Approach Optimizes Frac Treatments

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HOUSTON—Geologic, well log, surface seismic and microseismic data were integrated using advanced reservoir modeling software to enable real-time completion optimization of multiple laterals drilled from the same well pad in a Barnett Shale project.

The laterals are spaced as close as a few hundred feet laterally with varying vertical landing points. Although the laterals expose more of the nanoDarcy-permeability shale rock and increase contact area through fracture stimulation (resulting in more efficient drainage), the challenge is optimizing stimulation treatments to maximize coverage around each lateral. The optimization process involved perforating and stage placement, sequential stimulation of the laterals, fluid and proppant schedules, treatment rates, and applying diversion technology when appropriate to achieve effective stimulation along the laterals and between the wells.

Opportunities to make changes to original designs were seized when injectivity problems were encountered early in the treatment process. This approach was executed successfully to gain injectivity and increase the conductive fracture area, allowing fracs to be managed in real time.

Observed fracture pressure responses and production from the pad wells validates the approach. Ultimately, an optimal horizontal stimulation was achieved by leveraging favorable rock properties to create a larger fracture surface contact area, thereby maximizing gas production potential and recovery.

In addition to drilling longer laterals to increase coverage per well bore, drilling multiple laterals from the same pad greatly reduces the surface footprint by minimizing the number of surface locations needed while increasing downhole contact with the shale. Several fracturing schemes have been developed to hydraulically stimulate pad wells, including sequential (zipper) fracturing in which wells are stimulated in pairs.

In the Barnett application, the individual wellheads are relatively close to one another, allowing the entire operation to be completed using one stimulation and perforation crew. On any given pair of wells on the same pad, while one well is being fracture stimulated, the crew is setting plugs and perforating the next stage in the other well bore. This process continues back and forth between the crews until all stages in both wells are stimulated from toe to heel.

The desired end result is hydraulic fracture stimulation of multiple shale gas wells drilled from the same pad in an operationally efficient fashion, but there is also a potential derivative benefit of the zipper frac technique: When the second well is being stimulated, the net pressure created by the stimulation stage on the

FIGURE 1
Horizontal Wells on Single Pad with Integrated Seismic, Well Top, Horizon and Well Log Data
adjacent first well can help divert the fracture direction and increase complexity development in successive fracturing stages, thereby increasing the effective stimulated volume.

**Multidisciplinary Information**

The multidisciplinary information required to make real-time decisions during hydraulic fracture treatments includes a velocity model that is representative of the area, which requires a vertical seismic profile, check shot or a sonic log from an offset well. The velocity model is critical to depth converting the seismic data used to display relevant seismic attributes such as curvature and proximity to geohazards. Depth-converted data must be checked with other sources of information, such as geosteering and well top information, to ensure consistency.

Horizons, well top picks and other well data to be incorporated in the visualization model are also crucial. This information is used in making real-time decisions during hydraulic fracturing, guided by microseismic data analysis. All available log data, especially sonic-derived mechanical properties mapped along the lateral, are useful in understanding the correlations between log-scale and seismic-scale information.

Figure 1 is a simplistic view of this concept showing seismic, well top, horizon and well log information captured around the four horizontal wells. Typically, the challenges are associated with acquiring the right set of information, validating the model and interpretations, and integrating this multidisciplinary information under a common platform before the stimulation treatment. Once this process is completed, as was the case with this project, the resulting product is extremely useful in optimizing the stimulation treatment.

The four Barnett wells (Figure 2) were drilled parallel to one another on the same pad and completed with 5½-inch N-80, 17 pounds/foot casing. All the well bores are directed in the direction of minimum horizontal stress (northwest-to-southeast) to generate multiple transverse hydraulic fractures. The well bores are spaced a few hundred feet apart laterally and range in total vertical depth between 6,500 and 6,800 feet.

Figure 2 also shows the closure stress or fracture gradient derived from sonic logs for Well No. 2, which accounts for mechanical properties anisotropy that is common in organic shales. The red and blue colors indicate lower and higher closure stress values, respectively, with white representing a middle closure stress value range. Closure stress values are used to place perforations at the lowest stress.

The four wells were stimulated in pairs, starting with wells 3 and 2 and then moving to wells 1 and 4. Microseismic data were acquired using a dual-monitoring configuration with one set of geophones placed along the lateral section (monitor Well No. 1 in Figure 2) and the other set in the vertical section of either Well No. 4 (while stimulating wells 2
and 3) or Well No. 3 (while stimulating wells 1 and 4). The backdrop is seismic curvature from the Ordovician, with green indicating negative curvature and brown indicating positive curvature.

