Originally appeared in World Oil® MARCH 2019 issue, pg 61-64. Used with permission.

Optimizing STACK diversion strategy using pressure-based fracture maps

Fracture mapping enables operators to determine the effectiveness of different diversion techniques to control fracture growth and minimize inter-well communications.

JEFF KOPP, CHARLES KAHN and ERICA COENEN, Reveal Energy Services; CHARLES ALLEN, JAKE HUCHTON and CLARK ROBINSON, Chaparral Energy

Achieving an effective completion of a hydraulically fractured well, and ensuring optimal reservoir contact, requires analysis of the perforation cluster location, perforation intervals, and the total number of clusters. Multiple clusters are designed within a single stage, so a given stimulation treatment can cover a long interval without compromising the operational efficiency and access to the reservoir.

Variations in stress and heterogeneity affect the geomechanical properties along the stage length, which can result in non-uniform fluid distribution across the clusters, limiting the fracture growth from each cluster. The lower stress clusters will initially take most of the fluid and proppant, leading to large variance in the number and geometry of fractures created in a stage. This interaction means typically that 30% to 40% of perforations do not contribute to production in a multi-stage fracture stimulated well, and the majority of production comes from only 20% to 30% of the clusters.

Diversion material, which typically consists of some combination of chemicals, fibers and particles that act to create a temporary plug, is used to divert fluid from one cluster to another, improving the cluster efficiency, and the number and geometry of fractures created in a given stage.

Typical diversion design includes the amount of diverter material, the timing of the diverter drop, as well as number of drops required within a given stage. Recent experiences also have shown the successful application of "sand ramps"—where no changes are made to the pumping rate, while introducing multiple proppant ramp cycles throughout the treatment duration.

The key challenges, then, for the completion engineer are: 1) identifying diversion designs needed to test; and 2) evaluate the effectiveness of the individual diversion design on single stages. Near real-time analysis of diversion becomes necessary to make changes on the spot, which has been challenging with most diagnostics.

OFFSET WELL PLOT

The operator selected three horizontal Meramec wells in the STACK field for this case study. The STACK area, in Oklahoma, has several producing horizons, enabling operators to target multiple layers and provide excellent cost-efficiencies.

The purpose of this study was to engineer a diversion strategy from differing techniques to determine the most effective diversion on a per-stage basis (Fig. 1), while also testing the completion sequence to control fracture height growth. The base design for these treatments was to use three sand ramps, comprising 100 mesh and 40/70 mesh for each ramp. To validate the results statistically, adequate sample sizes were necessary for comparison of each diversion design.

Sand ramps. Well 1H was set up as a control group. The basic treatment design was applied to all stages on Well 1H without any diversion to provide a baseline.

Four pods/ramp. Applied as single drops for two stages, and double drops for 14 stages, across wells 2H and 3H.

Six pods/ramp. Applied as single drops for two stages, and double drops for 21 stages, across wells 2H and 3H.

Eight pods/ramp. Applied as only double drops for two stages across well 3H.

Evaluating effectiveness of diversion has typically relied on two legacy diagnostic methods: 1) using treatment pressure analysis looking for surface pressure changes associated with the diverter drop; and 2) chemical or radioactive tracers before and after a diverter drop.

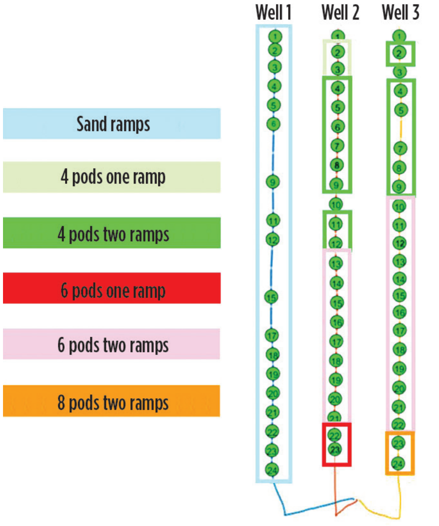


Fig. 1. Pad layout and diverter program design.

Using treatment pressure often provides false positives—where a surface pressure increase indicates a successful diversion. In this case, the diverter has not plugged the dominant cluster, but plugged the non-dominant cluster, giving a positive surface pressure reading, recorded as a successful diversion. Using treating pressure has not proven to be a reliable method to determine diversion effectiveness. Chemical tracers have been used to understand the changes in inter-well communication, and thus assess the success or failure of diversion. Tracer evaluation can be time-consuming, requiring sampling and analysis of produced fluids.

