Tough directional TCIs deliver longer runs with higher ROP in Canadian build sections

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CERTAIN FORMATIONS CREATE unique challenges for operators drilling directional applications with roller cone bits. In western Canada, for example, interbedded formations of hard sandstone, siltstone, shale and chert have frustrated operators using conventional tungsten carbide insert (TCI) bits to drill a directional wellbore. In addition to short runs with low ROP because of high cyclic loading failure, damaging hole-wall contact increases gauge and shirttail wear. With WOB preferentially loaded on the roller cone's heel and adjacent heel area, cutting structure breakdown and seal failures are accelerated. The conventional bits' non-cutting structure elements rapid breakdown causes excessive trips. Overall, these unique loads, stresses and increased drilling cost called for a new approach to TCI bit design.

A drill bit manufacturer set out to solve these TCI directional drilling challenges for operators. An R&D team developed a new generation of patented application-specific design enhancements, including innovative cutting structures that improve durability and ROP, enhanced OD and leg protection to ensure bearing integrity and gauge-holding, and stronger materials and processes to withstand the high cyclic loading of directional drilling. These improvements were refined through extensive simulator and field testing.

This step-change in TCI and steel tooth directional technology ensures consistent build rates with higher instantaneous and overall ROP, more footage and compelling durability. Potential roller cone directional challenges have been diminished significantly to reduce trips. One-bit runs, instead of two- or three-bit runs, are possible now in many horizontal builds. Operators are increasing average footage per run by as much as 121% while improving penetration rates compared with the offsets in western Canada. These achievements are reducing overall drilling time by more than 25%, lowering drilling cost.

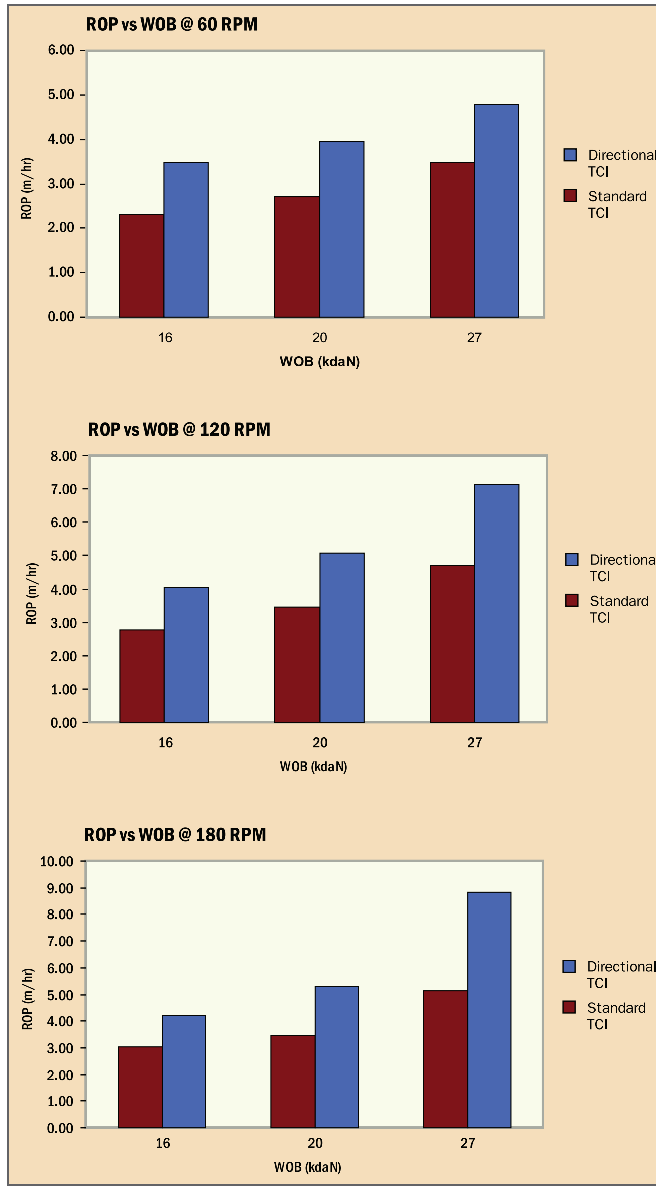

Figure 1: The new TCI directional technology achieves greater ROP, as shown by the drill bit manufacturer's simulator test data using a marble rock sample with 12,000–15,000 psi UCS.

