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Optimized drill pipe connection increases efficiencies in extended-reach applications

A new drill pipe connection, capable of faster makeup and breakout, is reducing NPT in extended-reach drilling and challenging well environments, while remaining economically competitive with other premium connections.

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Fig. 1. Delta-equipped drill pipe at a manufacturing facility in Navasota, Texas.

From 2004 to 2009, drilling companies in the U.S. and international land markets had their first opportunities to experiment with high-torque, premium drill pipe connections. Improvements in design over earlier generations of API rotary-shouldered connections meant that these premium connections could be used in deviated and extended-reach offshore wells to overcome the challenges of using the previous type of connections. Though these premium connections were initially considered suitable only for offshore projects due, to their higher cost, several astute rental tool companies promoted these products onshore, recognizing the opportunity for significant improvement in drilling efficiencies.

For some users, it was an absolute benefit; the slim-line connections meant larger-diameter pipe in smaller holes, enhanced stiffness and improved hydraulics, and helped to create the rise of "factory drilling" onshore. For others, however, the situation was more complicated; though performance was improved, the products cost more, there were more repairs, and there was a steep learning curve for running the premium connections versus API connections. These challenges generated substantial resistance to change. Following the 2008-to-2009 downturn, many operators reviewed plans, and decided that speed and efficiency improvements were worth the learning/cost curve for premium drill pipe and began to transition to land-based premium connections in greater numbers.

ANALYSIS

Over the next seven years, National Oilwell Varco (NOV) had multiple conversations with operators, drilling contractors and rental tool companies about the shortcomings evident in technologies designed for offshore use, when transferred to onshore projects. This is much the same conversation going on for rotary steerable systems onshore. It quickly became apparent that the fast-paced tempo of onshore operations, driven by batch drilling, frequent rig movements; less forgiving rig equipment, and more frequent inspections, was resulting in faster rejection of the pipe. The cost of ownership differential from shorter tong life, uneven wear on the tool joint, extensive tube wear from frequent sliding, more frequent hardbanding, and more kickouts for inspection rejects, resulted in extensive commentary on the necessary alignment of cost and performance. Grant Prideco, NOV's drill pipe and drillstem accessories business unit, set about rectifying the real and perceived shortcomings of the connection, as a result of these conversations.

Over 2.25 MMft of NOV's Delta drill pipe connection are in use around the world, and additional operators are expressing interest in upgrading to the premium connection, Fig. 1. This article examines the reasons that operators are looking to make fundamental changes to their drilling programs in these uncertain times. Specifically, it will detail three U.S.-based customers' drill pipe connection selection criteria, as well as that of one onshore customer and one offshore customer in the Middle East.

CASE HISTORIES

An international oil and gas company that has been operating onshore in the Middle East for many years was looking for upgrades to drill wells more quickly and efficiently. Historical well data from its concession supported the concept of a tapered string of 5½- and 4-in. drill pipe, which enabled drilling at a faster rate than a drillstring comprised of 5- and 3½-in. drill pipe. The industry commonly attributes this to the better hydraulic properties of the larger pipe, but the larger-diameter pipe also improves stiffness, which may help reduce stick-slip to some extent.

Among other criteria, the operator evaluated drill pipe connections and pipe grades. This evaluation process included consideration of previous field experience in the Middle East and successful changes carried out recently in U.S. operations, as well as the objectives of drilling faster, given the constraints driven by casing programs, formation difficulties, pressure regimes, and rig capacities. The operator also expressed a desire to minimize operating issues, including avoiding the use of stabbing guides, which take additional handling, while simultaneously avoiding the stabbing damages that many previous-generation premium connections are prone to, as a result of their shallow taper. As well, prior experience has shown that many premium connections require the box to be gripped at least 2 in. below the sealing shoulder, to avoid elastic deformation during tonging and for the connection to be preloaded correctly when fully made up.

The operator noted that its drilling contractors were using smaller iron roughnecks, which do not have vertical adjustment for the lower tongs and, hence, would require a two-step tonging process to make up high-torque connections. As the operator was looking for quicker, more efficient operations, it chose the fourth-generation Delta connection, which had higher torsional capacity but also addressed running issues, such as shortening the box tong free area to ½-in. during makeup operations, eliminating the need for a stabbing guide and using a steeper taper to facilitate deeper stabbing during tripping and running. In addition to the connection upgrade, the operator selected a new high-strength sour service grade of pipe, HS^3 125, which provided a 19% improvement in tensile capacity over typical 105-ksi sour-service grades. This will allow for greater flexibility in future exploration wells. Drilling operations implementing the complete suite of changes began in the first half of 2019.

