Aggressive Drilling Parameters, PDC-Bit Innovataions Cut Run Times in Abrasive Oklahoma Granite Wash

Peter Langille, SPE, Marathon Oil Corporation; and Jason Hildebrand, SPE, and Kyle Massie, SPE, Hughes Christensen

A combination of new drill-bit technology and new operational practices has enabled operator Marathon Oil to use polycrystalline-diamond-compact (PDC) drill bits, and reduce drilling time by 24%, on wells in a part of the Anadarko basin where abrasive conditions at shallow depths previously have required the use of roller-cone bits.

Much of the Anadarko basin is dominated by PDC-bit drilling. However, in the southwest Canute area of Washita County, Oklahoma, the highly abrasive Granite Wash formation is encountered at depths of 5,000−6,000 ft, compared with its more typical 11,000-ft point of emergence in most of the Anadarko basin.

In the deep Anadarko, of which the southwest Canute area is a part, exploratory wells are drilled either to approximately 13,500 ft to produce the Atoka Wash and Red Fork sands or to approximately 17,500 ft to produce the Morrow sands. The surface string in either type of well is set in or below the Brown dolomite formation (≈3,500−4,500 ft). The lithology below the surface casing consists of a long sequence of sand/shale with interbedded granite wash. This gives way to more-consolidated sand intervals and granite-wash formations, a transition often marked by the showing of the Tonkawa and Prue sands at approximately 9,000 and 11,000 ft, respectively.

In drilling Atoka Wash/Red Fork wells in the southwest Canute area, the operator set a goal of reaching the Prue sands by use of two PDC bits, eliminating the use of three to eight roller-cone bits that previously would have been required. Aggressive drilling parameters typically reserved for roller-cone bits, employing high weight on bit (WOB) and low revolutions per minute (rev/min), were combined with innovative PDC-bit frames, designed to increase the load/cutter ratio, and with new cutter technology to enable the operator to achieve the goal. A depth of 10,700 ft was reached with two PDC bits, and cost savings of approximately USD 200,000 were realized.

Well Plan

For the operator, a typical Atoka Wash/Red Fork well involves a 12.25-in. section drilled into the Brown dolomite and a 7.875-in. section then drilled to total depth (TD). For the 12.25-in. section, casing points differ according to TD. Typically, 9.625-in. casing is set at ≈3,500 ft. The 12.25-in. interval is easily drilled with a single PDC bit.

A 7.875-in. hole is drilled below the 9.625-in. casing and extends to TD. Historically, this interval has been drilled with multiple IADC 5-2-7 or 5-3-7 roller-cone bits. More recently, the use of PDC bits at drillout has become common. However, the ability to make the interval to the Prue sands has proved very elusive.

Bit Technology

The Granite Wash formation has long been difficult to drill. In the southwest Canute area, the interval's overall rock strength is not excessive, but abrasiveness in top-hole sections has generally made multiple runs with roller-cone bits necessary. Compounding this impediment is the rattiness of the formation. Because the wash is a conglomerate of limestone, dolomite, and shale deposited by mountain runoff, it is very hard to anticipate the actual rock composition downhole from one well to the next.

In planning to drill to the Prue with two PDC bits, the operator defined three main objectives for the bits: stability, durability, and performance. Previous dull inspections had shown that a PDC bit had to withstand and minimize damaging vibrations at low-depth-of-cut (DOC) transitions from soft- to hard-rock layers. With the high abrasive wear expected, the PDC bit would have to resist wear flatting, and the layout configuration would have to allow the bit to continue drilling when worn. Because of shale markers between the well-developed sands, the bit would need to penetrate the soft formations at a high rate without balling up.

To minimize the damaging impact of lateral and torsional vibrations, the service company engineered PDC bits with primary and secondary stability. Primary stability represents the bit's tendency to drill smoothly, without inducing vibrations. Secondary stability represents the capability to manage vibration severity when the bit is unstable. A stable bit design allows bit durability and performance to be optimized, without premature wear flatting or cutter failure.

Primary Stability. Primary stability is achieved by incorporating a low-imbalance design and DOC control. The cutting structure is arranged so that the sum of all axial and torsional forces affecting it results in a net imbalance that is small and manageable. This type of design, along with DOC control, minimizes the vibration from bit-to-rock interaction (Al-Suwaidi et al. 2003; Al-Hajji et al. 2003).