**Lateral Landing, Perforation**

Placing the lateral in the “sweet spot” of the formation is important in all shale plays. The sweet spot is best defined by both reservoir quality—identified by properties such as total and free gas porosity, total organic content, clay volume, fluid saturations, effective porosity and permeability—as well as completion quality as it relates to the geomechanical properties of the rock. Devon has performed extensive fieldwide reservoir quality log and core measurements to map the quality of the reservoir vertically and laterally.

A series of downhole injection stress testing measurements also was performed across the field using a specialized wireline tool to calibrate the sonic log to the measured in situ stress for the Barnett and intervals both above and below it. This information was invaluable in understanding completion quality issues such as hydraulic fracture growth and containment, especially when there is a need to avoid water zones above or below the target reservoir.

Figure 3 shows an output incorporating both reservoir and completion quality from a pilot hole drilled northeast of the four-well pad. This information was used to select the lateral landing points of the horizontal wells, with the wells staggered vertically and laterally to maximize contact across the entire area. The only lateral that was landed above the zone of interest presented distinct challenges during stimulation.

An advanced cased-hole sonic log capable of accounting for the anisotropic mechanical properties in shales was run on Well No. 2. When combined with neutron-density and spectral gamma ray logs, this information can be used to derive the lithology of the formation to allow perforations to be placed in the low-stress, good reservoir-quality rock. Staging length and perforation spacing were based on a combination of parameters, such as proximity to seismic curvature, local stress and gas shows obtained from mud logs to ensure that these spots were covered by perforations and well bore deviation angle limit for the heel-most perforation cluster.

Once the perforation and staging design were completed for one lateral, the perforation scheme for successive laterals was based on a staggered design with respect to adjacent wells (both laterally and vertically) in the same pad, along with incorporating hydraulic fracture orientation and fairway width from offset wells to enable maximum hydraulic fracture coverage in the zones of interest. This was further validated using real-time microseismic data during the stimulation treatment to ensure adequate coverage.

**Flow Diversion**

Although several flow diversion techniques exist for stimulating with multiple perforation clusters, it is not always easy to divert fluid flow in the fracture after pumping several thousand barrels into the formation. Fiber diversion systems have been used successfully in the Barnett Shale to effectively bridge fractures and divert fracture fluid flow into a new, previously unstimulated section of the reservoir in both new wells and recompletions. Fibers also have been used to contain hydraulic fracture height growth.

The diversion slurry contains a fiber-based degradable diverting agent that bridges over the path of an existing or growing fracture system and generates a pressure increase sufficient to initiate and propagate a fracture in new reservoir sections. The technology is effective when used with real-time microseismic data analysis to formulate the composition and placement of the diverting slurry according to observed fracture parameters. In some cases, the process can be iterative in nature by using the feedback received from post-diversion microseismic to fine-tune the parameters for successive diversion slugs.

Microseismic data were acquired, interpreted and presented in real-time along with the pumping data on a visualization platform along with geologic and reservoir information for every stimulation stage. This approach brought a multidisciplinary team together during the stimulation job to make collaborative decisions to achieve maximum coverage around the stage being stimulated, while avoiding unwanted height growth away from the zone of interest.

During the fourth stage on Well No. 3, the job stimulation initially pumped 100-mesh sand according to the design for more than an hour. At that point, the microseismic activity was clearly showing a downward trend growing past the top of the Ellenberger.

While in the initial stages of the job and still needing to pump the rest of the 100-mesh and more conductive coarser sand, it was decided to deploy fiber di-
version slugs in an attempt to control the downward height growth and allow the job to be pumped to completion. Operational procedures were followed carefully to ensure smooth surface and downhole delivery of the diversion package.

The job rate and proppant schedule were restored after deploying the fiber package, and treatment pressure and microseismic activity were monitored to observe the effect of diversion. The microseismic activity post-diversion is indicated by the blue spheres on Figure 4. The period over which this activity occurred is shown in the blue-shaded area on the pumping window.

After introducing the fiber diversion package, almost no downward fracture growth was observed for more than an hour, indicating that the system effectively bridged the far-field fractures, creating a local net pressure, diverting fracture fluid and proppant flow into unstimulated sections of the lower Barnett, maximizing in-zone stimulation energy and increasing the fracture contact area. The pressure response showed a maximum increase of about 1,000 psi after diversion, indicating the bridging effect of the fibers. The smaller mesh sand was brought back on schedule once the higher pressure stabilized.

**Real-Time Management**

When multiple laterals are drilled close to one another and stimulated sequentially in a pad drilling scenario, fracture coverage is expected to be unpredictable because of induced stress from the previous fracture or adjacent lateral. The real-time information was used to make effective decisions and optimize coverage around the designated lateral for each of the stages.

