EXPLORATION & PRODUCTION | MACHINE LEARNING | ARTIFICIAL INTELLIGENCE

The Future of Intelligent Wells? Even Smarter

Downhole components are also increasingly coping with higher pressure and temperature conditions and handling more zones than ever.

By Jennifer Pallanich, Hart Energy   Tue, 11/28/2023 - 09:40 AM

Production from optimized wells is higher than output from conventional wells in similar reservoirs. (Source: Shutterstock)

In the quarter century since smart wells first splashed into the offshore, electronics and communications advances have made it easier than ever to control wells from afar.

Smart wells debuted offshore where intervening in a well can be costly, time-consuming and difficult.

Typically, operators isolate reservoirs with a packer, or sleeve that can open and close to allow hydrocarbons to flow out of or remain in the reservoir. As the reservoir changes and produces more water, different zones may need to be opened or closed. That raises questions like how to shift that tool, and how to know which reservoir to close.

Smart wells provide those answers, said Alan McLauchlan, principal product champion for all electric systems at Halliburton. He participated in the first smart well installation in the North Sea in 1997.

The first intelligent completion, deployed offshore Norway in 1997. (Source: Halliburton)

The main components of a smart well include a packer, downhole gauges to measure pressure and temperature and an interval control valve (ICV) for each of the zones that need to be controlled.

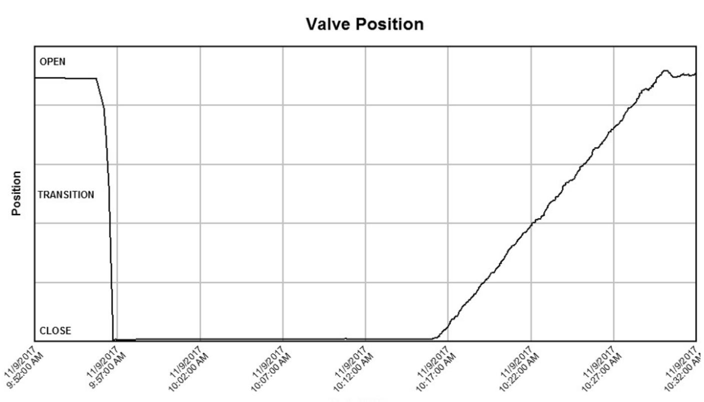
"With intelligent wells, with all the data coming to surface, in many cases, you don't have to wait until water is produced to react," McLauchlan told Hart Energy. "The operator can look at the data and then optimize the valves over time to increase production of the well and increase ultimate recovery when compared to conventional types of completions."

While the principles behind smart wells remain the same from the first deployment to today, technology has evolved, much as the cell phone evolved over the same time frame.

"What has changed is mainly regarding the downhole gauge technology, which have electronics," he said. "When we look at the downhole gauges, the electronics that we deployed at the beginning, they were typically limited to about 100 [C] to 125 Celsius."

Now, operators are pushing for equipment that can handle harsher conditions, including much higher temperatures and pressures reaching 25,000 psi and higher, he said.

"We're seeing customers really push for higher temperature capabilities, which, especially for electronics, that's always the challenge for electronics. Heat is not a friend of electronics."



With Halliburton's All-Electric Systems, a real-time connection makes it possible to understand exactly where the valve is at any time. In this example, a similar system, the electric safety valve, was deployed in 2016. The chart shows the system closing quickly, just like a conventional valve, but when opening, small changes in the opening (little blips) indicate small changes that could indicate scale in the well. This information is critical in understanding if a tool is within normal operating parameters, which is not easily achieved with a conventional hydraulic system. This feature will be standard on the All-Electric Intelligent ICVs. (Source: Halliburton)

The internal control valves (ICVs), similarly, need to be more robust and able to handle higher pressure differentials, flow rates and vibration, along with varied well conditions.

"The ICVs are designed and developed to withstand those types of conditions and be able to operate for 20 plus years," he said.