To stabilize the bit as it moves through transitional, interbedded lithology, the supplier designed the bit with a DOC-

The material in this article was covered by these authors in paper SPE 105565, presented at the 2007 SPE/IADC Drilling Conference, Amsterdam, 20–22 February.

with zero sand control problems

1,750,000 feet ...and counting

EQUALIZER™ Reservoir-Optimized Completion Systems

- Balances inflow in horizontal wells
- More oil
- Less water
- Fewer wells
- Greater asset NPV
- 1,750,000 feet of EQUALIZER™ run
- 42,000 production units installed in 300 wells

To learn more about how to optimize your production to create greater asset value, visit our website at www.bakeroiltools.com.

BAKER HUGHES

Baker Oil Tools

THE Completion and Intervention Company™

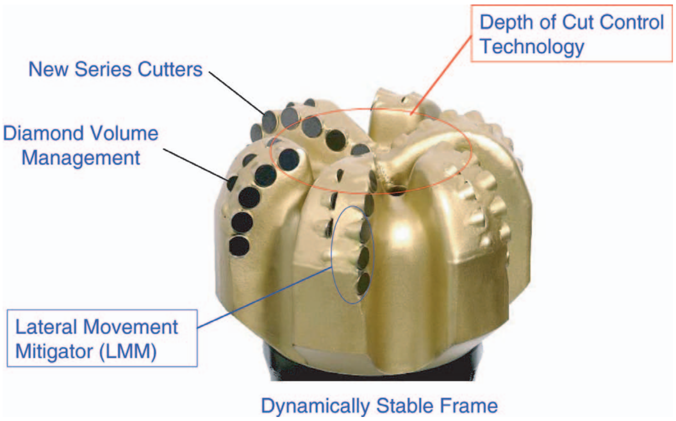

Fig. 1—New PDC technology features.

control feature. Specific cutter loads can increase drastically when the bit encounters hard stringers, damaging the cutters and impairing bit performance. Load balancing by means of DOC control reduces cutter exposure in the cone and nose of the bit, providing uniform loading across the bit face. This innovative design allows the bit to penetrate at high rates in soft formations, while decreasing the likelihood of cutter breakage or chipping caused by hard stringers.

Secondary Stability. The system inevitably will experience some vibration because of bottomhole-assembly (BHA) rotation and PDC-bit shearing action. Secondary stabilization minimizes the effects of drillstring-induced vibrations, especially those at or near the system's resonance frequency. The service company used additional bit technology to reduce the severity of drilling in this unstable mode of vibration. Two of the features designed into this new type of PDC bit **(Fig. 1)** are chordal-drop management and lateral-movement mitigation (LMM).

Chordal drop is the distance between a chord connecting two blades of the bit and a circle around its circumference. Limiting this distance reduces the severity of impact loading on the cutters during bit whirl. LMM technology employs a buildup of material behind and around the bit's gauge and shoulder-cutter area. This limits the instantaneous depth that the gauge and shoulder cutters can penetrate the bottomhole pattern laterally. It also provides a bearing surface on which the bit can rotate, while decreasing lateral cutter loads caused by lateral vibrations.

Cutter Technology. Through a comprehensive research and development program, the service company developed a new series of cutters, with a redesigned interface between the diamond table and the carbide substrate to greatly reduce the residual stresses in the cutter. The new interface removes the highest residual-stress concentrations from that portion of the cutter affected by service-induced wear and stress. Improved residual-stress management allows the cutter to resist spalling, delamination, and impact failures. Newly developed diamond technology has enabled the use of an integrated layered diamond table. The system design includes a wear-resistant top layer to prevent deformation of the cutting geometry and core layers to provide toughness and resistance to impact failure.

Cutting-Structure Design. The service company developed a cutting-structure design that uses a secondary cutting array to extend the performance and durability of PDC bits. The areas where typical PDC bits exhibit the greatest wear have been specially addressed in this design, and diamond-volume management has been employed. The new PDC design insets secondary cutting elements into the blade, producing high cutter density where it is needed most. This extends the reach of PDC-bit applications by improving drilling in a typical dull state.

