Robert Ford, Smith Bits - a Schlumberger company, USA, examines a new PDC design that allows operators to get more from their drill bits.

Since their introduction in the early 1970s, polycrystalline diamond compact (PDC) cutters quickly changed the way drillers constructed wells. Today, PDC cutters are the dominant workhorse cutting element for the drilling industry, accounting for more than 80% of the total footage drilled in oil and gas wells worldwide.

In the past 40 years, changes to PDC drill bits – improved synthetic diamond cutters coupled with new body designs, for example – have vastly improved their performance in high-wear and abrasive formations. Yet despite their dominance on
the global drilling stage, most PDC cutters still contain a design flaw that limits their drilling efficiency. Most of the cutter’s edge is fixed into the bit blade, which limits their contact with the formation. Those cutters that contact and shear the rock during drilling do the majority of the work to create new hole, and thus wear flat quickly.

This reduces cutting efficiency dramatically, forcing the driller to pull the drill string out of hole to replace the bit. Examination at surface confirms that only 10 - 40% of the PDC cutters are typically worn down, and more than 60% of the cutter’s circumferential edge goes unused during the run (Figure 1).

Redesigned to roll

This common challenge prompted Smith Bits to embark on a research and redesign effort to improve the performance of PDC bits, and extend their useful life in the well. The work focused on developing a fully rotatable PDC cutter that would maximise contact with the rock and improve the cutting efficiency of the drill bit. By ensuring that the part of the cutter’s edge making contact with the formation is continually refreshed, each cutter would stay sharper for a longer period of time and the durability of the entire bit would increase. In addition, the rotating action of the bit would improve thermal dissipation, thus preventing concentrated heat build-up that damages synthetic diamond.

Design began with the development of a cutter system composed of a housing that is brazed into the bit blade. A sleeve in the housing encloses and secures the cutter, while allowing it to rotate (Figure 2). The ONYX 360° rolling PDC cutter is oriented in the bit blade such that its contact with the formation and the

Figure 1. In a fixed PDC cutter, only the outside edge of the cutter comes into contact with the rock during drilling. As a result, a significant part of the cutter edge remains unused, leading to more frequent replacement of worn bits. (Image courtesy of Schlumberger.)

Figure 2. The rolling cutter in its integrated housing. (Image courtesy of Schlumberger.)

![Figure 3](image)

The wear fixed cutters incur is concentrated on only a small percentage of the cutter’s entire diamond edge. As a result, after 90 passes on a test formation, premium fixed cutters developed extreme wear flats. Because 100% of the ONYX 360 rolling cutter’s diamond edge engaged the test formation, wear was evenly distributed, resulting in virtually no wear after 300 passes and very little wear after 540 passes.

Figure 3. Visual comparison of the ONYX 360 rolling PDC cutter and fixed PDC cutter on a high strength granite wear test, showing the reduced wear at the cutting edge of the rolling cutter. (Image courtesy of Schlumberger.)
bit’s drilling force allow for free rotation, thus helping improve run life in the well without prematurely pulling out of hole.

With the new design in place, durability tests were conducted in which the new rolling cutter was compared to a premium PDC fixed cutter. Both cutters were mounted on test fixtures to engage a granite test formation with an unconfined compressive strength of 30 000 psi. Maintaining rate of penetration (ROP) during the test required that the vertical force for the fixed cutters be continually increased from 100 lbf to more than 1200 lbf to compensate for wear rate. The rolling cutters required substantially less additional loading force as drilling progressed, indicating improved durability of the cutters during the test interval.

This was confirmed upon visual inspection of the cutters after the test. The wear incurred on the fixed cutters was concentrated on a small percentage of the entire diamond edge, and after 90 passes on the test formation, these edges developed extreme wear flats. But because all of the rolling PDC cutter’s diamond edges engaged the test formation, wear was evenly distributed. Virtually no wear was observed after 300 passes, and very little wear occurred after 540 passes (Figure 3).