BACKGROUND

The Upper Devonian to Lower Mississippian Bakken formation shales in southeast Saskatchewan, Canada, are receiving increasing attention because of higher crude oil prices and stagnant gas prices in neighboring Alberta. The formation comprises the upper and lower members, which are black, organic-rich shales, and the middle member, which includes sandstone, siltstone and shale. The middle member is the primary target zone in this Canadian application. Low permeability of the middle member makes production from a vertical wellbore ineffective and inefficient. Maximum oil recovery from the Bakken formation is attained by drilling long horizontal legs in the production zone.

Most Bakken target wells in southeast Saskatchewan are single lateral horizontal wells. A vertical 222.3-mm section is drilled to approximately 1,450 m, followed by a 222.3-mm build section drilled to 90° at 6-9°/30 m. The 158.8-mm production interval is drilled to an overall MD of 3,000 m to 3,300 m.

The Bakken formation is overlaid by the Lodgepole (or Souris Valley) formation, which presents a challenge to the drill bit being used to steer the wellbore to 90°. The Lodgepole is thinly bedded throughout with dark grey lime mudstones. Thin, black shale partings have unconfined compressive strength (UCS) of 11,000 psi to 18,000 psi, but can contain as much as 65% chert in the lower region of the bed. This is the major challenge for drill bit durability.

Ideally, one would want a bit that could drill with high ROP in the upper build section, successfully penetrate the Lodgepole chert sections, and still have enough cutting structure to maintain reasonable ROP in the Bakken as the build to 90° is completed. Typically, one roller cone bit would not be durable enough to maintain reasonable ROP throughout the entire section to horizontal. Thus, a bit trip and a second bit would be necessary to finish the section. The 222.3-mm build section challenges created an opportunity for a new directional technology to reduce drilling and trip time and bit cost.

DIRECTIONAL-SPECIFIC TCI RESEARCH

The drill bit manufacturer identified accelerated wear and breakdown of the outermost cutting structure rows as one of the main dull characteristics. The heel and adjacent heel experienced accelerated degradation because of tracking, off-center running and inward loading. Many bits run in severe directional applications also suffered excessive leg wear, which can lead to possible leg breakage and bearing/seal failure.

During research of previous bit performances, the drill bit manufacturer determined bits in the demanding directional applications in the western Canadian regions experience major heel breakage, heel rounding, tracking, off-center running, and excessive leg wear. Typical dull grades were 3-6-BT with bits pulled for slow ROP.

Comparative tests of TCI directional technology versus standard TCI technology were run through a 12,000–15,000 psi UCS marble in a controlled high-pressure downhole simulator (Figure 1). The bottomhole profiles of the two bit types were examined and found to have appreciable differences.

The standard TCI's bottomhole profile had a heavy tracking pattern on the outside of the cutting structure while the directional TCI's bottomhole profile had a smaller tracking pattern on the outside of the outer rows. This reduced the amount of ridge buildup on the profile, allowing the inner rows to continue making impressions in the formation. This information would enable the engineering team to improve drilling efficiency and, ultimately, reduce the chances of cutting structure degradation.

Through extensive testing of various materials, a new process eliminated the press-fit shirttail tungsten carbide inserts and greatly improved the wear life of the OD protection. This enhanced hardfacing protection, which is an extremely wear-resistant material that is applied across most of the OD, is double-thick in more vulnerable areas to dramatically increase durability and wear life. The hardfacing has been added preferentially to the compensator recess area to form advanced updrill protection and also becomes an active cutting element if backreaming is necessary (Figure 2).

These changes enable operators to keep the directional roller cone bit in the hole for the life of the cutting structure, strengthen the leg, and ultimately produce more footage for directional applications.

The heel and adjacent heel degradation issues were addressed with an advanced design. The design involved altering the carbide content on the outer most rows, optimizing the compact shapes, and adjusting the tooth pitch spacing to distribute the work rate effectively across the bit face.