Offshore, in the Middle East, the considerations were slightly different. This project had several different design criteria, which were focused on replacing a tapered string (5⅞ × 5-in.) with a single 5½-in. string. The objectives of using the updated connection, which had higher overall torque than the 5⅞-in. string, were to improve annular hydraulics via the smaller-connection OD; to improve the life expectancy of the string by a minimum of 5%, based on recut reductions; and to achieve makeup/breakout times on the rig floor at least 10% faster than previous premium connections while using either the iron roughneck or the floor tongs.

In addition, the ultra-slim connection allowed the operator to use a full-strength overshot, vastly improving fishability in the event it was necessary. Results were positive, with three of the first four wells having improved drilling times. This led to a net reduction in drilling time of approximately 3% over the four wells, which totaled 90,000 ft drilled, Table 1.

The drillers and engineering staff who worked with the string commented positively about connection performance, noting that it was easy to stab-in and faster for makeup/breakout, with most of the connections breaking at or close to MUT (approximately 60 kft-lb). Slip-to-slip time was not recorded correctly, so conclusive data were not gathered to validate the makeup/breakout time as being within 10% of the previous average times. Indirect measures, however, provided enough confidence that the new connections were faster, when compared with previously used products.

After the first well, 10% of the string (90 joints) was sent for a TH Hill DS-1 Category 5 inspection, and after the third well the entire string was sent for DS-1 Category 5 inspection. In total, 1,876 ends (938 joints) were inspected, with

Fig. 2. Fatigue ratio model for 5- × 0.362-in. × S135 with an API NC50 connection with 6⅝-in. OD × 3¼-in. ID in 8.5 section.

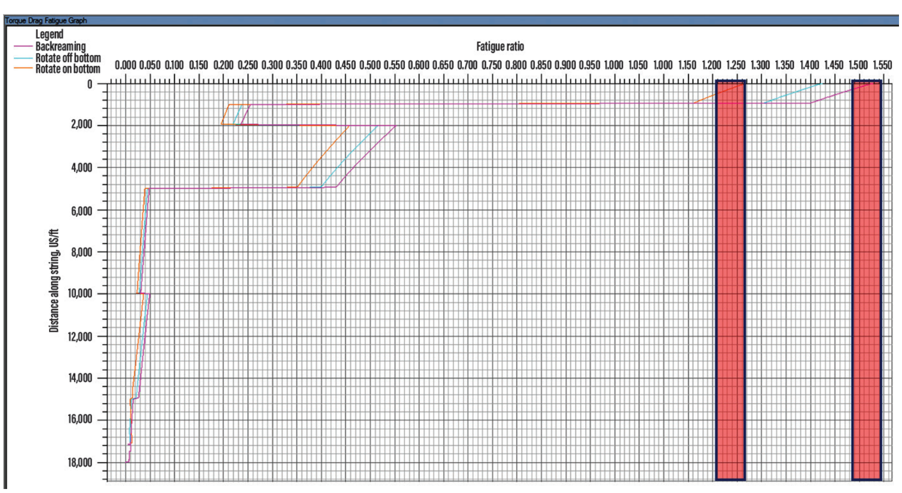


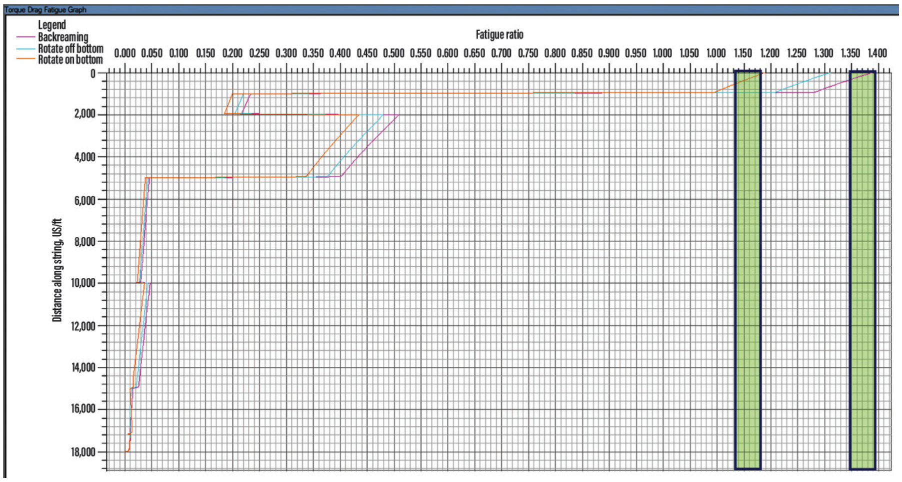
Table 1. Delta performance advantages, including average greater ROP versus the plan.

Rig days	Well TD (ft)	Planned drilling time (hr)	Actual drilling time (hr)	Feet drilled	Planned ROP (ft/hr)	Actual ROP (ft/hr)	Comments
54	20,045	159.5	165	9,990	62.63	60.55	8½-in. section drilled only
65	25,868	577.5	568	25,590	44.31	45.05	
57	25,835	493	487	26,958	54.68	55.36	All pipe sent for inspection
62	27,748	404	366.5	27,748	68.68	75.71	
		1,634.0	1,586.5	90,286	55.25	56.91	

Table 2. Advantages of the new connection, which is rapidly being adopted and continuing to meet customer expectations.

