New Technologies Enhance Efficiency of Horizontal, Multistage Fracturing

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Significant differences in completion philosophy are emerging within our industry. Even companies that practice a factory mentality (one size/method fits all) are beginning to see that the "sledgehammer approach" to hydraulic fracturing may not be the most effective in draining horizontal wells in resource plays. For several years, we have seen massive increases in fluid volume, pumping rate, total proppant volume, and pumping time to increase recovery. We have seen through microseismic as well as fracturing into offset wells, that we are able to create massive and extremely long hydraulic fractures. Yet, when effective fracture length is calculated, the results are extremely disappointing. It only makes sense that "more is better." However, after years of steadily increasing job size, stage number, perforating strategy, proppant volume, and lateral length, the only one that stands out as consistently improving recoveries is *that more stages are required* to effectively drain microdarcy permeability rock (Rankin et al., 2010).

What We Have Learned

Building an understanding of shale gas, unconventional gas, tight carbonate reservoirs, and more recently the renewed emphasis on oil and high-liquid gas formations has not been easy. Perhaps this is because of the extremely rapid pace of development and the acceptable economics of many projects in North America and throughout the world. Also, the diversity of applications for horizontal, multistage fracturing has made it more difficult to pin down best practices. As a massive body of data develops, a number of things have become clear. First, when equivalent stage numbers and proppant volumes are considered, open hole generally seems to outperform cased hole by 25% to 70% in production (**Fig. 1,** Edwards et al., 2010; Snyder and Seale, 2010). Second, the number of stages required to effectively drain microdarcy permeability rock is extremely high. Just a few years ago, performing 20 stages seemed too high to consider. Current stage numbers are often double that. Third, today's common plug and perf practices—even at high densities—may not be sufficient to drain shale gas or tight oil, even after 15 years of depletion time (Quirk, 2010). Reservoir modeling indicates that evenly spaced fractures would effectively drain today's reservoirs in North America. The actual production data, however, indicates otherwise.

One example is the Horn River shale in British Columbia. Over the past few years, horizontal wells were, on average, drilled approximately 4,000 ft in length and fracture stimulated primarily with cemented liners and plug and perf methods. Fracture treatments on these wells have grown significantly and, more gradually, the number of stages has increased. One operator in the play recently published that it successfully performed 100 fracture stages on one of its wells (Busy Pressure-Pumping Market Lifts Calfrac Sails, Nov. 3, 2010). Ridiculous you say? Not necessarily. Recent developments in reservoir modeling indicate that even after 10 years of production using standard stage density (12 to 18

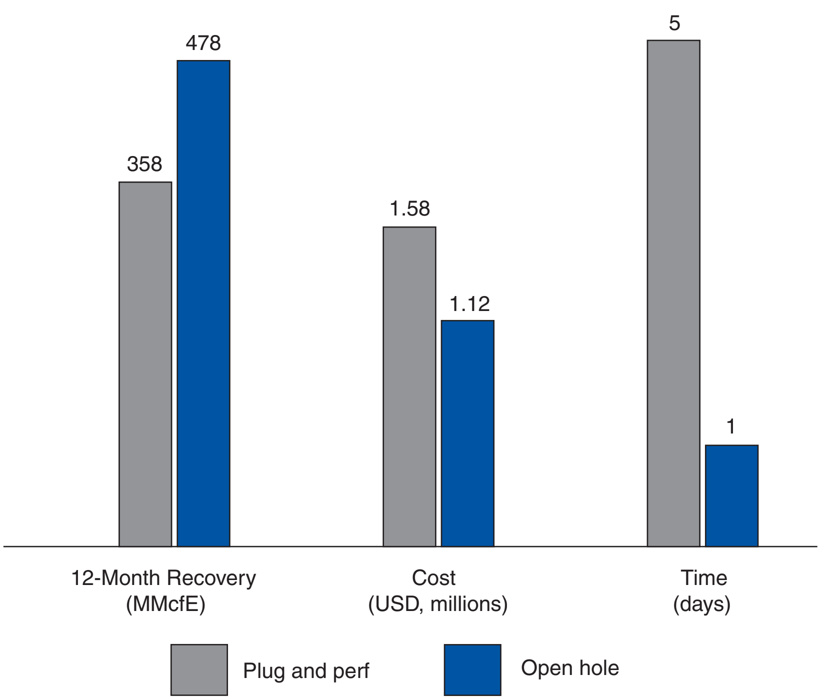

Fig. 1—Comparison of production and operational efficiency using open hole and cemented liner plug and perf methods (data from Edwards et al., 2010).

