PINPOINT FRAC-ISOLATION TECHNOLOGY COMBINED WITH MEASURED DOWNHOLE DATA ENABLES CONTROLLED OPTIMIZATION OF MULTISTAGE COMPLETIONS

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ABSTRACT

Today, E&P companies are being challenged more than ever before to improve economic performance. Since completions are the largest cost for multistage completions it is imperative to improve cycle time and maximize production results. A new approach to multistage completions combines predictable and verifiable frac spacing and propped volume with recorded bottom-hole pressures and temperatures to enable operators to progressively optimize stimulation designs and frac delivery across fields. The approach relies on pinpoint frac placement using a coiled-tubing-deployed frac-isolation system. The presentation describes the pinpoint stimulation technology, discusses the value of recorded down-hole pressure and temperature data, and reviews two optimization case histories.

INTRODUCTION

In today's low-commodity-price environment, operators are focusing on completion optimization as they seek to increase ultimate resource recovery from every well while keeping costs low. Optimizing multistage completions has one primary goal: obtain the maximum stimulated reservoir volume (SRV) at the lowest cost. To achieve the optimum balance between SRV and cost, operators must contend with a number of variables, including frac spacing, frac propped volume, proppant type and size, proppant concentration, fluid type, pump rates, and more. The inability to control the first two of these variables leads to a great deal of guesswork when comparing one completion against another. Yet with the two most commonly used multistage completion methods, unverifiable and unrepeatable frac placement not only hinders optimization, but also leaves a significant amount of reservoir unstimulated along the lateral—bypassed production that likely will never be recovered. By comparison, a newer pinpoint stimulation method delivers consistent frac placement that makes optimization possible and also creates a more efficient frac network.

CONVENTIONAL MULTISTAGE COMPLETION METHODS

The two most commonly used conventional completion methods are plug-and-perforate (PnP), a familiar technology that has been used for more than 50 years, and open-hole packers combined with ball-drop sleeves, a newer method that was introduced around the turn of the century. PnP had been used in vertical wells for many decades by the time the shale revolution occurred, and it was easily adapted for the multistage fracturing that was needed to economically produce very-low-permeability formations. With PnP, the annulus is cemented to provide the necessary pressure isolation between stages. Each stage typically contains four or five perforation clusters that are stimulated simultaneously, with a wireline-installed plug isolating the stage from the wellbore below.

As implied by the name, the open-hole method does not have cement in the annulus to isolate the stages. Instead, it deploys a liner with ball-drop sleeves and swellable packers to isolate sections of the wellbore, with the stimulation being pumped through the sleeves, which are sequentially opened using progressively larger actuating balls.

Both of these methods have a history of delivering economically successful wells. However, with the industry under heavy financial pressure, operators are striving to do better—to increase profit margins certainly, but also to maximize recovery of valuable resources.

THE CHALLENGE OF VARIABLE BREAKDOWN PRESSURES

As stated above, the first requirement for true completion optimization is the ability to control the placement and propped volume of each frac, so that well-to-well comparisons are valid.

The reason the older completion methods cannot deliver consistent frac placement is that breakdown pressures can differ by several thousand psi over the length of a single stage. When a PnP multicluster stage is fractured, the cluster opposite formation with the lowest breakdown pressure initiates first, often creating a "supercluster" that extends deep into the formation. Other clusters in that stage receive little or no proppant, leaving a significant portion of the lateral under-stimulated. There is no way to know this at surface during the completion. The operator knows how much proppant was pumped into the stage, but has no direct way of knowing how much proppant went into each cluster.

This limitation of PnP has long been recognized. In recent years, many studies have confirmed that as many as 40 percent of clusters are under-stimulated and contribute little or nothing to production. Three representative studies employed flowmeters (Miller, Camron et al), tracers (Castro, Luis et al), and fiber optics (Ugueto, Gustavo, et al) to clearly define completion effectiveness. **Figure 1**, which is based on the results of published studies, shows what a four-well PnP frac network might look like. Frac location and size are random and unpredictable, leaving much of the reservoir along the lateral under-stimulated and making well-to-well completion optimization very difficult, if not impossible.

Operators have addressed the problem of variable breakdown pressures by increasing the stage and cluster count or by employing various kinds of chemical and mechanical diverters. Although these can smooth out some of the randomness, frac location and size are still unpredictable, unverifiable, and unrepeatable. The only sure way to achieve consistent frac delivery with PnP—to know exactly where fracs are and how much proppant they receive—would be to execute them one at a time, which isn't practical for a large number of stages.