In addition, a dual apex design was included into most directional bits. This design consists of strategically placed nose inserts that cut around the core and provide stability to alleviate the issues of off-center running.

These new TCI design changes improve cutting structure integrity, effectively increase the bit's drilling efficiency and, consequently, increase overall ROP.

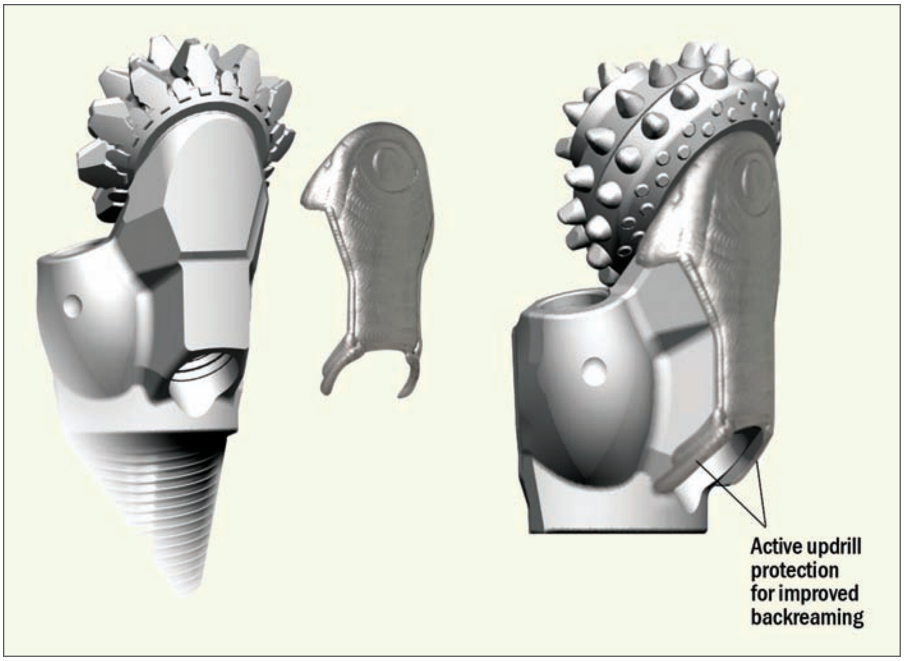

Figure 2: 100% more hardfacing is applied to the shirttail and legs of the drill bit manufacturer's directional steel tooth and TCI bits (left) for enhanced OD wear protection. Patent-pending active updrill protection (right) improves durability in deviated wellbores, especially during backreaming.

THE NEW DIRECTIONAL TCI IN THE FIELD

The well program for the case studies and offsets used a similar well construction. The surface hole was drilled with a 349.2-mm steel tooth roller cone bit from surface to 150–200 m. The section was cased with 244.5-mm casing and cemented. A 222.3-mm polycrystalline diamond compact (PDC) bit on a straight rotary assembly drilled out the casing shoe and drilled the vertical section to approximately 1,300–1,450 m. A motor-steerable directional BHA was tripped in to steer the well to horizontal. The average build length for the offset and case study wells was 333 m.

The offsets and case studies also used similar operating parameters and directional assemblies. BHAs were slick with a 1.83° to 2.12° adjustable kickoff sub on a medium speed (0.09 rev/lpm) positive displacement motor. Flow rate was 1,400 lpm to 1,500 lpm, giving a motor sliding speed of 125 rpm to 135 rpm, plus 30 rpm to 40 rpm on surface while rotating. Weight on bit was 18 kDaN to 26 kDaN. Gel-chemical mud was used with 1,080-1,150 kg/m3 mud weight.

In offset wells, standard IADC 527-547 roller cone bits drilled the build. The average performance for each offset bit in the build was 131 m with an ROP of 6.81m/hr. This equates to 2.5 bits per build section on average.

Drilling a Bakken horizontal well in the Freestone area near Estevan, Saskatchewan, Canada area, a 222.3-mm IADC 527-547 type TCI roller cone bit with directional technology drilled the build section. The bit was tripped in at a depth of 1,333 m. The bit drilled to the intermediate casing point at 1,598 m in 36.5 hr for a total distance of 265 m and an overall ROP of 7.26 m/hr. This represents a 102% increase in footage and a 6.6% increase in ROP versus the offsets. The operator was able to eliminate two bit trips.

