International E&P report:
Region-by-region review & forecast

Innovative jackup develops Caspian field

First DP FPU for GoM
Providing answers for un-testable wells

Combination tool can give results

Well testing has been a critical step in well evaluation since the 1920s. It has always been the first real measurement of reservoir volumetrics and potential performance.

Described as a temporary completion, well testing gives the industry a chance to flow a well under controlled conditions, allowing it to clean up and stabilize. Total flow rate, as well as the holdup of various phases present, can be measured and representative samples can be taken under PVT conditions for laboratory analysis. Pressure transients can be obtained whose character gives clues about reservoir boundary conditions remote from the well being tested. Reservoir volumes can be calculated along with formation average permeability and near-wellbore formation damage, or “skin.”

Test data
Most subsequent completion decisions are based on information obtained during the well testing phase. The critical inflow performance relationship (IPR) curve is derived from test data, and is the foundation for decisions involving perforating, formation treatment and the sizing of completion hardware and tubulars. Therefore, operators expect well test results to be accurate and of highest quality, because production decisions made from these results can have implications for the life of the well or reservoir.

Although well test data are of high value, operators are constantly evaluating cost versus value. To this end, operators around the world have been working with their service partners to perfect well testing operations and make them as efficient as possible. Traditionally, rig spread costs consume the highest percentage of the well construction budget. Accordingly, the most obvious solution to reducing well test costs is to combine as many operations as possible, or practical, in a single trip.

Testing improvements
The earliest step to improve testing quality and efficiency was the implementation of downhole test tools. With downhole test valves, gauges, and sample chambers, wellbore storage effects could be eliminated or greatly reduced, and measurement quality was enhanced. Without wellbore storage, quality pressure data could be obtained in a fraction of the time required using surface testing. At the same time, accurate quartz gauges made significant improvement in test data accuracy.

The next step taken was to combine perforating and testing. Using a TCP work string brought several advantages. Primary among these was the ability to shoot the well underbalanced to take advantage of instant cleanup of the perforation tunnels of any debris, as well as to prevent an influx of completion fluid into the formation creating near-wellbore formation damage.

When combined with DST, the well could be perforated, cleaned up and immediately tested in one trip. Clean up in this case includes flowing the well long enough to clear it of any residual drilling fluid or filtrate so a representative sample of produced formation fluid could be obtained. The TCP/DST combination made the operation safer, because the well was under control at all times and the perforation cleanup test sequence was performed seamlessly.

Additional challenges
Many wells do not flow naturally to the surface, and despite underbalanced perforating techniques, it may not be possible to get sufficient natural flow to achieve the dynamic flow regime required for a valid well test. Some reservoirs contain lots of crude oil, but lack the pressure drive to flow naturally. Others contain heavy oil (defined as crude oil between 22.3° API and 10.0° API), where viscosity impedes flow to the wellbore. Approximately 15% of the world’s 13 trillion bbl of oil reserves consists of heavy oil, mostly in Venezuela and Russia, but also significantly in half a dozen other countries. In this context, heavy oil is not the bitumen found mainly in western Canada and Russia of 10° API gravity or less.
A comparison of test times for the three wells in the order they were run (from left to right) shows dramatic improvement in efficiency when the triple combo test string was run.

To test all wells efficiently, not just those that flow naturally to surface, Schlumberger combined a tubing-conveyed perforating (TCP) and a drillstem testing (DST) work string with an electrical submersible pump (ESP) to supply the energy to produce from pressure-depleted or heavy oil wells.

**ESP addition**

By combining a TCP and DST work string with an electrical submersible pump (ESP), a method to supply the energy to produce from pressure-depleted or heavy oil wells was achieved. The tool string is long, but assembly is straightforward. At the bottom and below the packer are the TCP guns, along with their redundant firing heads. Next comes a succession of crossover adaptors, debris subs and tubing spacers whose purpose is to space out the interval between the packer and the guns.

When the packer is set on-depth, the guns will be positioned opposite the pay zone. Just above the packer are the safety joint and hydraulic jars, followed by the DST tools. The DST string varies according to the test objectives, but usually consists of a downhole sampler carrier and a downhole gauge adaptor, a pressure operated reference tool (PORT), and a pressure-controlled test valve (PCTV). Next is a single shot reversing valve, ESP, and a radioactive marker sub for depth control.