For example, microseismic data while pumping one stage on Well No. 3 showed that hydraulic fractures were predominantly growing to the northeast of the well bore in an area designed to be covered by stimulation treatments in another well on the pad. Consequently, the fracture coverage was altered using the fiber diversion package to create local net pressure in the far-field region of the fracture system.

The fiber diversion increased surface pressure by 400 psi and the microseismic data indicated effective diversion of the fracture growth from northeast to southwest of the well bore, closer to the perforations designated for the stage, as shown in Figure 5, where red and cyan spheres indicate pre- and post-diversion microseismic activity. This was very beneficial at this stage of the job as the tail-in proppant was scheduled to be pumped. This diversion enabled this high-conductivity proppant to be placed in the near-well-bore region, which is subjected to the largest pressure drop during production.

Another example comes from Well No. 4, which was landed above the zone of interest. The breakdown and average treatment pressures on this well were quite different from the other three laterals on the pad. While treatment pressures ranged between 3,000 and 3,500 psi at an average pump rate of 60 barrels/minute on the other wells, treatment pressure on Well No. 4 averaged in the 5,000 psi range at the same average rate.

The well exhibited consistently higher initial breakdown pressures and continued to exhibit higher pressures for the first hour of each stage. While treating some stages on the well, multiple acid slugs had to be pumped to break down the formation and establish the desired pump rate. When microseismic activity indicated that fracture coverage was growing toward the lower-stressed bottom zones, treatment pressures stabilized at lower values. This allowed higher proppant concentrations to be pumped toward the tail end of the treatment.

In addition, a clear correlation existed between the lateral landing intervals and the observed treatment pressures during the stimulation treatment, further emphasizing the value of landing the lateral in the best completion and reservoir-quality rock.

Real-time microseismic data enabled the team to verify coverage versus corresponding treatment pressure responses, which allowed real-time modifications of proppant volumes, ramp schedules and other parameters to increase near-well bore conductivity and connectivity to the lower Barnett.

Throughout the entire sequence of stimulation stages, observed microseismic fracture coverage and orientation from previous stages were used to optimize staging and perforation designs. The original design on Well No. 1 included six fracture stages. After the fourth stage was pumped, the observed microseismic activity clearly indicated overlap with the area designated to be covered by the fifth stage. This led to eliminating the planned sixth stage and redesigning the fifth-stage perforations (shown by blue disks in Figure 6A). This maximized fracture coverage along the lateral and minimized stimulation overlap, while reducing the number of stimulation stages and corresponding cost.

Figure 6B shows the microseismic coverage from the revised fifth treatment stage, with stimulation coverage in the previously unstimulated portion of the reservoir. The ability to optimize staging and perforation design in real time enables
cost savings by eliminating stages when appropriate, and more importantly, ensuring that decisions are made to maximize the effective stimulation volume throughout the field.

Production Performance

Comparing the production performance of multiple laterals drilled from the same pad is somewhat skewed since all the well bores are stimulated and produced at the same time. Nevertheless, a normalized approach to a production comparison incorporating relevant parameters such as lateral length, lateral landing interval with respect to the sweet spot, stimulation job volumes, and number of stimulation stages yields a meaningful analysis. In the case of the four Barnett wells, stimulation job parameters were normalized based on both a fluid completion index (FCI) and a proppant completion index (PCI), with higher values corresponding to more stimulation energy (therefore, more cost).

Wells No. 1 and No. 3 were landed closest to the best rock quality, with Well No. 2 slightly above the sweet spot and Well No. 4 above the zone of interest. Well No. 4 has the longest lateral and highest FCI and PCI of all four wells, but less normalized production in terms of million cubic feet of gas per foot of lateral and 12-month cumulative production than Well No. 3 (with a 22 percent shorter lateral). Well 4 also has the lowest initial production.

Despite having a 40 percent lower

**FIGURE 6A**
Modified Stage Five Design to Minimize Stimulation Overlap (Well No. 1)

**FIGURE 6B**
Microseismic Coverage During Stages Five (Green) and Four (Yellow)
FCI and a 27 percent lower PCI, Well No. 1 has almost the same 12-month cumulative and normalized production as Well No. 2. The IP rates from the two wells also are comparable, confirming that eliminating the stimulation stage based on real-time microseismic data resulted in lower stimulation cost without compromising performance.

If the lateral is landed in the right interval, one would expect an increase in cumulative production at any given point without compromising the normalized performance. This was, in fact, the case with Well No. 3, which showed not only the best IP, but also had the highest one-year cumulative production.

Integrating seismic, geology and log data in a visualization platform, combined with real-time microseismic monitoring for effective decision making during stimulation and fiber diversion, enabled fracturing operations to be managed in an optimal fashion and surprises to be dealt with in an effective way. This allowed staging and perforation designs to be modified based on real-time information to optimize treatment effectiveness and increase contact area during stimulation.