A similar scenario plays out with an open-hole completion. Depending on breakdown pressures, fracs can initiate anywhere between the swellable packers, which are hundreds of feet apart. While the sleeves are predictably spaced, fracs can initiate anywhere between the isolation packers, which are typically hundreds of feet apart. The operator has no direct way of knowing the number, size, or location of the fractures.

Unless they deploy fiber optic sensors during the stimulation, operators obtain no downhole information when they use either of these two methods, which bullhead frac fluids down the casing and provide no feedback about formation response at the frac zone.

CONSISTENT FRAC DELIVERY ENABLES CONTROLLED OPTIMIZATION

In recent years, a third multistage completion method has gained popularity: coiled-tubing fracturing delivers pinpoint (also called single-point) fracturing, which provides the predictability, verifiability, and repeatability needed to truly optimize completion designs from well to well. At the end of the stimulation, the operator is certain where each frac initiated and how much proppant was pumped into it, thus controlling two important completion variables. This method has the additional benefit of employing down-hole gauge/recorders that measure pressure and temperature during the stimulation, providing valuable insights about the treatment, the well, and the formation. **Figure 2** illustrates a four-well frac network having consistent frac placement and propped volume. There is much less unstimulated reservoir volume, and the completion is repeatable from well to well.

The coiled-tubing frac method system ensures consistent frac placement by combining cemented casing sleeves with a coiled-tubing-deployed frac-isolation tool assembly. As with PnP, a cemented annulus provides pressure isolation between stages. The casing sleeves **(Figure 3**) are run as part of the liner or casing at the end of the drilling phase. During the completion phase, the frac-isolation assembly (**Figure 4)** is deployed on coiled tubing to open casing sleeves and fracture one single-point stage at a time. The frac-isolation assembly comprises a multi-set bridge plug (the isolation element), sleeve locator, and two downhole gauge/recorders. At each stage, the resettable bridge plug seals to isolate the frac stage from the wellbore below and grips the inner barrel of the sliding sleeve for shifting.

Completions begin at the toe of the well, with the frac-isolation assembly positioned below the sliding sleeve. The isolation assembly is pulled upward, and the integral sleeve locator snaps into a recess at the bottom of the sliding sleeve. The bridge plug is then set against the sleeve's inner barrel by applying the coiled tubing set-down weight. An increase in wellbore pressure from above forces the bridge plug and inner barrel down to open the sleeve's frac ports to the formation. Sleeve shifting is verified at the surface by weight and pressure. The frac is then pumped down the coiled tubing/casing annulus. Once the frac is away, a pull on the coiled tubing opens an equalizing valve and unsets the bridge plug. The tool assembly is moved up to the next sleeve, where the sequence is repeated. After the last stage, the isolation tool assembly is pulled from the well and the unrestricted wellbore is ready for production.

THE VALUE OF MEASURED DOWNHOLE DATA

In addition to consistent frac delivery, the coiled-tubing fracturing system provides valuable, measured downhole data to help the operator better understand the formation, the well, and the stimulation. Two high-resolution gauge/recorders on the coiled-tubing frac-isolation assembly, one above the isolation element and one below, record downhole pressure and temperature. The top gauge measures frac-zone pressure and temperature, and the bottom gauge measures pressure and temperature in the wellbore below **(Figures 5 and 6**). Neither PnP nor ball-drop-sleeve completions provide any downhole data.

The primary use of the pressure data is optimizing spacing between fractures. The gauges detect pressure communication if it occurs between stages, which indicates that the stages are too close together. Careful analysis of the pressure data can also identify the type of interzone communication—natural fractures, cement failure, or longitudinal fracs. Pressure data analysis can also reveal the presence and cause of near-wellbore restrictions or proppant bridging. The completions team uses this information to determine minimum frac spacing, a key data point when optimizing the number and spacing of stages.

Recorded temperatures depict the cooling of the frac zone as the frac fluid flows into the formation. At the same time, the lower temperature gauge captures the gradual warming of the zone below as it returns to normal formation temperature. When anomalous conditions occurs, such as slight fluid communication through microannuli, or frac fluid flowing down along the wellbore before propagating out into the formation, it is reflected by a cooling at the lower temperature gauge.

The actual cool-down and warm-up temperatures are also valuable for designing and testing (optimizing) crosslinkers and breakers, which are usually developed based on estimated bottom-hole temperatures in the absence of actual measurements.