stages), there will be near original pressure between most fractures (Quirk, 2010). The problem with performing 100 fracture treatments is that the plug and perf process used took 40 days to complete operations. Forty days with frac fluid on formation in tight gas applications cannot be a good thing. In addition, supervision of fracture treatments, equipment on location, and the cost of the required infrastructure to support such an operation do begin to border on ridiculous.

The Move Toward Liquids

In many areas, long-reach laterals are being applied to make drilling and completion more efficient. We have recently completed a number of wells in excess of 10,000 ft in horizontal displacement—all in zone and all intervals requiring stimulation. Placement records so far have been 47 stages in a 9,300 ft horizontal well. However, the move away from gas toward oil and high-liquid reservoirs in microdarcy rock indicates that the current stage numbers may need to double for long-reach laterals. With the continued increase in stage number combined with the reduced mobility of liquids in tight rock, which requires higher fracture conductivity, a significant challenge lies ahead.

When evaluating high-liquid formations such as the Eagle Ford in south Texas or the Niobrara in eastern Colorado and adjacent areas of Wyoming, Nebraska, and Kansas, clearly more stages are imperative to achieve adequate drainage. If gas moving through shale rock has difficulty achieving depletion over long periods (years), then oil will be worse. What is interesting is that historic modeling software will often predict that drainage requires extremely long fractures to more effectively drain the reservoir, rather than multiple, short fractures. In most cases, however, the converse tends to be true (Rankin et al., 2010; Vincent, 2009), and the understanding of complex reservoirs in extremely tight rock indicates that planar fractures are probably the exception. Complex fractures are apparent in many areas and formations, and the ability to induce complex fractures may actually be preferable to long, planar fractures.

Where Are We Headed?

It appears that the key to successfully producing economic, long-life wells in many of these reservoirs may be performing 50 to 100 fracture treatments to achieve good drainage. The good news, however, is that it appears that effective drainage can be achieved with far smaller fracture treatments on a per-stage basis. Technological developments are, at least in part, the solution to making this feasible, both from a time of execution and a cost basis. If the consensus is that ultrahigh stage numbers are the answer, then this may produce a number of other benefits as well. Our industry is constantly under attack for massive utilization of water in hydraulic fracturing and then dealing with that water when it comes back to surface. We have seen operators in some areas decrease proppant volume by half and fluid volume by more than half, while increasing stage numbers. The results are overall improved production, considerably lower cost of fracture treatments, and what appears to be much better ultimate recovery.

New Technology Required

If the production data is correct—as numerous case studies have shown—that more stages will recover more reserves, then the trend toward tighter spacing between fractures is the correct direction. In most North American fields, the trend towards increasing stage number has been observed (Snyder and Seale, 2010). In the case of plug and perf cemented liners used in many shale developments, actual stage number has increased from about five a few years ago to eight or more—with three to four perf clusters per stage. The assumption is that this results in three to four fractures per stage, resulting in 20 to 30 fractures. A body of evidence, including both microseismic and production studies, is developing that shows this may not be the case. A recent production study discussing contributions from perforated stages stated that on the basis of production logging studies, only 30% of the intervals were actually contributing (Baihly et al., 2010). If this is correct, it will be very difficult to go beyond the current number of bridge plugs installed in a plug and perf completed well—because of simple economics and time required. With frac crews in high demand and short supply, the difficulty in getting additional frac days (including hydraulic horse power and support equipment for a day), and the climbing rig count—especially in oil and liquid-rich plays—the prospect does not look good for achieving drilling program targets if stage numbers are to increase beyond current levels. This is where technology advancements can help.