The ESP is contained in a pressure pod that isolates the pump from the pressure pulses used to actuate the TCP guns and operate the DST tools. The ESP is equipped with a variable speed drive (VSD) so different drawdowns can be imposed to create the required pressure transients. In addition, it has its own gauge that contains pressure/temperature sensors as well as pump and motor performance monitoring sensors.

In the case of heavy oil, an optional capillary tube can be run alongside the pump power cable so de-viscosifiers can be pumped in to improve crude mobility and the viscosity effects on the pump. Near the top end of the string, a “BOP can” is positioned opposite the blowout preventer rams. This provides a cylindrical surface for the rams to seal around to safely contain the well without crushing the power cable or capillary tube.

By assembling the three systems sequentially as the string is run into the well, maximum efficiency is achieved. At the same time, accuracy and measurement quality is assured.

Gauges are positioned at the appropriate place to accurately measure the data and avoid wellbore storage effects such that precise pressure transient analysis can be conducted and produce critical information about the reservoir characteristics. A new ESP design will further improve efficiency, using fully integrated or pre-assembled plug-and-play components that can be installed more quickly than conventional ESPs.

**Testing exploratory wells**

Although several applications of tool testing have been performed offshore and onshore around the world, Repsol YPF has used the technique successfully in a particularly challenging area. With an aggressive exploratory program consisting of 37 blocks under contract in the environmentally-sensitive Amazon rainforests of northeastern Peru, the company needed to test three exploratory wells.

Repsol YPF needed a solution for testing problems due to heavy oil, low formation pressure and an extremely remote location. Crude gravity in the discovery wells is less than 15 oAPI, and gas-oil ratio (GOR) is less than 40scf/stb. Although the rock properties are excellent, there is insufficient drive to produce the wells naturally to surface. The company feared the combination of low pressure and viscous crude would prevent acquisition of valid well tests because there would be insufficient energy to create a stable dynamic flow regime. Because the wells were exploratory, there was little local reservoir knowledge on which to base correlations.

The remoteness of the area created logistical problems as well as environmental concerns that added to the operational risk. Planning and efficient use of resources along with seamless integration between operating and service company personnel is fundamental to success.

The TCP/DST combination was run in the first two wells followed by an ESP run that included pressure/temperature sensors to monitor the productivity index of the wells. The objective of the test was to determine the IPR and estimate the reservoir pressure. Three successive flow tests were attempted, and although clean build-up curves were obtained, it was determined that very little oil was flowing—the flow was mostly mud filtrate from the near-wellbore region.

The purpose of the ESP run was to provide enough energy to lift the produced fluids to the surface and to allow the well to clean up. Various drawdowns of varying durations were imposed by adjusting the pump speed, and build-ups were obtained by shutting in the well at the surface.

**Triple combo third well**

With reasonable success on the first two wells, the operator agreed to try the triple combo test string on the third well. Two zones were tested. The first zone used the TCP/DST combo technique similar to the second well. The upper zone received the triple combo treatment with ESP included in the test string.

Testing sequence varied from the previous wells. After firing the TCP guns underbalanced, the well was allowed to flow naturally for an hour. Then it was shut-in at the PCTV for a 2.5 hr build-up period. After the PCTV was opened, the ESP was started and run at 40 Hz through a 32/64-in. adjustable choke for 6 hrs. The pump frequency was raised to 47 Hz and run for another 6 hrs. Then the pump was stopped for 24 hrs to allow pressure build-up to occur.

The next day the PCTV was opened, and the ESP was re-started at 40Hz and run for 1.2 hrs. Pump frequency was raised to 68Hz and the choke was opened to 36/64 for 3.0 hrs. Then the pump speed was raised to 70 Hz and run for 3.5 hrs. After this run, the PCTV was closed and the ESP was stopped for a build up period of 16.25 hrs. The ESP was restarted at 40 Hz with the choke adjusted back to 32/64, and then the speed was raised gradually to 70Hz and held for 2.25 hrs. A final step was to open the reverse circulation valve to circulate from the annulus up through the tubing. The ESP test sequence lasted a total of 65.7 hrs.

The test data were used to generate both a productivity index curve over time and an IPR curve pressure transient analysis. Compared to the other two wells the third well test was about 25% more efficient saving time and money. The data obtained was used to calculate average permeability, skin, reservoir pressure and the flow regime for the reservoir with confidence.