This technology has allowed the service company to exploit the advantages of a durable, heavy-set cutting structure on an aggressive, lighter-set bit frame. For example, the ability to create a six-bladed bit with the equivalent diamond volume of a nine-bladed bit offers several advantages. Fewer blades require fewer nozzles and provide more junk-slot area to increase hydraulic-cleaning efficiency at the bit. The lower blade count also allows the use of higher blade standoff because of the change in blade thickness and strength.

By maintaining a light-set bit frame and increasing cutter density only where cutter wear is greatest, the newly developed bit is able to match, or exceed, the footage drilled by the older heavy-set bit, without sacrificing rate of penetration (ROP). The matching and correlation of a proprietary PDC-bit wear-modeling program to actual field performance have been incorporated into the new bit design (Dykstra et al. 2001).

Drilling Parameters

In many areas of the Anadarko basin, the basic PDC-bit drilling procedure has been to run light weight and high rev/min to maximize penetration rate. Average operating parameters for a 7.875-in. PDC bit in the recent past have been 12,500-lbm WOB and 146 rev/min, as recorded through bit-record collection. Even with the advancements in PDC technology described earlier, the operator determined that it was necessary to modify the typical PDC-bit drilling procedures in order to achieve the goal that had been set.

Because of the formation rattiness and abrasiveness, the operator had found the use of high rev/min and low WOB to result in shorter runs and increased bit damage. Run parameters were needed that would minimize vibration damage and maximize ROP.

To limit excessive vibration, the operator decided to limit rev/min run on the bit. Laboratory testing in a high-pressure drilling simulator has shown that the component most responsible for ROP change in PDC-bit drilling is WOB (Isbell and Berzas 1999). Testing disclosed that doubling the bit rev/min in 6,000-psi rock, while keeping WOB constant, resulted in a bit ROP increase of 70%. However, doubling WOB, while keeping rev/min constant, resulted in a bit ROP increase of 300%. This testing verified that while either combination of drilling parameters (high WOB/low rev/min or low WOB/high rev/min) could produce similar ROPs, the increase

EXCAPE®
COMPLETION PROCESS

The *Fastest* Path to Production from Multiple Zones

With over 875 zones completed to date, the term *"field-proven"* is an understatement.

To date, more than 875 zones have been completed with the EXCAPE completion process. The EXCAPE completion process has been field-proven to be the fastest path to profits in wells from 2,500 ft. to 13,200 ft. deep with deviations from 1 degree to 93 degrees and temperatures up to 300°F in Oklahoma, Wyoming, Alaska, Texas, Louisiana, Colorado, Mexico and Canada. And, 96% of the frac jobs have been run without screenouts. In one well, 27 modules were isolated, perforated and stimulated in one operation with the EXCAPE process. It's performance like this that earned the EXCAPE completion process *World Oil's* Best Drilling/Completion Solution Award.

To learn how you can escape from the limits of conventional completions and save days of rig time, contact Bruce Bricco at bbricco@bjservices.com or Bill Barton at bill.barton@exprogroup.com.

The EXCAPE Completion Process® was given *World Oil's* Best Drilling/Completion Solution Award

Marathon Oil Company | BJ | EXPRO | GEODynamics Engineered Perforating Solutions

Marathon Oil Company, BJ Services, EXPRO and GEODynamics have teamed together to promote this breakthrough technology.