Stage multiplier technologies. Significant improvements affecting placement techniques and other factors in horizontal multistage fracturing have resulted from stage multiplier technologies. One new technology now in use to increase stage number is the repeatable port tool, which allows the same size ball to be dropped several times and precisely activates specific ports in the process. A version of the tool **(Fig. 2A)** that enables stage numbers to be doubled from previous levels, increasing from approximately 20 to 40 or more stages, was released in 2010. Subsequent versions will enable stage multiplication by a factor of four to six times current numbers. So, if a few years ago it seemed impossible even to consider pumping 40 individual fractures, stage multiplier technologies will not only make this possible, but make it easy to execute stage numbers approaching 100.

The added advantage of stage multiplier ports is that they allow the use of much larger ball seats. For applications requiring high pumping rates (95 to 125 bbl/min) during fracturing, ball-actuated ports may create some pressure drop. If the smallest seat size is increased, it will both reduce pressure drop while eliminating restriction that may make coiled tubing intervention difficult. Ball drop systems have proved the most efficient and effective method of advancing between fracture stages while allowing for accurate displacement, without shutting down operations.

Multiport fracturing technologies. Another key technology currently in use is QuickFrac, which provides for simultaneous fracture treatments to be performed through multiple ports. With this technology, simultaneous

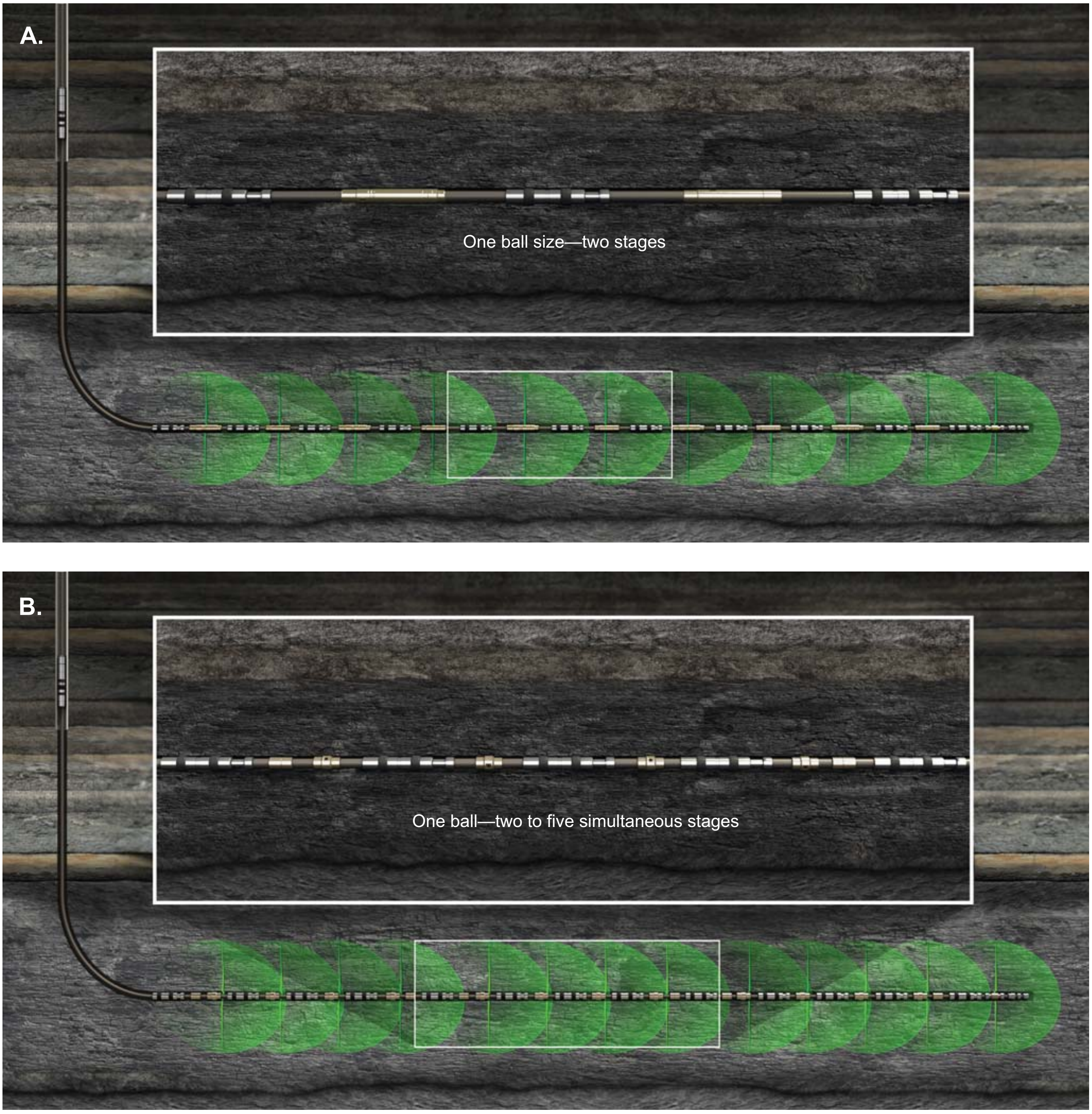

Fig. 2—Schematics for A) stage multiplier, and B) multiport fracturing technologies.

performance of two to five stages for each fracture treatment is possible **(Fig. 2B).** For example, if an operator were to place 60 fractures using this technology, the number of treatments pumped at surface would be approximately 15. Thus, the use of multiport fracturing technologies, combined with limited entry, makes it economic to place 60 or more stages.

Case Histories

Tight oil stimulation. A recent example of a multiport fracturing system in use was a job executed in Alberta's Cardium tight oil play. The objective was to pump a total of seven fracture treatments at surface, while actually attaining limited entry and producing 21 individual fractures downhole. At the start of each treatment, a ball-activated, multiport interval comprising three isolated stages was opened. Each interval contained a limited entry setting allowing only one third of the fluid pumped at surface to enter each isolated stage. The 21-stage job was successfully executed in only seven hours of pumping time, resulting in an approximately 60% reduction in total stimulation time compared with standard ball-drop systems.

