Pressure Data Analysis Guides Operators to Better Completion Decisions

A new physics-based method provides nonintrusive pressure data acquisition and analysis to develop accurate pressure-based fracture maps.

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As oil and gas operators continue to streamline operations in the office and the field, their reliance on data for uncovering efficiency levers is becoming permanent. The gold in the data is worth mining, so industry generally is looking at data and analytics in new ways to enhance decision-making about operations, sales, customer service and IT, for example.

Data can be statistics-based or physics-based. The statistics-based method, also known as Big Data analytics, is interesting for the oil field because the method offers insight into production performance. Operators are investigating this method to predict a new well's cumulative first-year production using a set of operational and completion characteristics such as lithology, well depth, stage length, fluid volume, proppant loading and cluster spacing.

A physics-based method includes fracture modeling and simulation of fluid flow in a network of induced and natural fracture systems coupled with geomechanics. Calibration of these models requires measurements of the fracture geometry created through hydraulic fracturing.

Acquiring fracture geometry for a meaningful number of wells has been challenging because the older methods of data acquisition are complicated, intrusive and expensive. Overall, this older technology disrupts field operations, requires additional wellsite personnel and equipment, and is expensive to deploy.

Fracture geometry also has been missing from statistical data analytics for these same reasons. Including fracture geometry as a variable for statistical data analytics would improve the predictability of these models by linking the geometry of the created fractures to completion parameters and production.

A new technology has been developed specifically to work around all of these challenges, enabling operators to have a full view of the fracture geometry on every well. The theory of this new, physics-based method is nonintrusive pressure data acquisition and analysis. The simple, accurate, affordable pressure-based fracture map—with fracture geometry of half-length, height, azimuth and asymmetry—is guiding operators to make informed, better completion decisions.

Pressure-based fracture map

This new oilfield diagnostic application—the integrated modeling approach for geometric evaluation of fractures or IMAGE Frac technology—is field proven in more than 3,500 hydraulic fracturing stages throughout the U.S. and in Canada. The technology is based on the poroelastic pressure response that occurs during normal hydraulic fracturing of treatment wells. The pressure response is recorded by a surface pressure gauge from one or more monitor stages in wells adjacent to the treatment well, or what is described as the monitor well. These wells can be interchangeable.

After acquiring the pressure data in the monitor stages, poroelastic pressure responses must be differentiated from pressure responses caused by direct fluid communication or advective/diffusive fluid transport. Once identified, poroelastic signals can be used to estimate hydraulic fracture geometry by matching the observed responses in the monitor stages to a digital twin. The output, which is the fracture map, is the fracture dimensions of half-length, height, asymmetry and azimuth and how fast those dimensions grew.

Case study

An operator working in the Eagle Ford wanted to evaluate completion effectiveness in the Lower Eagle Ford (LEF) shale formation and to identify an appropriate completion strategy in the field. The LEF's physical and geomechanical properties vary significantly from east to west of the formation. Local variations in thickness, thermal maturity and pore pressure pose several challenges in designing a suitable fracture job.

The operator conducted a study comprising 14 wells across multiple pads. Pressure-based fracture maps were acquired on all 14 wells. A test matrix was developed to evaluate various completion parameters: fluid system, stage length, perforation clusters, fluid volume and proppant volume. These parameters were varied across the 14 wells and spread across the test pads to ensure good geologic and geomechanical sampling.

The operator's goal was to evaluate the effect of stage length, number of perforation clusters, fluid systems, proppant loading and total fluid volumes on the resulting fracture geometry and production. With the pressure-based fracture map, the operator identified the right completion strategy and well spacing.

Increasing stage length. Historically, the operator had used a 200-ft stage length with six clusters per stage. Based on the right completion strategy from the pressure-based fracture map, the operator made the informed, better decision to increase the stage length 50 ft to 250 ft with nine clusters per stage. The fluid and proppant volumes were adjusted to provide the same fluid and proppant per cluster. Three fluid systems were evaluated: the company's standard historical design, slickwater and a hybrid cross-linked gel system.

Reveal Energy Services' geoscientists and completion engineers computed fracture maps for all 14 wells and analyzed them to understand the importance of each completion parameter on the resulting fracture geometry.

Figure 1 shows the effect of changing the stage length from 200 ft to 250 ft for various fluid systems. The results show that the new design with longer stage length and nine clusters provided the same geometry, measured by fracture half-length, as the historical completion design for all three fluid systems. This resulted in a 20% reduction in the number of stages without compromising the effectiveness of the stimulation.

