Critical D&C issues with Carl Montgomery, ConocoPhillips

Selective isolation technologies still falling short

By Jerry Greenberg, contributing editor

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Carl T Montgomery

DC: What effect are lower oil prices having on your business?

Montgomery: A lot of these price indexes that the industry has been working on have caused budgets to decline. Some projects could shut down. It doesn't affect me too much on the service work. The drillers get hit real hard. They are the first ones to get shut down because of the oil price. My business actually increases a little bit because you still have to make up the oil somewhere. We do more stimulation work on older wells. Instead of frac'ing new wells, we are frac'ing old wells.

DC: Why wouldn't you see workover activity increase when you have $100-plus oil? Wouldn't it be more economical in some cases than drilling and completing a new well?

Montgomery: Because the new wells are coming on line, and we have to treat those. There are only a few people who do that kind of work, so if a well breaks, they just wait, because operators are looking for that early production from new wells where the rates are high. A lot of times, the workover work would have to wait depending on the well. For example, it costs us over a million dollars to pull and change a pump in Alaska.

It depends on where you are, of course. West Texas is a different scenario. A lot of times it is very expensive to come and work over these wells, so a lot of that workover just waits. But in order to get their production up, they will come back and set re-fracs in the area, go to wells that may be at a steady production rate and refrac them and get some good reserves in there. We don't have to complete it, and it is cheap to do that.

PetroAlliance is performing a proppant fracturing job on a Lukoil well near Kogalym in Western Siberia. Demand for workover on old wells is high in Western Siberian regions, especially when oil prices drop, said ConocoPhillips' Carl Montgomery.

Most of my work now is with Russian companies in Western Siberia. I would say about 60% of the work that I have been involved with there is workover. They have a lot of old wells, and they are working those over. When the oil price drops, that shifts it to something like 70% old wells and 30% new wells. The new wells never go away, but the ratio shifts.

DC: Are Russian operators using the same completion or workover methods as in the US?

Montgomery: The operators there are missing about half of the reserves that they have there. Some of the wells I have looked at are completely missing reserves. They are also using technology I had never encountered until I went to Russia that we probably should be using (in the US) and in other regions. But it has to do with knowledge-sharing.

The Russian operators and their service companies perforate their wells with what basically is a casing cutter. The tool has two large "wheels" that come out of it that look like glass cutters. They are "rolled" against the casing, exert pressure on the casing, and they basically split the casing until a slot is formed at the interval that the operator wants to perforate.

The service company then comes back and fracs the well. We run a scour stage up front, and that cleans out the near-wellbore area. You get a big pressure drop from that, but rather than having a single hole in there, this perforation is a 17-mm-wide and 4-m-long slot that runs up and down both sides of the casing. When I first saw this method, I thought that you basically are destroying the casing, and that is exactly what it does. But after you clean everything, you get very nice communication to the formation. And it is inexpensive. You can run it with a workover rig, so when you are running the tubing string in there, you perforate with the tubing string. You don't have to hire a perforating company.

DC: Could this method be used effectively in other areas of the world?

Montgomery: I don't know why it couldn't be. The Russians have been doing this for years. They use this method on about 70% of their wells.

This rig is being operated by Eurasia for Lukoil near Kogalym in Western Siberia. Russian operators and their service companies are perforating their wells with a casing cutter technique that appears to be effective and inexpensive, Mr Montgomery said.

DC: Would that be something you would be interested in exporting from Russia?

Montgomery: I'm not sure. I'm thinking about that possibility. One of these days when I have a marginal area where I have got a workover rig on there, I might try that.

DC: What else would the industry need to more effectively complete wells, new or old?

Montgomery: We need better selective zone isolation technology to produce the different zones.

It depends on what the lift mechanism is, in some cases. That is one of the big issues that we have on existing wells like these big gas wells in the North Sea. They drill a well and make 30-60 million cu ft per day, but that is out of the high permeable zones. So after they have blown a well down, there are lower permeable zones that still remain and a lot of reserves left in the well. It is very difficult to come back and work over that well because these low-pressure zones are mingled with the high-pressure zones.

Selective isolation is difficult and expensive. That is a mistake a lot of people make, and I fight that all the time. The best time to complete the well the way you want it is when it is a new well, when the pressures are all the same in the well. When you begin producing it, the differential pressures create all kinds of issues. Then the drillers have the same problems because you blow those wells down, and you have these very low-pressure areas where you need lighter mud. And right next to a high-pressure zone you may need to be able to control a potential blowout. Sometimes they cannot drill those wells because of that. A lot of the reserves are lost as a result.

Normally these wells will last between 15 and 20 years, and they start becoming marginally economic after about 10 to 12 or 15 years. That's when operators begin looking at ways to bring the production rates up on these wells, and that is when they start having those issues.

So the technology that is really missing is selective completions. The service companies have fracturing services where they set coiled tubing, but they are expensive and not that effective. What we need is something that results in better and more effective selective isolation. We run packer systems, and that is helping in cased-hole completion but not particularly in open-hole completions.