In a second Bakken horizontal well in the Freestone area near Estevan, Saskatchewan, Canada area, an operator tripped in a 222.3-mm directional technology roller cone bit at a depth of 1,393 m. The bit drilled to the intermediate casing point at 1,710 m in 46 hours for a total distance of 317 m and an overall ROP of 6.89 m/hr. This was a 141% improvement in footage and a 1.2% improvement in ROP versus offsets. This operator also eliminated two bit trips.

On average, the directional technology roller cone bits increased bit footage by 121% and ROP 3.9% versus offsets. By drilling the entire build section in one run, the operator reduced overall drilling time by 29% while improving safety with reduced tripping. This translated into a $31,480 saving in trip time and bit cost.

DIRECTIONAL ROLLER CONE OPPORTUNITIES

An increasing number of Canadian oil and gas wells are being drilled directionally or horizontally because of:

• Thin reservoir formations that limit production if drilled vertically.

• Restricted surface access — such as environmentally sensitive areas, lakes or rivers, man-made structures, or areas in which the rights' owner will not permit drilling — that requires setting up the drilling rig adjacent to the desired surface area and directing the wellbore laterally to the zone of interest.

• Multi-leg wells that maximize production and reduce drilling cost by branching off the main hole.

• A need to locate and produce zones that were previously undiscovered or bypassed.

• A need to maintain verticality in sharply dipping, folding or faulted formations in which a steerable bottomhole assembly (BHA) is used to direct the borehole path back to vertical.

With these increased opportunities for directional roller cone drilling in Canada and elsewhere, this TCI technology has significantly reduced unreliable bearing performance, excessive OD wear, and high cyclic loading failure. Innovative bit layouts are impeding cutting structure breakdown, and weld-applied OD protection limits leg and shirttail wear. The carbide volume in the critical heel-adjacent heel area has been optimized to distribute the work rate effectively across the bit face. This design approach reduces tracking and eliminates balling for improved cutting structure integrity without sacrificing speed. High-strength legs are 100% stronger than conventional technology to manage the high cyclic loading effects of directional drilling. Patent-pending active updrill protection improves durability in deviated wellbores, especially during backreaming.

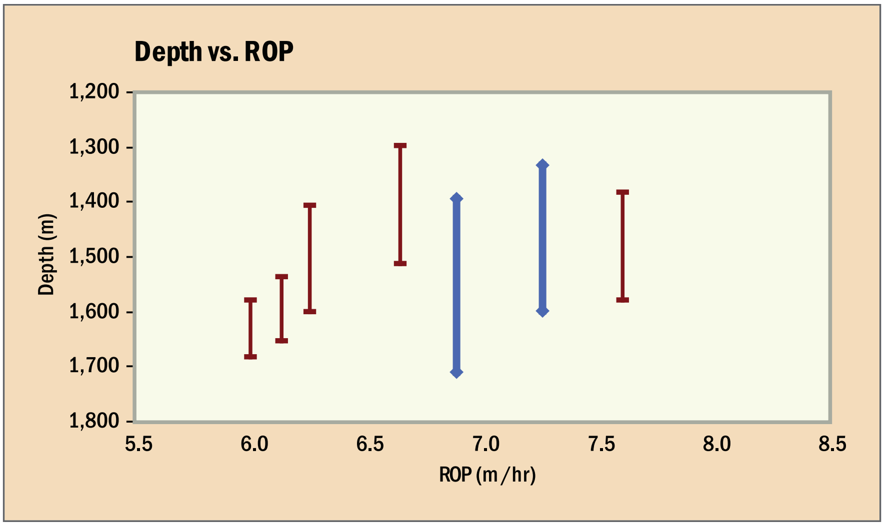

Figure 3: TCI directional technology case study runs (blue) versus offset runs (red) in the Freestone area near Estevan, Saskatchewan.

In southeast Saskatchewan, TCI directional technology has been successful in drilling the build to the Bakken formation at a higher rate of penetration with significantly longer footage versus the offsets (Figure 3). This technology allows operators to complete the entire build section in a single run, reducing overall drilling time and cost per well.