At the same time, the coiled-tubing "deadleg" communicates downhole pressures from the frac zone to the surface in real time, which allows for frac optimization during the stimulation job. The operator can adjust parameters such as pad size, pump rates, and sand concentration and ramp from stage to stage while moving up the wellbore. Based on actual formation response, one can look for pressure buildup ahead of a screenout and adjust accordingly by lowering pump rates or cutting back on sand concentration in the stimulation fluid. If a screenout were to occur, the system can circulate fluids to quickly remove excess proppant without tripping out of the hole.

CASE HISTORY 1

An operator working in the deep Montney formation in western Alberta, Canada had achieved reasonable production results using plug-and-perf completions but wanted to trial the single-point frac-isolation assembly with a goal of improving reservoir coverage. They also wanted to eliminate the plug-and-perf risks associated with screenouts and early plug setting.

On the first well with the pinpoint completion assembly, the operator was able to adjust the frac design as they moved up the wellbore by watching bottomhole pressure in real time via the coiled tubing deadleg. The initial maximum treating rate in the first well was 34 bbl/min, with an average sand concentration of 1.4 lb/gal. By stage 15, the operator gained the confidence to increase pumping rate to 37.5 bbl/min and sand concentration to more than 1.75 lb/gal. This optimized frac design was used in the subsequent wells.

In addition, recorded pressure data from the downhole gauges confirmed that there was no communication between zones. This prompted the operator to reduce spacing from about 130 ft to less than 100 ft and increase the number of stages to significantly increase reservoir contact. With each new well, the operator further tightened spacing between stages. They tested spacing as close as 52 ft, but finally determined that 72 ft was optimal for their well design. On the ninth well, the operator successfully placed 97 stages in a 7,000-ft lateral (**Figure 7**).

In addition to optimizing stage treatment strategy and frac spacing, the operator achieved higher production and an average 8% reduction in the cost of placing proppant, compared to plug-and-perf, saving approximately $600,000 per well.

CASE HISTORY 2

Another operator used the pinpoint frac-isolation assembly to standardize completions in and around the Viewfield Bakken play in southeast Saskatchewan, Canada. The operator had used a traditional open-hole completion method prior to making the switch to pinpoint hydraulic fracturing in 2012.

The operator began experimenting with 16 stages per well, but anticipated improvements to net present value (NPV) and estimated ultimate recovery (EUR) prompted them to experiment with more optimal stage-spacing strategies. They are currently using a standard design of 25 stages per well, resulting in a per-well NPV that is more than three times the initial value and EURs that have improved from 100,000 bbl to 250,000 bbl. The increased EUR per well significantly lifted the operator's booked reserves, while the increased NPV per well provided superior economics and allowed them to continue drilling in the current environment of low oil prices.

AUTHOR BIOGRAPHY

Jason Frost began his career in the oil and gas Industry in 2004 and has more than 11 years of experience in onshore and offshore operations and sales. He is currently the U.S Business Development Manager for NCS Multistage, LLC, based in Midland, TX, where he introduces new and existing clients to NCS Multistage technology. His previous experience includes subsea engineering and he most recently worked for a major service provider where he was an account manager and multi-product line completions coordinator. Frost received an A.S. in Biology from Louisiana Tech University while gaining valuable industry experience. His work with business development strategies and his ability to apply new technology have seen industry wide recognition and resulted in a world-record completion in the Permian Basin.

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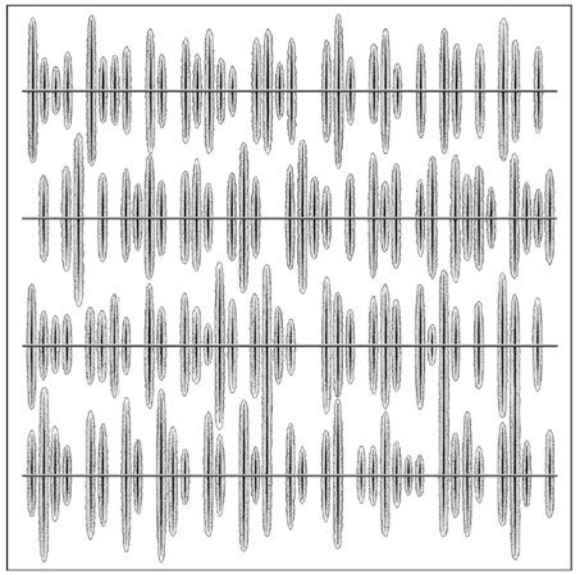

Figure 1. This conceptual sketch depicts a PnP section with uncontrolled frac placement due to variable breakdown pressures, resulting in significant unstimulated reservoir volume.