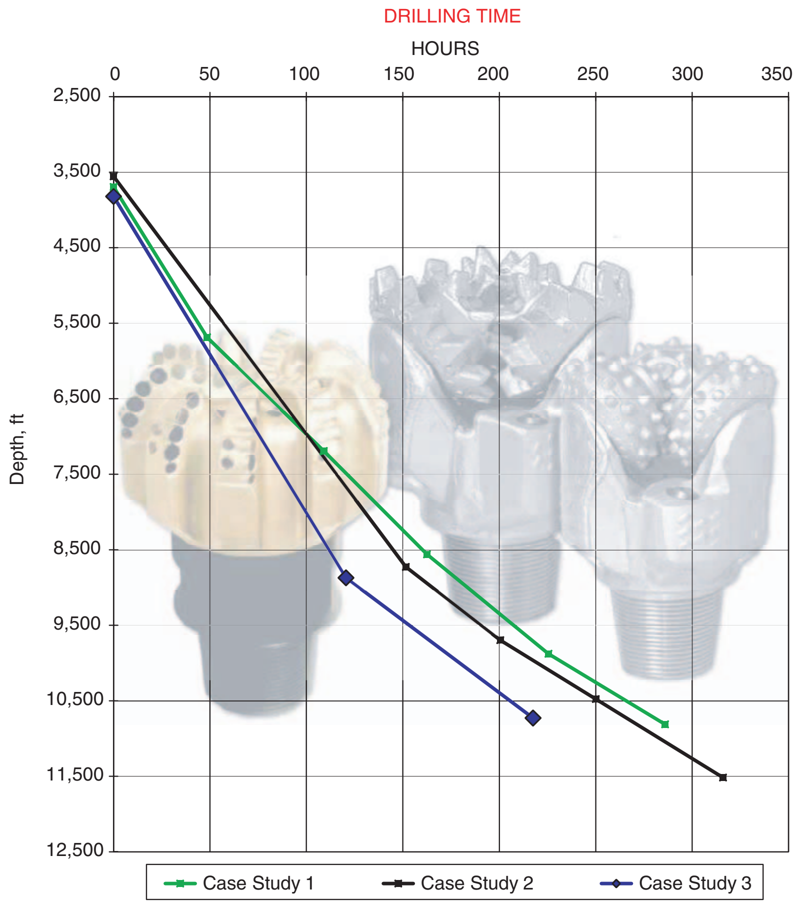

Fig. 2—Rotating hours vs. depth comparison of all case studies.

in WOB required would be comparatively small.

To maximize the efficiency of these run parameters, the operator would need to limit rev/min to 60–65, a range typically reserved for roller-cone bits. Often the rev/min could be slowed further, to the point just above introduction of severe stick/slip. WOB would then be applied to achieve the desired ROP. Conventionally, PDC-bit WOB is limited to 20,000–22,000 lbm on a 7.875-in. bit to limit damage to the cutting elements. Contrarily, recent field experience has indicated that a 7.875-in. PDC bit on a slick assembly can withstand far more WOB and drill successfully, if rev/min are limited accordingly.

Case Studies

Three case studies show the progression of improvement in drilling the Granite Wash interval to the Prue sands. All three studies involve the same drilling rig used over a 6-month span. In Case Study 1, a benchmark well drilled to the Prue used roller-cone bits only. In Case Study 2, a well drilled to the Prue used one PDC bit and two roller-cone bits. In Case Study 3, a well drilled to the Prue used two PDC bits only and reached this objective in significantly less time.

Case Study 1. The BHA of the entire 7.875-in. section consisted of a 7.875-in. roller–cone bit, a motor, a cross over, a teledrift, one 6.25-in. drill collar, one three-point roller reamer, one 6.25-in. drill collar, one three-point roller reamer, two 6.25-in. drill collars, 39 joints of 4.5-in. heavyweight drillpipe, and 4.5-in. drillpipe to surface.

The 9.625-in. casing was set at 3,695 ft. The 7.875-in. interval was drilled with five IADC 5-2-7 roller-cone bits. Similar drilling parameters were used for all five bits (≈200 rev/min and 35- to 40-ksi WOB). The first bit drilled to 5,687 ft (1,992 ft drilled) at 41.07 ft/hr. The bit was pulled for penetration rate with worn teeth and a seal failure. The second bit drilled to 7,192 ft (1,505 ft drilled) at 24.88 ft/hr. The second bit also showed worn teeth as the major dull characteristic, but had all seals effective. The third bit drilled to 8,560 ft (1,368 ft drilled) at 25.57 ft/hr. Again, the dull condition was worn teeth and no seal failures. The fourth bit drilled to 9,876 ft (1,316 ft drilled) at 20.89 ft/hr and showed worn teeth with seals effective. The fifth bit was pulled 200 ft above the Prue sand, at 10,811 ft (935 ft drilled). The bit had an ROP of 15.45 ft/hr and was pulled with worn teeth and multiple seal failures. Cumulatively, the five bits drilled 7,116 ft in 286 hours for an ROP of 24.9 ft/hr.

Case Study 2. For the first bit in the 7.875-in. section, the operator used the bit technology described under the Bit Technology heading, coupled with the run parameters described under Drilling Parameters.

