What’s your well’s IQ?

Intelligent Well Systems (IWS) are growing in popularity and application. Here’s one company’s take on where the market is, and where it’s going.

DICK GHISELIN, Production and Drilling Editor

In preparation for this article, we reviewed current technology, benchmarked with the recent Intelligent Wells Forum conducted in Galveston. Then we spoke at length with Donnie Ross, Advanced Completions Product Champion at Schlumberger. Donnie’s responses to our questions are summarized below.

Where are the hot areas in IWS? Which markets benefit most from the technology?
There are applications of advanced completions in several different categories. First, they allow us to use formation gas at discrete positions to help us lift liquid. Second, production optimization across several different targets is actually creating a new market today. Prior to this companies didn’t normally go into several (three or four) different targets in a well and penetrate them all because they weren’t sure of the value. Today, this can be effectively done without intervention. This permits revisiting existing Brownfields to develop that market, going for targets that had never been penetrated before.

Are those Brownfield zones being produced commingled? They can be produced either way — selective or commingled. Several technologies are available today that allow allocation of zonal production, for example the FloWatcher density tool from Schlumberger. This measures exactly what’s coming from each zone. The biggest issue is underperformance. If production is commingled, we have to be able to assure the operator that production is not flowing back into other zones. The pressure drop across the flow valves can be managed so production can be allocated properly to every zone using this tool.

With sustained high prices for oil and gas, what’s keeping some operators from jumping on this technology? This fits into the field life allocation concept. The gist of that is accelerated production.

Flow simulation is used to derive the optimum value of production in advance so the correct advanced completion can be designed. By simulating optimum production, it helps show the operator the value of the final completion once it’s in the ground. Depending on the operator’s drivers, we look at accelerated production, or we can look at NPV over the life of the well, or 20 years, whichever is first. Simulations are run that compare producing from one zone as fast as possible and then closing it off and moving to the next zone, or producing simultaneously from multiple zones, whichever makes financial sense.

In deepwater and subsea applications in general, the key drivers are risk and the cost of intervention. Very high reliability flow control devices and monitoring equipment are needed. While some say the objective of advanced completions is to forestall intervention, or extend the cycle, we believe that we can provide a planned completion equipped with high reliability components that will effectively eliminate the need to intervene in the well over its economic life. So planning must be more precise if life-of-well completions are to result. The key to accomplishing this is to get involved earlier in the process as a part of the reservoir management team so we can have access to the data we need to perform the best quality simulations, both in the completion itself and in the near-wellbore model. Intimate knowledge of the operator’s economic model is needed to design a complementary completion. The objective is managing accelerated production and/or increasing reserves. Another way to reduce risk is through experience. In this area, a few forward-looking operators are providing the opportunity needed to prove risk can be reduced to acceptable levels — companies like Norsk Hydro and Shell, among others. Performing satisfactorily for these visionary companies will convince others of our abilities and the market will grow quickly. At the same time it must be said that if an advanced completion doesn’t make sense for a particular situation, then the simulation will bring this out, saving the operator from installing completions he doesn’t need. If we can’t show up front that the completion will bring value, and by this I mean quantified value, then we should not be recommending it.

For IWS to be successful, three things are needed: reliable downhole adjustable chokes or valves, an accurate real-time monitoring capability that measures and transmits the correct parameters, and a robust dynamic reservoir model with simulation capability. Where are the strengths? Where is more work needed? The perception regarding the three components goes back to the definition of advanced completions, and this is certainly correct. A robust advanced completion system exists today, for implementing a choke device at the sandface, including the necessary measurements and data transmission capability. But it is necessary to close the gaps between the well model and the full-field development model, to ensure that the application of that advanced completion system makes sense. At Schlumberger, DCS (Data Consulting Services) accomplishes this by looking at fields for their customers at an early stage and developing candidates for advanced completions. Both the wellbore and the near-wellbore areas are examined, and advanced simulated completions can reveal, over time, which perform best. Using this approach all aspects of the problem can be considered and the full measure of our resources can be applied to solve it — electrical submersible pumping systems, sandface control integral with flow control and measurements, and new technologies such as distributed temperature sensors (DTS) over the completion.

