Challenging ultra-deepwater frontiers beckon for well construction, completion technology

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WHEN THE JACK-2 well test broke production records in 2006, it didn’t just open a valve to drain oil from the Lower Tertiary play: It opened the floodgates for other operators to venture into the ultra-deepwater regions of the Gulf of Mexico.

In water depths of 5,000 ft to 10,000 ft and with target formations at 10,000 ft to 30,000 ft below the mudline, Lower Tertiary developments are an enticing new frontier for both operators and service companies. However, these high-value wells need new technologies.

Even in less challenging deepwater wells, high bottomhole pressures and temperatures and long pay intervals have sparked development of reliable well construction and completion technologies, with much more under way. Downhole systems that were typically rated to 10,000-psi differential pressures a few years ago are now available to 12,500 psi, with 15,000-psi systems on the test bench — and operators already asking for 20,000 psi.

Operators and service companies are also working to surmount economic and logistical challenges involved with these extreme projects. Rig costs are steep for these ultra-deepwater projects, so reliable technologies that save rig time are a high priority. In addition, technologies that minimize fluid, proppant and chemical volumes simplify the logistics related to delivering materials some 175 miles offshore. Finally, workovers on these subsea developments are prohibitively expensive, so technologies that prevent downhole problems (scale, corrosion, asphaltenes, etc.) should be included in an engineered completion design.

HPHT SOLUTIONS

As a gauge of the pressure situation in ultra-deep wells, recall that the Blackbeard West #1 well was temporarily abandoned in 2006 at 30,067 ft because of unexpectedly high pressures. Lower Tertiary wells are expected to see initial bottomhole pressures of some 20,000 psi and temperatures as high as 400°F.

Individually, high pressure and temperature are minor concerns for oilfield equipment, and specialized tools are available for one condition or the other. But combining both creates a design nightmare. In addition to affecting material strength — which affects pressure rating — high temperatures increase corrosion effects and increase the chance for stress cracking.

Even with high-strength metals and elastomers, oilfield equipment designed for use in lower pressure and temperature conditions need redesign.

The new CompSet II HP Extreme packer, for example, is functionally the same as prior CompSet packer technologies, but it was redesigned to enable high-pressure cycling to 12,500-psi working pressure at 350°F. A 15,000-psi version is in the testing phase.

The Extreme packer technology is used for gravel packing, high-rate water packing, frac packing and stimulation.

Packers and completion systems for even more extreme conditions are in the research phase, with operators looking ahead to developments that may see pressures up to 30,000 psi and temperatures above 400°F.

Cementing technology, as well, is developing to meet these extreme deepwater requirements. In 2004, for example, a customer asked BJ to begin developing technology to cement a well with anticipated bottomhole temperature above 580°F and pressure above 35,000 psi. The result was XtremeSet cement, which was used successfully in the highest-pressure well drilled to date in the Gulf of Mexico. State-of-the-art, automated cement pumping equipment such as BJ Seahawk cement units also help to ensure a quality cement job that will provide isolation for the life of the well.

LONG PAY ZONES

In the Lower Tertiary, particularly, the problem of long pay zones becomes a critical issue. Whereas typical deepwater GOM wells comprise 80- to 100-ft zones separated by distinct barriers, the Lower Tertiary is considered to be more of a continuous reservoir with 300- to 1,000-ft pay intervals. Issues with completing such long intervals include:

• Safety. Perforating one long interval requires running hundreds of feet of guns.
• Reliability. If used, screen systems must be able to reliably cover several hundred feet of wellbore over a predictable lifetime. (Workover is not an economical option.) For frac-pack completions, the completion tools must be able
to withstand erosion from some millions of pounds of high-strength proppant.

- Logistics. Rigs and stimulation vessels have a limited amount of payload for fluids and proppant.
- Economics. Rig time is expensive, encouraging technologies that minimize completion and stimulation time.

Operators will likely avoid many of these issues by completing and stimulating these long pay zones as several smaller zones. Multi-zone stimulation is traditionally done in a “stack-pack” method, by perforating, then treating the bottom zone, running bridge plugs into the hole for isolation, and repeating for successive zones up-hole. At the end of the process, the bridge plugs are drilled out.

This is a time-consuming process, necessitating many trips into the well, and therefore much nonproductive time (NPT) and expense. With the depth of the water in the Lower Tertiary and the additional depth of the well itself, tripping time becomes a significant cost.

As an alternative, some operators are turning to the ComPlete MST (multi-zone, single trip) system, which facilitates single-trip gravel- or frac-packed completions across multiple production intervals. To date, as many as six zones have been isolated in one trip, with an eight-zone completion pending.

The result is an effective reduction in completion cycle time and cost by at least 20% and, in some cases, more than 50%, compared with other standard multi-zone completion technologies that require multiple trips. Eliminating one-third of a typical 12-day completion schedule on a multi-zone deepwater well can save the operator $2 million on the total operation, support spread and rig costs.

In the first Gulf of Mexico application in July 2007, perforation guns were run below the MST tool in an effort to further decrease NPT. The operation was successful but required two runs: After perforating, well conditions dictated that the bottomhole assembly be retrieved from the well and a deburring run be made across the perforated intervals. The MST system was redressed and the well successfully completed. After the system was installed, it performed as anticipated: One zone was frac packed with 21,000 lbs and one with 25,000 lbs of gravel as planned. Well performance also met operator expectations.