Selective isolation equipment such as packers and sleeves should be installed when the well is initially completed, but they are almost never done that way. I always preach that to people, that the best time to complete a well – to frac it, for example – is when it is a brand-new well. Don't wait until differential pressure begins. There are companies that are working the whole issue of selective isolation. It is pretty important.

DC: With shale plays receiving a lot of attention, what are some of the issues and challenges to more effectively and efficiently completing and draining those reserves?

Montgomery: The one area the industry needs to work on that is not there yet is in unconventional shale plays, such as the Barnett and Bakken shale and shale plays in the eastern US. There is a lot of work going on in unconventional shale gas systems, and the way they are completing those wells is using multi-stage packer systems. Industry is performing water fracs on them, just pumping water, a low-viscosity fluid with low concentrations of sand, and the fluid opens up these natural fracture networks. They pump small amounts of proppant with lots of fluid, and it works pretty well.

But that technology was built in 1957. We need a Water Frac 2010, or 2009. I used to call it Water Frac 2008, but nothing has happened so far. I think there are some materials that we can put into the fluid that will change the strength of the rock to improve the effectiveness of the fracture itself. I think there is an opportunity for the service companies to come up with a new stimulation fluid for gas shale plays or unconventional shale gas.

DC: Are service companies working on the 2010 version of water frac?

Montgomery: I have talked to all of them. They haven't brought anything to me yet.

DC: Is it because the 1957 iteration is working as well as it needs to work?

Montgomery: I think part of it is because the people who are pumping the present iteration of fluids don't really recognize the issues, and they think it is good enough. Because if it is good enough, why change?

The interesting thing that I do in hydraulic fracturing, it is such a great technology that it is almost impossible to fail. If you frac a well and double the production, is that good enough? What if you had frac'd it correctly and tripled the production? But double the production is good enough, so that is where they go. Is a 50% solution good enough or should you be going for 80%?

It is very difficult to apply technology now (with oil prices below $60/bbl). Any time you do something new that is a little different, there is always the risk that something negative will happen. And it does happen. In order to overcome aversion to that risk, you could spend some money on the technology. I could do that for the first two or three wells, and if doesn't work, then we will stop. That is what we try to do. I have been pretty successful with that. I have had two new technologies that I took into the field last year, and both of them are doing well.

DC: Can you discuss those new technologies?

Montgomery: One of them involves the various types of packers. The other technology was about a change in fluid chemistries. Our North Sea business unit is in a technology development project with one of the service companies in the North Sea. We are running it in wells, and it looks like it is working pretty well, so the service company will probably take that tool and use it for some of our competitors.

The tool is a set of straddle packers that are run in on coiled tubing, and you pump in that packer set to ensure you get acid into every set of perforations. The tool is another selective isolation technique that you use on coiled tubing. As you are pumping it into the system, it sets packers across a set of perforations in a cased completion. It sets these packers at a certain pressure, and then you can inject your completion fluids. In this case, it is acid.

DC: You don't hear as much about smart wells or intelligent completions today as you did a few years ago. How is smart well or intelligent well completion technology progressing?

Montgomery: We had a huge effort geared toward that, but it has slowed significantly because of the lower oil price. I don't see the emphasis on this technology, primarily due to the cost associated with it.

DC: Did you see more such activity with oil prices above $100?

Montgomery: We saw more activity of trying to get them installed. There were two people in my group to solicit interest from the various business units, but I don't think one was actually installed. Those systems are very expensive.

Also, I don't think the technology is at the point where it is fully deployable. We have had several issues, perhaps the most important is the robustness necessary for the control lines to open and close sleeves. The sleeves are robust enough for downhole environments, but the control lines are where the issues are.

DC: But that depends on the level of intelligence installed, doesn't it? Some wells have a few sensors rather than a full-blown smart or intelligent completion.

Montgomery: The industry is running more completions like that, too. Digital fiber optic cables are a great technology. You don't just get one reading on it. If you can install it, it is downhole for at least three years. You can look at these production rates, you don't just have a single snapshot in time. But it suffers from the same thing that we were just talking about: It is very, very expensive to do that. I wanted to run one of these, and it was going to cost about $400,000.

DC: Was that the cost for minimal intelligence?

Montgomery: Yes, running a fiber optic cable was about $400,000. Would you do that in one well or go drill another well? For me, that answer is pretty easy. It is always nice to have that data, but it is expensive.

DC: Does it make a big difference in the well?

Montgomery: It may change the way you do things. For example if you had zones like those found in the Piceance Basin, it has 40 different sands. You run a completion and find out you are missing perhaps 10 of those sands. You didn't get any treatment into 10 of those sands, which means your completion is 75% effective, and that is not very good. You can help the well a lot if you can get the completion efficiency up to 95%. But once you learn how to do that, why do it any more?

So now you have learned what you need to learn, and you stop. And that is how I was trying to sell this fiber optic technology. The higher oil prices allow you to go out and try things you wouldn't normally try because there is a little money to take the risk out of it. But to get this new technology at $45 dollar oil, that money is just not there. The aversion to risk hasn't gone away. And the introduction of new technology becomes more difficult.