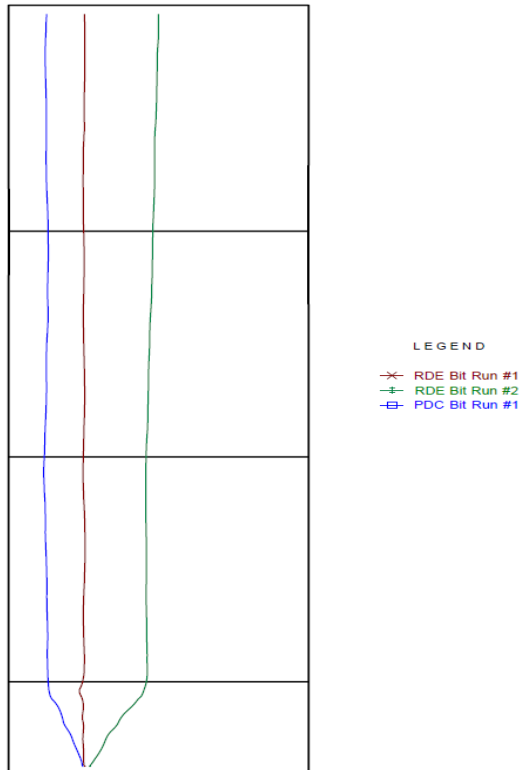


Fig. 20 – plat of the wells that the 6-in RDE bit was tested on.

To best assess the performance advantage that RDE bits could provide, the same BHA components and downhole tools were used on the drill-out runs for the baseline PDC bit and test RDE bit laterals. The only difference in the runs would be the drill bit so any differences in performance could easily be attributed to the bit selected. On the very first run with the 6-in RDE bit, the operator was able to drill the entire 3-mile lateral in one run, setting a world record for the most footage drilled by a single 6-in drill bit. The RDE bit drilled 15,340 ft and graded out a 1-2-WT-S-X-O-CT-TD. On the fourth Middle Bakken lateral, the operator set a new world record for the most footage drilled on a single 6-in drill bit run with the RDE drill bit. The RDE drill bit on the fourth Middle Bakken lateral drilled 15,375 ft in one run, and the dull bit was graded 1-3-SPA-S-X-0-NO-TD (**Fig. 21**).

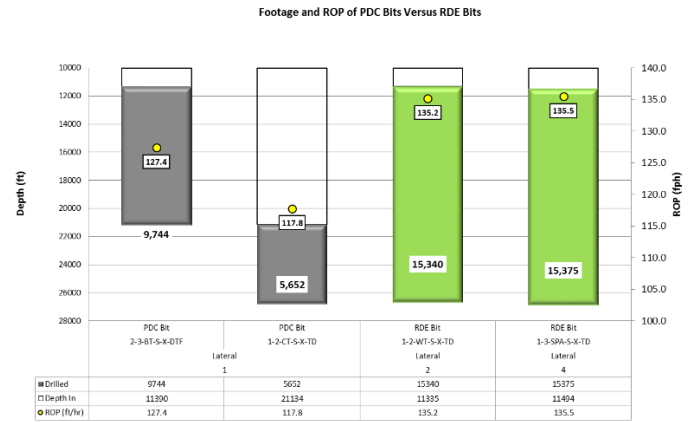


Fig. 21 – Footage and ROP of PDC bits versus RDE bits

Two metrics were identified to evaluate the RDE bit’s performance. The first metric where the RDE bit outperformed the PDC bit was trackability. Trackability of a BHA when drilling laterals in the Williston basin is very significant to operators. Most operators in the Williston basin drill laterals on a bent motor assemble. In order to change direction in the lateral with a bent motor, the driller has to slide the BHA in the direction in which he wants to achieve. Slide ROP can be as much as 90% less than rotating ROP. The operator was able to reduce slide footage by an average of 45% and reduce slide time by an average of 31% (**Fig 22 & Fig. 23**) resulting in a 9% reduction (11 total hours) in overall drilling hours needed to reach the end of the lateral. In addition to the time saved by spending less time at slow sliding ROP, another benefit in reducing slide-time is minimizing the demand and stress on a drilling motor. Sliding operation is much more demanding and detrimental to a motor than rotating. The less time an operator spends sliding the longer the motor is likely to stay operational. The reduction in slide time and footage provided by the RDE bit lengthened the life of the motor making it possible for the operator to drill the world-record lengths in one bit and one motor.