How are fiber optics integrated into the intelligent well portfolio? Fiber optics is just another component of reservoir monitoring and control. Joining electrical pressure and temperature sensors, FloWatcher density devices and electrical water cut meters are fiber optics. It offers another component — for example, high temperature applications — for pressure, and DTS, which is pumpdown-able technology. Because the fiber is pumppable, it is not necessary to plan for this way in advance as for other aspects of the completion. This allows entering a well that is already completed, pumping down a fiber, and making a “thermal map” or thermal node from sandface to surface to give information on what’s happening with production. At any time during the life of the well, the fiber can
be pumped back out and a new one installed. As a result, operators to take advantage of new fiber-enabled technologies such as flow measurements and in-well seismic sensors. Fiber optics augments the well-watcher suite of technologies.

Electrical Dry-Mate Connectors (EDMC) technology is significant in the area of connector deployment in subsea, artificial lift, extended reach wells, etc. because they provide a highly reliable solution to one of the biggest problems in subsea or deepwater completions. Particularly important for permanent downhole monitoring and control devices, EDMC completely removes the failure mechanism associated with the feed-through connectors at both the production packer and the subsea hanger. It gives a complete sealed system with no chance of a leak. EDMC also allows more sensors to be placed in the production zone. With EDMC technology sensors can be placed reliably below the packer. This is very important for extended reach, horizontal and multilateral wells because it gets the sensors closer to the sandface. This removes the single largest failure mechanism from the system.

By monitoring all the wells in a reservoir in some fashion, prediction or modeling in a macro sense, can indicate how the reservoir is draining. This in turn allows operators to know which wells will require attention in time to deploy fiber optic sensors to get the detailed measurements needed to optimize production for the entire reservoir.

**Where is the industry on the electric vs. hydraulic issue? We have seen lots of hydraulic solutions lately (TRFC-H and Baker’s HCM-AT) what is the status of the electrically powered valves?**

Hydraulic technology has been in use for a very long time. It is very reliable and well understood. The Tubing Retrievable Flow Control – Hydraulic (TRFC-H) is one component of the flow control valves technology that is based on technology from some 600 deepset safety valves that have been installed so it is very reliable. The TRFC-H itself has now been deployed in 30-40 wells worldwide, and many more applications for the technology have been identified. Of course, it must be deployed in combination with sensors to monitor production, transmission systems to get the data to surface, and dynamic models that turn the data into useful information. One of the biggest advantages of the TRFC-H is that it only requires a single control line. The tool is controlled and operated by coded pressure pulses over the single line. A problem in many older wellheads is the limited number of through-ports for control and monitor lines. Other hydraulic and electrical valves require multiple control lines, making them unsuitable for use in many wells.

Schlumberger started permanent downhole monitoring in 1973. That has evolved to an electrical control system, the TRFC-E. The application is when there are three or four different zones to produce multiple valves can be dropped on a single electrical cable. In fact it is possible to operate 260 different downhole “nodes” on a single twisted pair using our WellNET technology. It allows measurement of pressure, temperature, flow, etc. and control of multiple zones, either separately or commingled. The TRFC-E also has a single feed-through so it passes through the wellhead or production packer quite easily. In addition, the WellNET telemetry has been specially designed to operate in wells with ESPs, where inherently there is a lot of electrical “noise.”

**What other technologies complement IWS and how are they being positioned as a part of the total production optimization solutions package? In other words, what’s new?**

Schlumberger’s sand control group is looking into the impact of integrating sand control with flow control. For example, fiber optics sensors can be pumped down the shunt tube of a gravel pack completion to measure internal and external flow around the pack. This was done for BP in Trinidad in a multiwell project that is ongoing today. Zones can be isolated using external casing packers in combination with flow control devices to try to even out production over the entire length of the screened completion. Another application is multilateral wells where two or more wells can link to a single motherhboard. At surface the PhaseTester and PhaseWatcher tools make their measurements without the necessity to separate the oil, water and gas.

**Where do you see the IWS market going, what are the challenges? The opportunities?**

There are many opportunities across a wide spectrum of applications whether it is production optimization, interventionless applications, or subsea developments, which are 5 to 7 year projects and are very complex in terms of architecture. In addition to subsea surface facilities and onshore terminals must be considered. Brownfields are opening up and we’re now going into areas where economics never permitted us to go before. Flow control is opening up all these markets. However, one of the biggest benefits of advanced completions is that they provide hard data on which to base performance metrics. These in turn allow service providers to accept more risk, which can reduce the customer’s up-front investment.