The BHA for the bit run consisted of a 7.875-in. six-bladed PDC bit, a 6.25-in. nonmagnetic drill collar, one 6.25-in. drill collar, one three-point roller reamer, three 6.25-in. drill collars, a drilling jar, 39 joints of 4.5-in. heavyweight drillpipe, and 4.5-in. drillpipe to surface.

The 9.625-in. casing was set at 3,555 ft, and the PDC bit was used to drill out the 7.875-in. section. The PDC bit drilled to 8,726 ft (5,171 ft drilled) at 34.13 ft/hr, an operator record for distance and ROP. The bit was pulled at the top of the Tonkawa sand for penetration rate and showed severe wear and impact damage. To finish the section, the operator ran one IADC 5-2-7 and one IADC 5-3-7 roller-cone bit. The three bits drilled a total of 6,922 ft in 250 hours for an ROP of 27.7 ft/hr, a 12.5% improvement.

Case Study 3. The BHA for both PDC bits included a 7.875-in. PDC bit, a bit sub, a teledrift, two 6.25-in. drill collars, one three-point roller reamer, a drilling jar, 39 joints of 4.5-in. heavyweight drillpipe, and 4.5-in. drillpipe to surface.

To make the interval in two runs, the operator again applied the bit technology and drilling parameters described earlier.

The 9.625-in. casing was set at 3,820 ft. The first PDC bit drilled to a depth of 8,870 ft (5,050 ft drilled) at 41.89 ft/hr, setting a new operator record for distance and ROP to the Tonkawa sand. The bit was pulled for penetration rate and showed extensive damage. Notwithstanding the severe damage to the first bit, the operator—at the recommendation of the bit provider—selected a second PDC bit to attempt completion of the remaining run to the Prue sand.

For the second run, the operator used weights exceeding 30 ksi, while using only 60 rev/min at maximum. By limiting the vibration effects on the bit by means of low rev/min and maximized load on the bit, the operator was able to push the second PDC bit to a 10,728-ft depth (1,858 ft drilled) at 19.15 ft/hr, with minimal dull damage.

Cumulatively, the two PDC bits drilled 6,908 ft in 217.55 hr. for an ROP of 31.75 ft/hr, an additional 13% improvement from Case Study 2 and a total improvement of 24%. This overall drilling improvement resulted in a cost savings to the operator of USD 201,000, calculated on the basis of a USD 1,000/hr rig rate and 1,000-ft/hr trip rate. **Fig. 2** shows the drilling hours-vs.-depth curves for all three wells.

Conclusions

New operating parameters maximized the bit ROP, while minimizing the unwanted vibration effects that caused short runs on previous wells. Innovative bit technology enabled better cleaning efficiency, maximization of diamond volume on a more aggressive frame, and the use of more-wear-resistant cutters. Over a 6-month span, refinement of bit design and operating procedures led to a 24% ROP improvement and cost savings to the operator of more than USD 200,000. The future refinement of these high-WOB/low-rev/min operating parameters holds promise for further improvement in drilling time and bit usage on wells drilled in the southwest Canute area and for expanding PDC-drillable applications generally.

References

Al-Suwaidi, A.S., Soliman, A.A., Klink, Z., Isbell, M., Dykstra, M., and Jones, C. 2003. New PDC Design Process Solves Challenging Directional Application in Abu Dhabi Onshore Fields. Paper SPE 79796 presented at the SPE/IADC Drilling Conference, Amsterdam, 19–21 February.

Al-Hajji, A., Klink, Z., Khan, S., and Isbell, M. 2003. New PDC Technology Solves Challenging Directional Application in Saudi Arabia. Paper SPE 85325 presented at the SPE/IADC Middle East Drilling Conference and Exhibition, Abu Dhabi, UAE, 20–22 October.

Dykstra, M., Neubert, M., Hanson, J.M., and Meiners, M. 2001. Improving Drilling Performance by Applying Advanced Dynamics Models. Paper SPE 67697 presented at the SPE/IADC Drilling Conference, Amsterdam, 27 February–1 March.

Isbell, M.R. and Berzas, S.K. 1999. Re-Engineered Drilling Laboratory is a Premium Tool Advancing Drilling Technology by Simulating Downhole Environments. Paper ASME ETCE99-6653 presented at the ASME Energy Sources Technology Conference and Exhibition, Houston, 1–3 February.

JPT