OFFSET PRESSURE MONITORING

After acquiring the pressure data in the monitor stages, poroelastic pressure responses must be differentiated from pressure responses caused by direct fluid communication or diffusive fluid transport. Once identified, poroelastic signals can be

Fig. 2. Data acquisition for pressure-based fracture maps.

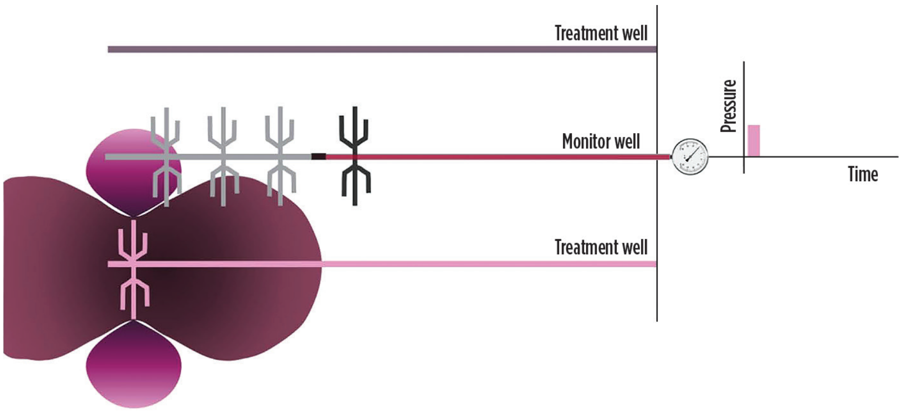
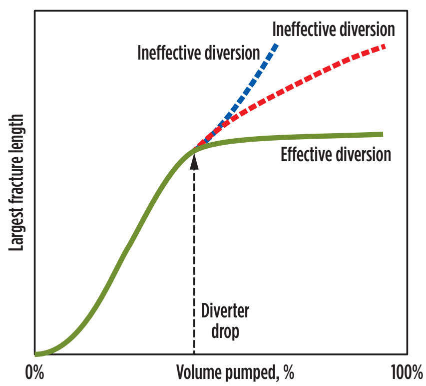


Fig. 3. Use of fracture growth rate to evaluate diverter effectiveness.



used to estimate hydraulic fracture geometry by matching the observed responses in the monitor stages to a digital twin. The results of the analysis are applied to:

- Quantify 3D fracture maps of half-length, height and asymmetry.
- Understand whether a diversion technique is working.
- Recognize if the fluid is distributed between multiple clusters.
- Identify the depletion boundary surrounding a parent well.
- Determine how far proppant has been placed within the fracture.

The low cost, accuracy, and ease of deployment means this technology can be applied on every well to enable fracture diagnostics and quality control of completion design performance. By providing near real-time assessments of completion performances, it allows operators to adapt the completion design to geological variations and changes in stress profile along the lateral. The pressure data can be processed quickly to inform decisions, mid-completion.

This rapid feedback allows operators to test multiple completion ideas and focus on the one that is most effective. An operator interested in evaluating diversion techniques might deploy one in the first four stages, then modify the technique or switch to another based on the feedback from pressure-based fracture maps. By the end of the pad, the operator will be able to evaluate several diversion materials and techniques and identify the combination that gave the best results.

DATA ACQUISITION

To apply this technique, offset pressure data must be acquired, using a specific process in the field, Fig. 2. Pressure measurements must be taken from one or more monitor stages, in one or more monitor wells, adjacent to a well undergoing stimulation. A monitor stage is established by isolating it from previous stages along the lateral, ordinarily with a solid bridge plug or a controllable frac sleeve.

This is done to ensure that the pressure signal being measured in the monitor well is entering the wellbore from a precise, known stage location. After isolation, monitor stage(s) must be completed normally with an incompressible fluid column established to the surface. Monitoring may then begin, measuring the pressure response in a single isolated stage in the monitor well.

To ensure that enough data are collected to resolve fracture geometries, multiple treatment stages should be completed and observed from each monitor stage. This provides the necessary constraints to determine unique fracture geometries for the observed treatment stages and the monitor stage.

After acquiring the pressure data in the monitor stages, poroelastic pressure responses must be differentiated from pressure responses caused by direct fluid communication or diffusive fluid transport. The process for identifying and quantifying poroelastically induced pressure responses relies on quantitative measurement of pressure signal arrival times, magnitudes, derivatives and durations. Once identified, poroelastic signals are used to estimate hydraulic fracture geometry by matching the observed responses in monitor stages to a digital twin.