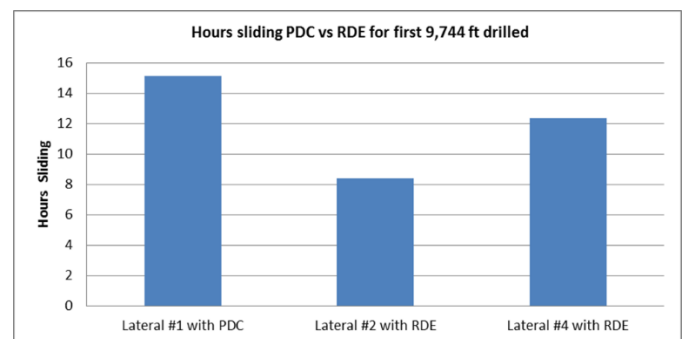


Fig 22 – Shows the reduction in slide time with the RDE compared to the PDC bit

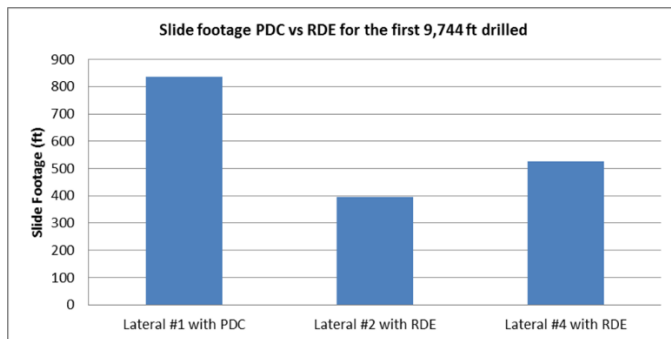


Fig 23 – Shows the reduction in slide footage with the RDE compared to the PDC bit

The second metric where the RDE bit outperformed the PDC bit was in mitigating lateral shock. Shock is characterized as a violent shake or vibration. When violent shaking or vibration occurs in a drill string in a direction perpendicular to the wellbore this is known as ‘lateral shock’. Lateral shock is often the most damaging type of vibration due to the relatively high force magnitudes compared to axial shock (vibration acting parallel to the wellbore) or torsional shock (vibration acting rotationally). A measurement while drilling (MWD) tool is commonly used in a BHA to record and track the shock and vibration seen downhole. The lateral shock data recorded by the MWD tool from the operator’s three lateral wells is shown on **Fig. 24**. The MWD tool sampled data at a rate of 6 times each second. The first PDC in lateral 1 only drilled a little more than 9,500 feet total so only the first 9,500 feet of all three laterals were included in **Fig. 24**. The 95th percentile of the magnitude of the lateral shock is also labeled in **Fig. 24**. The 95th percentile magnitude of lateral shock produced by the PDC bit in lateral 1 was 14.8 Gs while the RDE bits in lateral 2 and 4 were 9.6 and 12.3Gs, respectively. The RDEs average of 11.0 Gs between the two runs showed a 26% reduction in lateral shock magnitude. Reducing the lateral shock on the MWD tool can aid in preventing MWD failure and unplanned trips. The reduction in lateral shock and reduction in stress to the drilling motor from the RDE bit could have prolonged the life of the MWD tool and drilling motor, which in return help the RDE bit set the world record for footage.

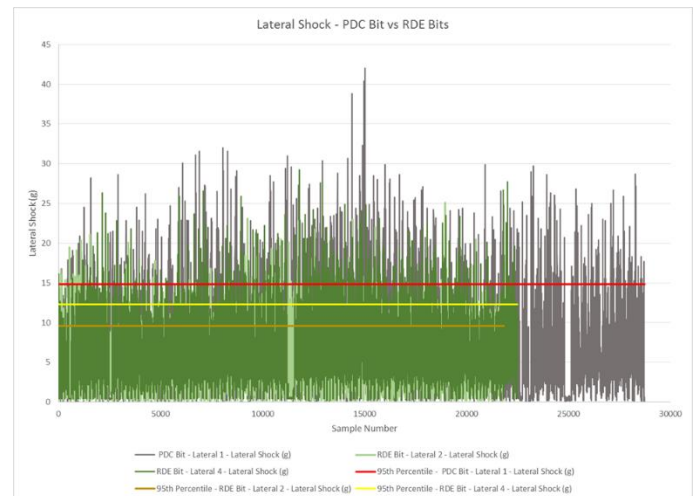


Fig 24 – Lateral shock comparison of the PDC bit and the RDE bits

Conclusion

The initial premise that the RDE would fundamentally alter the cutting mechanism and lift overall performance proved valid. R&D engineers are currently working to take full advantage of the new RDE’s superior resistance to abrasive wear, improved cuttings dispersal, and ability to dissipate frictional heat. An expanded field evaluation is underway worldwide in various applications. RDE bits are proving to provide operators value through world-record-breaking performance.

Acknowledgments

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