Upon successful completion of the first round of laboratory testing, bit engineers then entered the rotating cutter design into the IDEAS* integrated drillbit design platform. This enabled the engineers to study how best to integrate the cutters into the bit’s cutting structure for reliable rotation and optimal drilling performance.

Simulations were performed to predict the degree and precise location of wear expected in the cutting structure in abrasive formations. This work showed that the bit’s shoulder area, between the centre of the cutting structure and the gauge, experienced the most wear, which correlates strongly with field results observed using fixed cutters. The IDEAS drill bit design platform then allowed fixed cutters in the highest wear areas of the PDC bit’s cutting structure to be selectively replaced with rolling PDC cutters. Further simulations showed that by positioning the rolling cutters in place of fixed cutters in the high wear area, cutter life and overall bit durability are optimised.

The optimal rolling cutter placement suggested from the simulation work was then evaluated in a field test in which rolling cutters were fitted to a PDC bit blade, right next to fixed cutters (Figure 4). After drilling an 1800 ft (548.6 m) horizontal section in an abrasive sandstone formation, both cutter types were evaluated. While the fixed cutters showed significant wear and were in poor condition, the neighbouring rolling cutters demonstrated very low and uniform wear. This provided evidence that rotation of the new cutters had taken place, and that using them in the shoulder area of the bit would increase durability.

**Taking to the field**

An operator in the Texas Panhandle’s Granite Wash formation elected to give the new rolling PDC cutter its first field runs to drill 6 1/8 in. lateral gas sections of at least 5000 ft (1524 m) through abrasive reservoir sand. This same formation caused some fixed-cutter-only PDC bits to incur worn, chipped and broken cutters in a relatively short period of time. The damage to the fixed cutter structure reduced ROP to unacceptable levels, forcing the operator to trip out for a new bit after drilling less than 65 ft (20 m) in some instances.

![Image](image_url)

Figure 4. An 6 1/8 in. PDC bit, with rolling cutters. Rolling cutters a, b, c and d show much reduced wear versus the adjacent fixed cutters (unmarked). (Image courtesy of Schlumberger.)
To address the operator’s bit durability challenge, Smith Bits designed a bit with ONYX 360 rolling PDC cutters strategically positioned to withstand the abrasive conditions in this specific reservoir. This began by using the IDEAS drill bit design platform to guide the placement and positioning of the rolling cutters in areas of the bit’s cutting structure with the highest predicted wear. The design factored in several formation-specific parameters such as rock strength and composition to further customise the cutting structure for the operator’s drilling requirements.

A 6 ½ in. MSiR613 PDC bit was developed based on this design work, which was then fitted with seven rolling PDC cutters positioned in the areas of the bit’s cutting structure with the highest predicted wear. The new bit successfully drilled 1562 ft (476 m) of a 5113 ft (1558 m) lateral at an approximate inclination of 90° and an ROP of 25 ft/hr (7.6 m/hr), a significant improvement over fixed-cutter-only bits.

While the average dull condition of the fixed bits used to drill the same formation was graded 6-3, the rolling cutter bits were graded 3-1. The new bits also saved substantial tripping and drilling times, requiring fewer bit runs per section than fixed cutter bits (up to 10 bit runs to TD were common for the conventional bit design).

Overall drilling performance was also vastly improved with the new rolling cutter design, as the new bits increased ROP by 44% and drilled 57% more footage compared to the best drilling performance by a fixed-cutter-only bit in the same lateral well.

Following this successful first field run, the rolling cutter bit has been used to drill several other wells in Texas and Oklahoma. The ideal application for this technology to date has been in high-wear, abrasive formations such as sandstones with moderate to high compressive strength. The bit has been run in formations with compressive strength ranging from 12 000 psi to over 20 000 psi, with similar gains in bit life and drilling efficiency compared to fixed cutter bits.