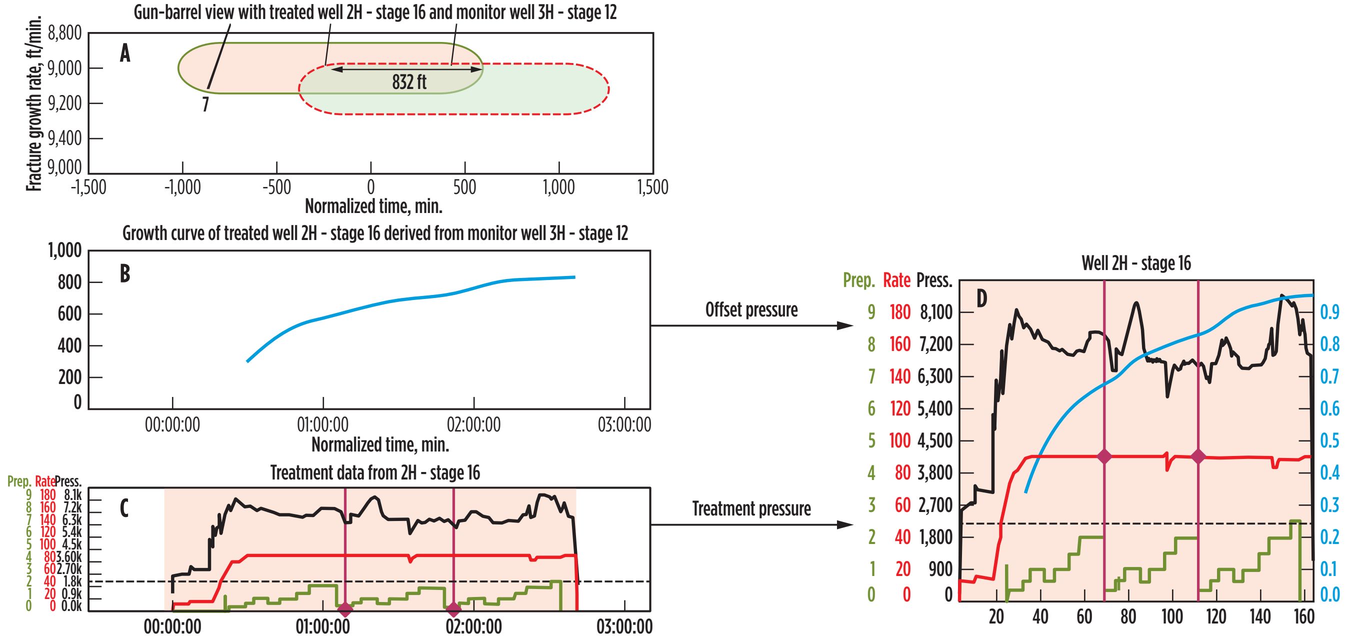
DIVERTER EFFECTIVENESS

The ability to determine diverter effectiveness quickly, cost-effectively, as well as being operationally non-invasive, has been troublesome. However, a unique approach that represents a significant change in evaluating diversion effectiveness has been developed, using offset pressure measurements, enabling a process to help design a completion strategy to fully stimulate each stage, enhance cluster efficiency, and improve fluid distribution across the stage. The knowledge of diverter effectiveness provided by this approach leads to a better understanding of the diversion process and enable near real-time optimization, where the results of a diverter stage are used to adjust treatment design for subsequent stages.

Once the fracture geometries have been resolved, diversion effectiveness may be evaluated by observing the growth of the largest fracture, before and after a diverter drop in each stage. Diversion effectiveness is quantified using these fracture growth patterns, which are classified into four categories: 1) successful in stopping dominant fracture growth; 2) impeding the dominant fracture growth; 3) diversion having no impact; and 4) adverse effects of diversion in accelerating dominant fracture growth.

Successful diversion results in plugging the dominant cluster, stopping the growth of the dominant fracture and forcing fluid into the remaining clusters in the stage. This results in improved fluid distribution and improved cluster efficiency in that stage. In the case of successful diversion, the growth rate of the dominant fracture stops post diversion, Fig. 3. Ineffective diversion results in the dominant cluster continuing to take fluid after the diverter drop, resulting in continued growth of the dominant fracture. Occasionally, the growth rate of the dominant fracture is seen accelerating