Rig	String	Period	Ends inspected/accepted		Reface		Recut	
Rig 1	Delta	2017 to 2018	1,827	97.40%	26	1.40%	23	1.20%
Rig 1	Previous tapered string	2012 to 2018	5,375	94.80%	62	1.10%	233	4.10%
Eight-rig average	Previous tapered string	2012 to 2018	66,988	92.60%	526	1.40%	161	6.00%

Fig. 3. Fatigue ratio model for 5½- × 0.362-in. × S135 with Delta connection 6⅝-in. OD × 4-in. ID in 8.5 section.



the following results:

- 1,827 ends (97.4%) were accepted
- 26 ends (1.4%) were rejected to reface, due to seal corrosion and/or seal damage
- 23 ends (1.2%) were rejected to recut, 18 due to seal/thread damage or thread corrosion and 5 because of thread galling.

Table 2 summarizes the results from the rig that ran the new connection for three wells versus the same rig using the tapered string for a six-year period. The average recut rates for the new connections were well below the six-year running average at 1.2% vs. 6%. Though this extremely low average was accomplished on relatively new pipe and may increase over time, the numbers seen on a much larger sample base in the U.S. have confirmed the low repair rate.

When discussing U.S. land projects, however, it has become clear that different considerations drive decision-making for operators in West Texas. There are two predominant well profiles in this area: a standard profile with an 8½- or 8¾-in. bottomhole section, and a slim-hole profile with a 6½- or 6¾-in. bottomhole section. In both cases, operators are generally looking at using pipe with the connection to allow for larger-sized pipe in the same hole sections. For the 8½- or 8¾-in. bottomhole section, it is standard to run 5-in. drill pipe with an API NC50 connection, Fig. 2.

This connection has dimensions of 6⅝-in. OD and either a 2¾- or 3¼-in. ID. The connection with the same OD (6⅝ in.) is capable of being used on 5½-in. drill pipe, and the standard connection ID is 4-in, Fig. 3. The operators that are looking at using this configuration of 5½-in. drill pipe, with a Delta 544 connection with 6⅝-in. OD and 4-in. ID, are attracted to specific benefits.

In one case, an operator using the standard 5-in. drill pipe saw a situation where the standpipe pressure had reached its maximum. The operator had to reduce the flowrate and subsequently saw a reduced ROP. On another well on the same pad, the operator utilized a 5½-in. string with the 6⅝-in. OD and 4-in. ID connections. On that well, the operator was able to run with the same flowrate for the entire section and ended up with a faster ROP compared to that of the 5-in. pipe, thereby reducing the time to drill the well. For the slim-hole profile, some operators have been using 4-in. drill pipe in a 6⅛-in. hole section. However, more attention is now being focused on a 6½- or 6¾-in. bottomhole section with a 4½-in. string, using 5¼-in. OD × 3-in. ID Delta 425.

The larger pipe size in the hole section is stiffer, allowing for a straight hole to be drilled in the laterals and to stay in the desired production zone. The larger pipe and larger connection ID also allow for higher flowrates and hydraulic horsepower. The slim 5¼-in. tool joint OD is more beneficial, compared to other slim-line connections, as there are certain formations that are more sensitive to ECD issues. The smaller OD allows for lower ECDs.

A third benefit is the time savings observed by an operator who use the 4½-in. pipe to drill the well, top to bottom. The operator's analysis showed that the time/cost-savings realized from not having to trip out the larger size of pipe for the top-hole sections, and then trip in the smaller size of pipe for the curve and lateral, outweighs the slower drilling required to run in the top hole with the smaller pipe.

Essentially, drilling the entire well is more efficient for this operator with one size of pipe. In addition to these time/cost-savings using a single string, the operator also benefits from a safety perspective, as they are not tripping, laying down, and picking up pipe as often.

VALUE ADDED

The new connection incorporates the many lessons that Grant Prideco learned over the years, together with feedback from end-users, to provide a far more user-friendly design. In addition, the connection is the response to an industry that is demanding performance in extended-reach laterals and challenging well environments while remaining economically feasible.

Throughout extensive connection design validation and testing, performance results have consistently demonstrated that the connection is approximately twice as fast during make-up and break-out as earlier, premium high-torque threads. Furthermore, field testing and project implementation have confirmed the benefits—particularly increases in available torque—and the significant reductions in the cost of pipe maintenance and ownership when using the new connection.

Technology integration with radio frequency identification tags, which provide a means of tracking assets and keeping them traceable to their OEM certificates, is also possible with the connection. WO

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