**Moving abroad**

Successes in North America have allowed Smith Bits, a Schlumberger company to take the ONYX 360 rolling PDC cutter technology to other challenging reservoirs around the world. In Colombia’s Mirador formation, for example, the rolling cutter bit was considered a viable solution for the operator’s challenge of being able to improve bit run length and drilling performance in the 8 ½ in. section. The highly abrasive sandstone formation making up the Mirador has been a real challenge for conventional fixed cutter bits.

Once again, designing the right rolling PDC cutter solution began by working with the operator to analyse their bottomhole assembly (BHA) data, the geology and geomechanics of their reservoir, directional profiles, mud properties and offset dull condition information. Based on the data from the previous offset bit used, which used an 8 ½ in. MSi813 PDC bit with fixed cutters, an MDSiR813 bit with eight rolling PDC cutters was recommended.

The new bit with rolling cutters drilled 324 ft (98.8 m) in 100 hr for an average ROP of 3.2 ft/hr (0.98 m/hr). The PDC bits with fixed cutters, by contrast, drilled an average of 150 ft (45.7 m) at 2.5 ft/hr (0.76 m/hr) in offset wells, but the cutters wore out quickly due to the sandstone reservoir’s highly abrasive conditions and unconfined compressive strength at 25 000 psi. The rolling cutter bit also increased run footage by 116% while eliminating one bit trip, saving the operator more than two days of rig time and US$ 454 200 in rig costs.

Applications for the rolling cutter bit are not limited to onshore wells. An offshore exploration programme in Australia’s Timor Sea was challenged with drilling through a highly abrasive sandstone formation characterised with unconfined compressive strength between 15 000 and 30 000 psi. Previous attempts to drill an 8 ½ in. vertical borehole through this formation with fixed cutter PDC bits resulted in extremely short bit runs and low ROPs. In addition, erratic torque response caused a reduction in BHA performance and system reliability.

The operator required a PDC bit solution to drill the 8 ½ in. hole section in one bit run and with improved ROP. As with other field applications, the company embarked on a forensic analysis of the fixed PDC cutters used in drilling previous offsets. As expected, this analysis identified accelerated wear flats in the shoulder area, allowing engineers to design a rolling PDC cutter bit design (RC813), in which two 13 mm rolling cutters were positioned in the shoulder area on each of the eight-blades.

The custom-designed bit was deployed in two offshore wells. The first well provided a direct comparison between the conventional fixed cutter PDC and the RC813. The standard PDC, which contained ten 16 mm blades, drilled through 295 ft (90m) of the sandstone formation but was pulled due to low ROP and a dull grade of 8 –3-CR-C-X-IN-BT-PR. The rolling cutter-equipped bit was then deployed, and drilled through 413 ft (126 m) at a ROP of 14 ft/hr (4.3 m/hr). This ROP marked a 19% improvement over the average ROP with fixed cutter bits of 11.8 ft/hr (3.6 m/hr). The RC813 was pulled in good condition and dull graded 1-2-CT-S-X-IN-PN-TD.

The experience of drilling the first well allowed for adjustments to drilling parameters and the orientation of the rolling cutters in the bit prior to running in the second well. These adjustments enabled the RC813 to drill the entire interval in the second well, in one run and at an ROP of 30.3 ft/hr (9.26 m/hr). The rolling cutter PDC bit run was 319% faster than a direct offset that required four standard bits to TD the section at an average ROP of 10.1 ft/hr (3.1 m/hr). The RC813 torque response was smooth compared to the erratic torque response of standard fixed cutters in this formation. The increased footage and ROP helped save the operator over US$ 1 million.

With each new field application of the ONYX 360 rolling PDC cutter valuable insight is gained into how the bit performs in different formations. This informs the development of further iterations of the tool to improve its reliability and expand its applicability. For example, while most of the fieldwork to date has been with 13 mm sized cutters, a 16 mm cutter size is now being developed as per operator requests. This should further expand the application of the technology into other fields that share a need for durable bits that efficiently reach TD through even the most abrasive and high-wear rock formations.

**Note**

*Mark of Schlumberger.*