One operator planning a Lower Tertiary project estimates that each five- to six-zone well in the project would require 100 days to drill and 100 days to complete using traditional technology. Completing the wells using the ComPlete MST system will save the operator about three weeks of rig time — more than $10 million at current deepwater rig day rates — per well.

**FLUID PUMPING ISSUES**

Completion and stimulation fluids must also be carefully designed for these wells, ensuring compatibility with completion tools, tubulars, etc, and considering rig pump pressure limitations. Pumping large volumes of fluid is NPT that most operators would like to minimize.

Weighted fluids provide a solution. For example, in a recent deepwater Gulf of Mexico completion, the operator used 15.4-ppg synthetic oil-base mud (SOBM) to drill a sidetrack to 16,700 ft. After displacement to 15.2-ppg ZnBr2 completion fluid, the well was to be completed with a frac pack.

In a conventional indirect displacement, mud is displaced to seawater and then to the desired completion fluid or in traditional direct displacements, cleaning spacers are built in water and the completion brine follows the cleaning spacers.

In both cases, however, the hydrostatic pressure difference would require extremely high pump pressures to achieve annular velocity required to achieve good cleaning efficiency. (And a clean well is critical to ensuring the completion tools function as designed when run into the well!) However, rig pump limitations dropped the possible rate significantly, adding some 30 hours of displacement time to the job, not counting any additional time that might be required for cleanup due to the reduced efficiency.

Instead, BJ completion engineers proposed a weighted displacement procedure designed to directly displace mud to brine with premixed cleaning spacers, and to clean the wellbore without time-consuming filtration cycles. These displacements minimize waste disposal and reduce rig time and, therefore, rig costs.

The components of the displacement included a weighted displacement spacer system. From the weighted barrier spacer and brine-based cleaning spacers to the high-viscosity sweep, all aspects of the displacement cleaning system were designed to help reduce hydrostatic differential pressures to displace the heavy mud and to effectively clean the wellbore. This displacement system eliminates the need for high-pressure pumping equipment, additional pumps, tie-in to the workstring (creating the loss of rotation without specialized equipment), and it minimizes the rig time spent displacing. This weighted direct displacement removed the wellbore mud, drilling solids and other debris, and restored the tubulars to a clean, water-wet state all while utilizing the most time-efficient displacement method.

To achieve high-efficiency cleaning, the displacement plan called for use of brushes, scrapers and a circulating sub just above the smallest liner.

After the displacement was pumped and the completion fluid was in place, it
was circulated for 1.0 hole cycle before reaching a final turbidity of 15 NTU. Total pump time was 8 hours, with estimated 15 hours of nonproductive time (NPT) savings valued at ~$200,000. Similar time and pump horsepower savings are possible during stimulation by employing weighted fracturing fluids, such as our BrineStar fluid system.

FLOW ASSURANCE ISSUES
Compatibility and flow assurance testing is critical for all fluids, not just those being pumped downhole. Issues with pressure crystallization and hydrate formation increase with deeper water and the resulting larger window of very cold water temperatures.

In some cases, flow assurance may require use of specialized packer fluids, such as the InsuGel family of fluids. Because of the extremely high cost of workovers and the potential lack of availability of rigs in these ultra-deepwater wells, most Lower Tertiary developments will include additional flow assurance measures, such as chemical injection ports for corrosion, scale and other inhibitors depending on reservoir conditions. Traditional chemical injection ports provide one level of protection, but newer technology economically carries inhibitor chemicals closer to the source of the problem.

For example, a large offshore operator recently had a subsea completion fail due to asphaltene plugging, despite routinely bullheading inhibitors from the chemical injection port through the tubing and gravel pack assembly. It was believed that asphaltene buildup was occurring below the production packer, an area which conventional methods cannot treat. While planning a sidetrack, the operator wanted to include a means of avoiding future failures.

In November, BJ installed a new InjectSafe chemical injection system with capillary hanger in the sidetracked well to provide a clean path for the inhibitor chemicals directly to the perforations. An ongoing field study will monitor the effect of moving the point of inhibition from the tubulars to the perforations.

Because the Lower Tertiary play is expected to be very well-consolidated rock, experts expect hydraulic fracturing to be the standard stimulation technology. This opens another opportunity for flow assurance: StimPlus services, which combine stimulation with long-lasting granular scale or paraffin inhibitors. Because the inhibitor is placed with the proppant during the frac, it reaches deep into the reservoir the prevent deposition problems before they affect production. To date, 12 deepwater zones have been treated, with 300 more applications in onshore wells. Well sample residual testing and lack of scale deposition in wells incorporating ScaleSorb 3, a solid scale inhibitor, have indicated successful inhibition of nearly three years and counting. Delaying and/or avoiding intervention reduces operation expenses and improves project economics, necessary in any project, especially in deepwater.

With the world’s continued dependence on hydrocarbon-based energy sources to drive the global economy, pushing into deeper, harsher downhole and surface environments will require these as well as other innovative technologies. Our new state-of-the-art Technology Center in Tomball, Texas, and the expanding Completion Tool Test Technology Center in Houston are evidence of BJ Services’ commitment to investing in step-change technologies.