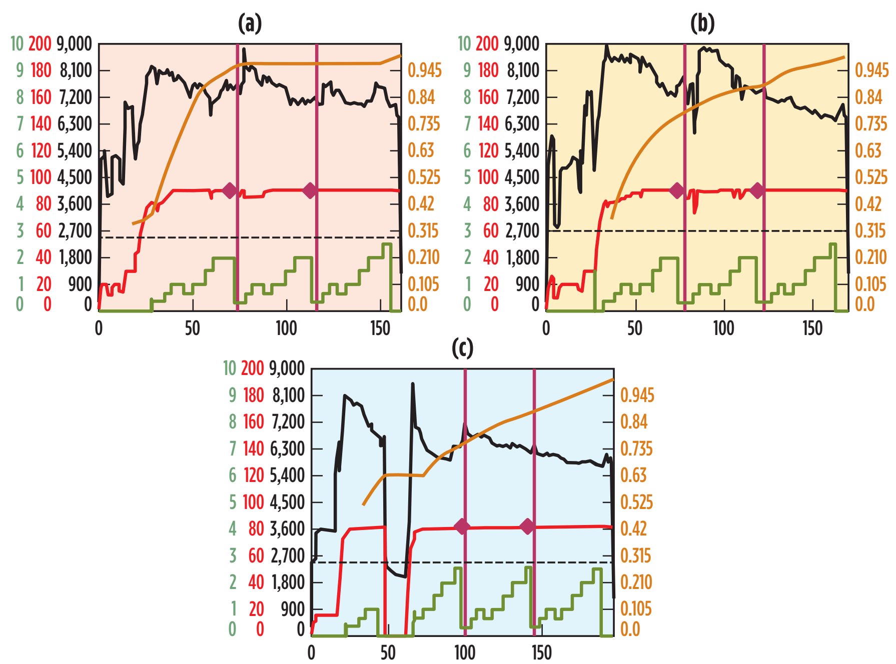
Fig. 4. Offset pressure monitoring diversion evaluation.



after the diverter drop. This indicates that the diverter has plugged a non-dominant cluster, forcing even more fluid into the dominant cluster, accelerating growth of that dominant fracture, certainly not a desirable outcome.

This analysis was applied for all the monitored stages on the 3-well pad. Diverter effectiveness was evaluated for the four diversion designs implemented on this pad.

Fig. 5. Diverter performance classification.



TRACER DATA ANALYSIS

Fluid tracing involves pumping unique, water-based tracers in the pad and in the proppant-laden fluid of each stimulated stage. After fracturing operations are completed, water samples from the flow-back stream are caught and analyzed with gas chromatography/mass spectrometer, and the data are presented in a digitally formatted report. Concentrations of the recovered tracer in parts per billion of each individual fluid tracer, at various flow-back volumes and elapsed times, are recorded and used for inter-well communication analysis.

In this study, chemical tracers were selected to provide an understanding of inter-well communication, and a qualitative measure of the diverter effectiveness. Effective diversion was expected to reduce the degree of inter-well communication. Due to the limitation on the number of unique tracers that can be applied, chemical tracers for the oil and water phases were added to the fracturing fluid injected in groups of eight: three stages per group on each well, with the primary goal of understanding inter-well communication. In total, 24 unique oil/water tracers were used in this study.

Production samples were collected for 30 days and analyzed for concentrations of the various tracer for each stage grouping in the injected and the offset wells. The pumping schedules consisted of two to three proppant ramps/stage. Diverter was dropped at the end of the first and/or the second proppant ramp of each stage. Engineers analyzed the cumulative amount of water and oil tracer recovered at the end of a 30-day sampling program for each well.

The results suggest that both timing and quantity of diverter play an important role in creating effective diversion and increasing number of diverter pods achieved better diversion, along with re-

Fig. 6. Comparison of diverter effectiveness for sand ramps.

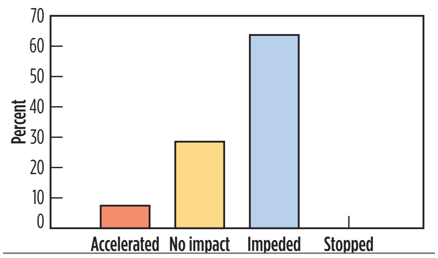


Fig. 7. Fracture growth rates as a function of number of pods.

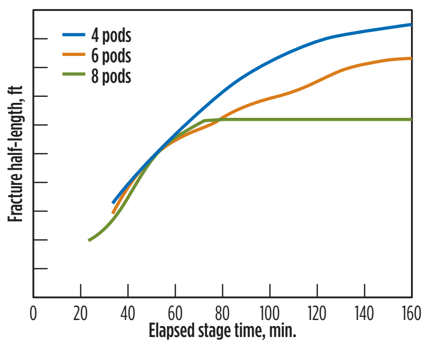
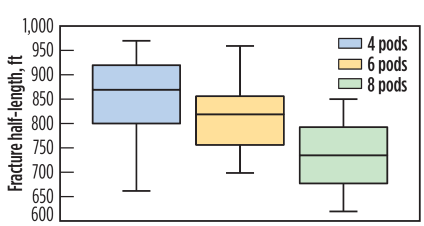


Fig. 8. Fracture geometry comparison for three diverter designs.



duced inter-well communication. Overall, well 1H showed the most connectivity with the other wells, which may have been caused by lack of diversion used on the well. Well 2H was completed prior to treating the other wells and showed similar amount of water tracer from both the other wells consistently along the lateral.