Fluid volumes. Three different fluid volumes were evaluated to determine the optimal fluid loading: 25 bbl/ft, 32 bbl/ft and 40 bbl/ft.

Figure 2 shows the results. Stages with 25 bbl/ft and 32 bbl/ft showed similar fracture half-lengths. Increasing the volume from 32 bbl/ft to 40 bbl/ft, a 25% increase, had a significant change in the resulting half-length. Half-lengths were 33% longer with the 25% increase in fluid volume.

Using these results, the operator was able to decide on various completion design parameters for field development. The results were derived from the physics-based model of nonintrusive pressure data acquisition and analysis that offered

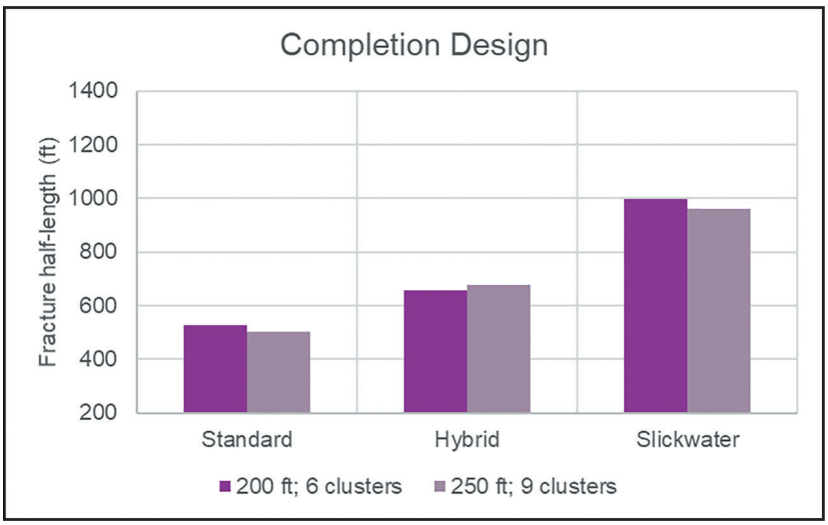

FIGURE 1. By deciding on a 250-ft stage length for these fluid systems, based on the pressure-based fracture map, an Eagle Ford operator achieved the same fracture half-length as the historical 200-ft completion design. *(Source: Reveal Energy Services)*

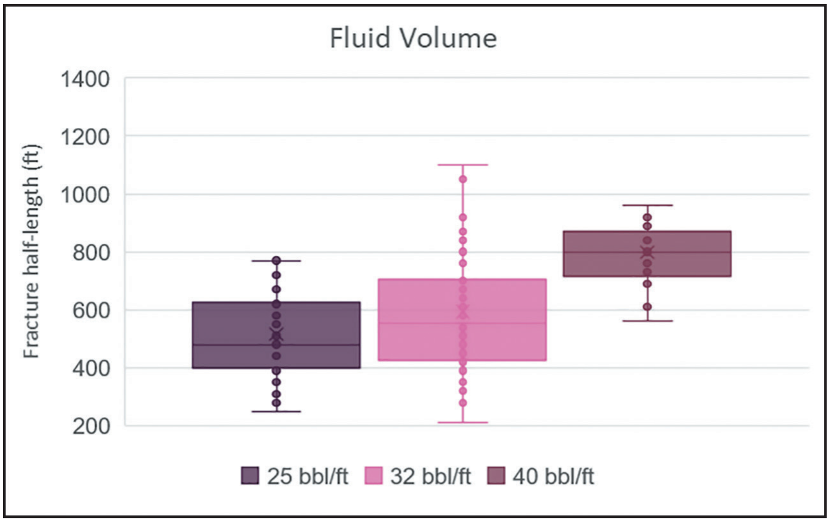

FIGURE 2. An Eagle Ford operator increased fracture half-lengths 33% with a 25% increase in fluid volume. *(Source: Reveal Energy Services)*

more reliable, confidence-building measurements compared with the conventional methods.

As additional confirmation of the validity of this physics-based approach with the new fracture map technology, the operator's team compared all of the completion results with the production data. The production data confirmed the conclusions from the pressure-based fracture map analysis.

The pressure-based fracture map offers the industry a new diagnostic means to validate a completion design on every well with minimum operational risk and cost. The simple, accurate, affordable pressure-based fracture map enables operators, as described in this case study, to make informed, better completion decisions. ■