The electronics for smart wells evolved from 12-in. printed circuit boards to the size of a thumbnail.

"They're that small, and so they're significantly more power efficient. They're able [to] withstand temperatures, cases over 200 Celsius," McLauchlan said.

In its early days, the technology created head-scratching moments as reservoir engineers studied the data generated by opening or closing a sleeve, he said.

"When it came to being able to selectively choke an ICV and then look at the impact and the reservoir, there was a lot of unknowns. This was the first time that this was being done," McLauchlan recalled. "At the beginning there was a lot of head scratching moments, the reservoir people and the production people going, 'You know what, I didn't expect that.'"

The technology taught the industry a lot of lessons as it worked to understand the cause and effect of choking ICVs downhole, he said.

"Today, we have much better visibility of being able to understand with the data what can happen when we try to move things in the well," he said.

And that visibility pairs up with software apps, real-time data and alerts that pop up on customer phones when something changes in a well, providing feedback on opportunities for improving production, he said.

"We've definitely come a long way from trying to figure out, 'What does it mean?' So now we're at a point now where we have a tremendous amount of understanding to really help optimize these wells," McLauchlan said.

Bigger and better

To that point, he said, customers indicate that production from optimized wells is higher than output from conventional wells in similar reservoirs.

"It's just that ability to be able to react in real time and be able to operate something before a reservoir probably goes into too much decline, then that can obviously have production benefits for our customers," he said.

But not every well is a candidate.

In the 25 years since initial deployment, the tech has been used in more than 1,500 wells worldwide, with more than 3,000 zones completed. At first, it was used to handle no more than four zones in a reservoir, but the technology now has been used to control up to a dozen zones, he said. The first 12-zone installation was done in 2023 in the Middle East.

The first 12-zone intelligent well, installed in 2023 in the Middle East. (Source: Halliburton)

"The technology is being pushed even further, where now we can have tremendous amount of control over multiple reservoirs all from a single well," he said.

Initially, the technology made the most sense in subsea applications, and that was followed by installations at wells being served by platforms. In the last decade, McLauchlan said, there has been an uptick in land applications, particularly trending in Middle East land wells.

And whereas the smart well was at first used for oil wells, operators installed the technology in water and gas injection wells and are discussing its potential for carbon capture and storage applications.

"We're starting to see it being used for many more applications than what we envisioned at the beginning," he said.

The boost to production aside, one of the biggest benefits of the technology is that remote capabilities remove the necessity of sending people to well sites, he said.

It is "pretty exciting" to control a reservoir via ICVs from so far away, he said.

"What was neat was we'd watch the effects, so as they were flaring off or as they were producing to surface, as we controlled those valves, there would be a small delay and then you would see that impact on surface," he said. "It was pretty exciting to see that changing, you having control over something that's so far away below the seabed."

Smart well completions can be hydraulic, hydraulic-electric or all-electric.

"With these all-electric systems, now we have even more feedback that's coming to us. So little things like when we move a valve, as well as being able to see exactly where the valve is, we can monitor all sorts of different parameters that really not only tell us what's happening to the valve that is functioning, but also we can start to see small changes in the well conditions," McLauchlan said.

And those small changes include things like scale buildup, which could not be seen before.

"We have such fine resolution with these sensors that we can see a lot more than we did previously," he said.

The hydraulic-electric and all-electric systems allow for finer control of the reservoir due to the ability to monitor small changes in performance combined with digital integration of data and software applications.

"Over the next year or two, we're going to see some pretty amazing insights using AI and machine learning type models," he said. "Our vision for this is almost like an operator walking into the office and saying to their remote assistant, 'Hey, what do I need to do today?' And it's giving guidance on where it sees opportunity for increases in production, or 'We see water starting to happen, this is what you should do.'"

In short, he said, the systems will become "extremely smart" and act as guidance tools for operators, McLauchlan said.