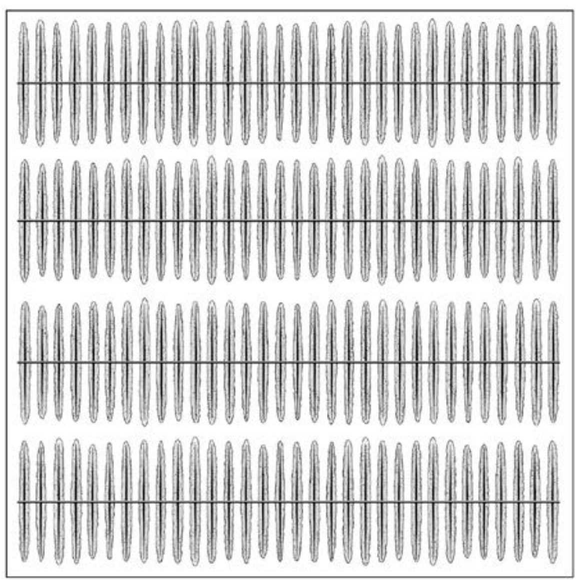

Figure 2. An ideal optimized frac network has equally spaced fracs with equal propped volume, leaving a minimum of unstimulated reservoir volume.

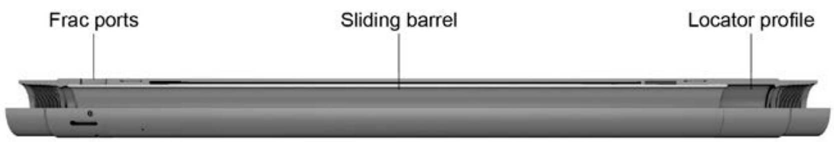

Figure 3. The cemented sliding sleeve

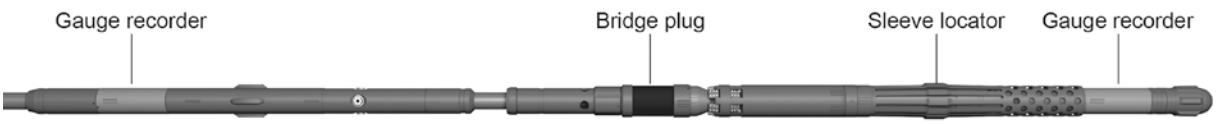

Figure 4. Components of the frac-isolation assembly

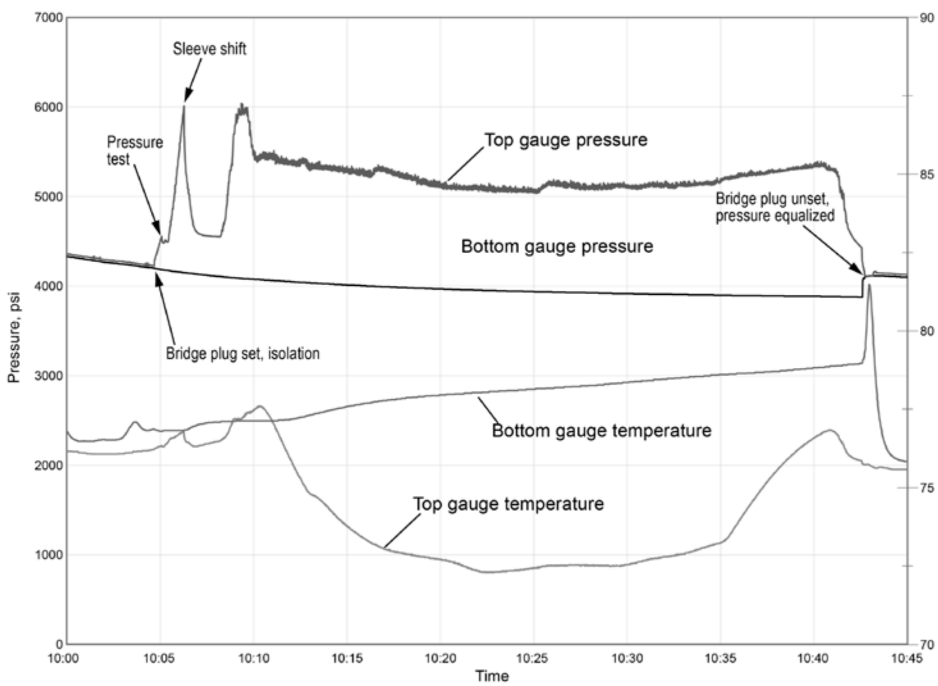

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Figure 5. Measured pressure and temperature data from a single frac stage. Pressure readings confirm isolation from the stage below. Top gauge temperature shows the cooling effect of the frac fluid, while bottom gauge temperature shows the gradual warming of the previously stimulated stage below.