However, the oil tracers decreased toward the heel stages of the well, where more pod diversion was applied. Well 3H showed connectivity with Well 1H in the heel stages with oil and water tracers, this indicated that the order of operations and frac azimuth play a role in well connectivity.

FRACTURE MAP ANALYSIS

As described earlier, offset pressure data were used to compute the fracture geometry, as well as the growth rates of the largest fractures in a given stage. Comparing the fracture growth rates, pre- and post-diversion, allows accurate determination of diverter effectiveness, Fig. 4. After the fracture geometries have been resolved, the rate at which the fracture grew to reach the final geometry can be determined by walking back the pressure signal. Panel B is the growth curve developed from pressure-based fracture maps. Panel C represents the treatment data from the treated well, with black representing the treatment pressure, red representing the treatment rate, and green representing the proppant concentration. The pink polygons represent diverter being dropped at surface and the pink lines represent diverter hitting the perfs.

Once the growth curve from Panel B is combined with the treatment information from Panel C, the growth curve can be compared easily to completion strategy changes. Panel D is the combination of the two, with growth curve changes being easily identifiable against the diversion hitting perfs.

Figure 5 shows examples of effective and in-effective diversion, as seen on some of the stages of this pad. Figure 5a is an example of successful diversion, indicated by the growth of the largest fracture being stopped immediately after diverter pods reach the perforation clusters. In this example, we can observe clearly that the largest fracture stopped growing after the first diverter reached the perf clusters. Figure 5b indicates that the diverter was partially effective in impeding the dominant fracture growth, since fracture growth rate after the diverter drop is reduced, but not completely stopped. Figure 5c indicates in-effective diversion, as the fracture continues to grow at the same rate, post-diversion.

Using the analysis, we can look at changes in diverter effectiveness for the three diverter designs. Figure 6 summarizes the results of stages from well 1, where only sand ramps were used without any pods for diversion. None of the observed stages showed fully effective diversion, where the growth of the dominant fracture was stopped. And, 62% of the stages treated with sand ramps showed that the growth range of the dominant fracture was impeded, when the mesh size within a given proppant ramp was changed from 100 mesh to 40/70 mesh, while 30% of the stages showed no change in the growth rate of the dominant fracture.

About 8% of the stages showed an acceleration of the dominant fracture associated with changing the mesh size in a given proppant ramp. Using sand ramps, without the addition of pods, provided limited success in achieving diversion. The results also showed significant variation between stages, making this technique unreliable to achieve consistent diversion.

Figure 7 shows a comparison of the fracture growth rates of the dominant fracture and thus the diverter effectiveness for the various number of pods used. Increasing the number of pods showed a significant decrease in the growth rates of the largest fracture. Increasing pods from four to six showed a moderate change in the growth rate, suggesting a moderate improvement in diverter effectiveness for the six pods compared to the four pods. Increasing the number of pods to eight showed a significant improvement in diverter effectiveness. The growth of the largest fracture was completely stopped, as soon as the eight pods reached the perforation clusters.

To obtain a meaningful analysis of the diverter effectiveness, it is necessary to look at the results from multiple stages treated with similar designs. This will account for changes in rock properties along the lateral and impact of stress shadowing from the fracturing sequence. Figure 8 shows the fracture geometry comparison for all stages monitored with a given diverter design. Significant reduction is observed in the measured fracture half-length, when the number of pods was increased from four to six to eight.

CONCLUSION

Results from the pressure-based fracture maps indicate successful diversion on 72% of stages analyzed.

Results also gave conclusive evidence that increasing the number of pods from four to eight provided a significant reduction in the overall fracture half-length, thus minimizing interwell communications.

The results from pressure-based fracture maps were consistent with those from water and oil tracer analysis. The offset pressure analysis provided a more robust, rigorous analysis of diverter effectiveness, enabling the operator to accurately assess the success of diversion on a stage-by-stage basis. WO

ACKNOWLEDGEMENT

This article was derived from SPE paper 194330, which was presented at the SPE Hydraulic Fracturing Technology Conference, held in The Woodlands, Texas, Feb. 5–7, 2019.