Carbonate stimulation. Carbonate stimulation often requires a unique approach to system design because of formation variation. A recent example comes from the Arab D formation in the Middle East. A system was designed to enable both acid fracture treatment of tighter rock intervals and acid matrix stimulation of more prolific intervals. Standard fracture ports were used for acid fracture stages and four to six limited-entry multiports were placed within each acid matrix stage. The job was successfully pumped through a total of 12 ports, yet only four major stimulation treatments were pumped at surface. The result was an effective fit-for-purpose stimulation of the intervals: fracture treatment of the tighter intervals and matrix stimulation of the more prolific ones.

Conclusion

As our industry learns more about best practices in horizontal well stimulation (e.g., avoiding overdisplacement of fracture treatments, maintaining near wellbore conductivity, and creating effective fracture length) and adjusts to the new realities of historic modeling that do not fit our current resource plays, there are a number of opportunities on the horizon. Understanding that the current plug and perf methodologies will not likely take our industry where it needs to go, the answers are arising elsewhere.

New technologies currently being used in the field will continue to gain acceptance. First, it appears that the number of stages in nearly all tight plays needs to increase. Second, the "sledgehammer approach" to multistage fracturing, meaning ever larger fracture treatments with increasing amounts of sand and excessive use of water and hydraulic horsepower, is giving way to more technical approaches. More fracture stages, smaller fluid volumes, less sand per stage, and more effective placement represent the industry's new direction. Stage multiplier and multiport technologies can quickly bring us to high stage numbers without significantly increasing water use, required proppant volumes, supervision time, or hydraulic horsepower use. The ability to stimulate 60 or more stages effectively, while pumping only 15 treatments at surface is at hand. This new level of efficiency will open numerous opportunities for improving stimulation design and execution in the field. The overall goal is to increase ultimate recoveries. These types of technologies represent the best approach and are being used in the field today to meet challenging, emerging goals in multistage fracturing. **JPT**

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