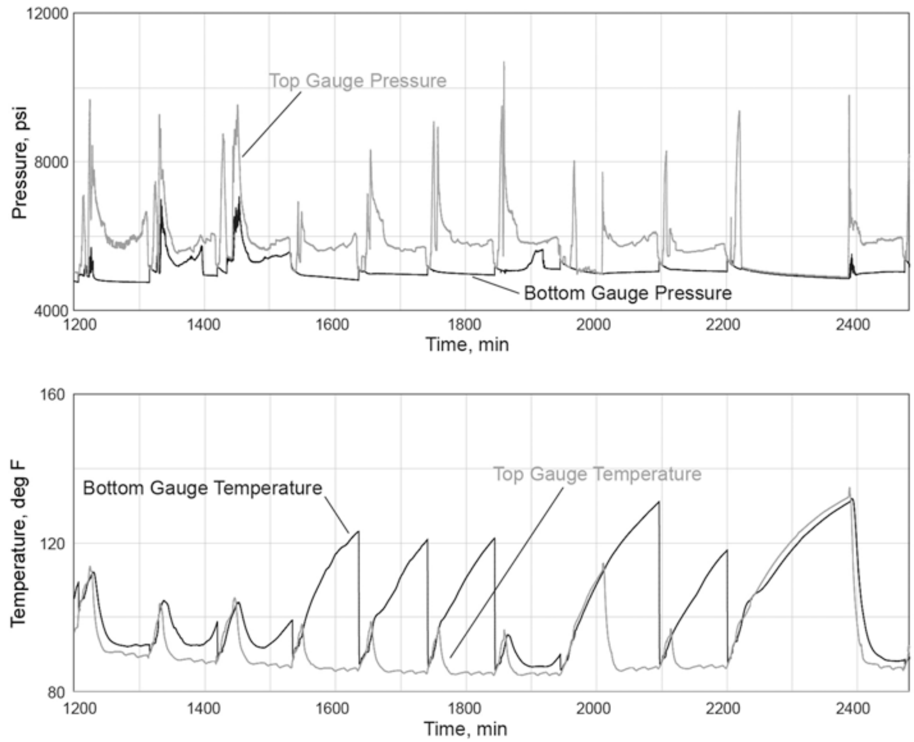

Figure 6. These charts show pressure and temperature above and below the isolation assembly for ten frac stages. The data reveal and describe any interzone communication as well as characteristics of the formation, well, and stimulation.

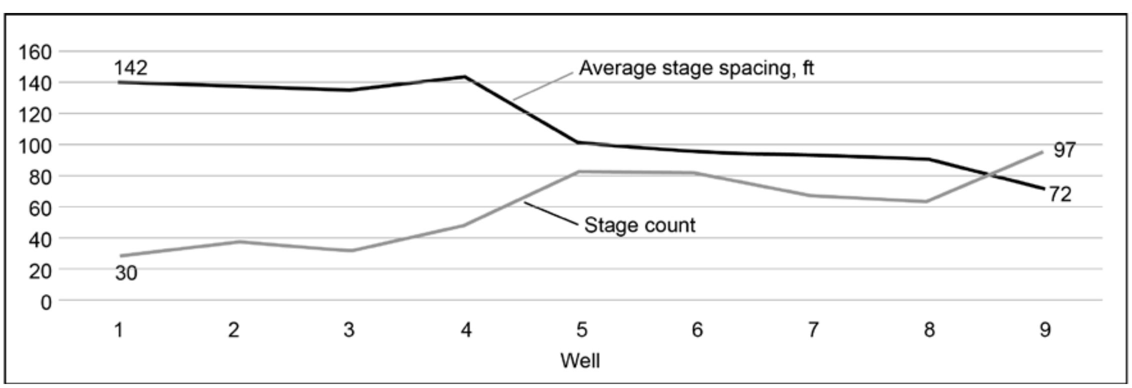

Figure 7. The combination of consistent frac placement and measured downhole data enabled the operator to accelerate the learning curve and optimize their completion design over nine wells, going from 30 stages per well to 97 and from 142-ft spacing to 72-ft spacing.