Fracs tracked using microseismic images

Frac imaging shows the need for improved frac diagnostics and control, and the means for achieving it.

AUTHORS

S.C. Maxwell *and* ***T.I. Urbancic****, ESG International, Kingston, Ontario, Canada.* ***N. Steinsberger****, Devon Energy, Fort Worth, Texas and* ***R. Zinno****, Schlumberger, Houston, Texas.*

Real-time microseismic imaging was used to map hydraulic fracture growth in the naturally fractured Barnett Shale in the Fort Worth basin in Texas. Modified earthquake seismology techniques have yielded images that clearly illustrate the fracture complexity and variability that develops during hydraulic fracture stimulations in naturally fractured reservoirs. While several diagnostic techniques exist, microseismic imaging offers the best resolution for imaging fracture complexity. The resulting images hold promise for optimizing well drainage and identifying locations of bypassed reserves. Incorporating real-time microseismic images into the stimulation operation also assists in the optimization of hydraulic fracture completion designs.

Selecting a Study Field

Hydraulic fracture geometries are difficult to predict. Even in environments with relatively simple fracture geometries, hydraulic fractures can grow asymmetrically, have variable confinement across geologic horizons, and change orientation. In naturally fractured reservoirs, such as the Barnett Shale, hydraulically created fracture patterns become amazingly complex as the injected slurry preferentially opens the pre-existing fracture network.

Devon Energy's East Newark field in the Fort Worth basin field produces from Mississippian shale (Barnett) lying between the Viola and Marble Falls limestones. The shale varies from 300 ft to 1,000 ft (91.5 m to 305 m) thick, is extremely low permeability (± 0.0001 millidarcies), and contains a network of natural fractures. Large-scale hydraulic fracturing is used to stimulate production to economic levels and wells are infilled on spacing as tight as 27 acres.

Microseismic imaging was chosen to define fracture geometry and growth characteristics during stimulation.

The results, which demonstrated the substantial fracture complexity that occurs and its relationship to final well production, led to concrete plans for optimizing field management.

Getting Started

Microseismic imaging of hydraulic fracturing relies on the detection of microearthquakes, or acoustic emissions associated with either fracture creation or the induced movement of pre-existing fractures. Data acquisition is accomplished with a long, 650 ft (198 m), multilevel geophone array deployed via wireline in a temporarily offline production well (observation well) less than 1,600 ft (488 m) away from the well being fraced.

Once the process is initiated, the continuous acoustic signals acquired are fed into the FRACMAP microseismic imaging software, which archives and automatically processes the detected microseismic events for 3-D event locations, location errors, magnitudes and other seismic source attributes. When desired, the results are rapidly transmitted to the frac van and used "on the fly" to image the frac and change the injection parameters to gain optimum fracture characteristics. Images are also used for post-frac analysis such as calibrating numerical simulations, predicting drainage patterns, assessing frac design changes and optimizing frac design.

Initial Images

The time-lapse nature of Figure 1 (top to bottom) shows that the seismicity migrated out from the treatment well in a broadly expanding network of lineations covering a nearly square area. This is in sharp contrast to what is normally expected — fractures growing in a single vertical plane within a narrow drainage area. In depth, the events are located within the Barnett Shale, which confirmed that the fractures were better contained within the target zone than previously thought.

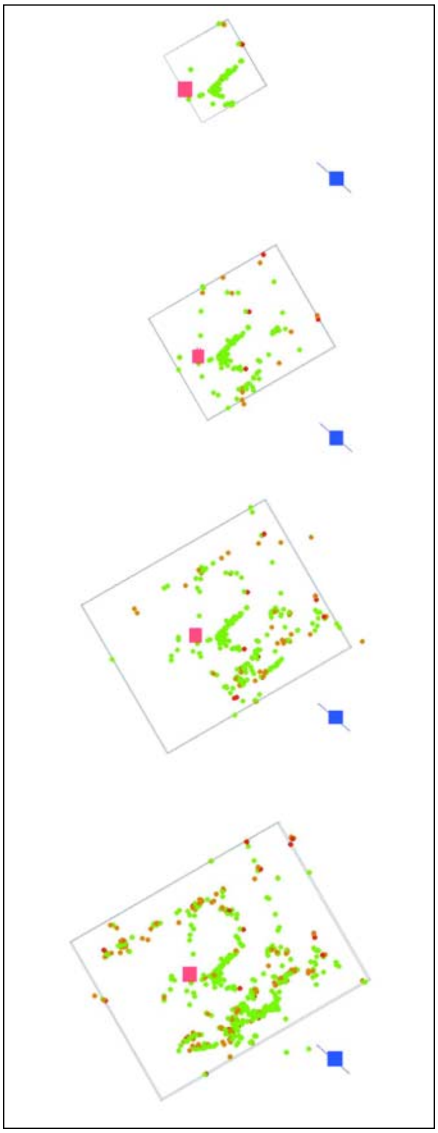

Figure 1. A microseismic imaging array placed in an observation well (blue square) recorded events caused by hydraulic fracturing as the frac fluid moved away from the treatment well (red square). Snapshot images over time at 80 min., 130 min., 190 min. and end of frac, are shown top to bottom. In this plan view image, events of highest magnitude are shown in red.

The Figure 1 sequence, resulting from a 56 bbl/min, 6-hour water frac, shows microseismic events that, in plan view, are distributed over three main parallel lineations trending Northeast-Southwest (NE-SW) and parallel to the anticipated frac orientation at a spacing of roughly 300 ft (91 m). A number of less extensive, nearly perpendicular lineations also are present in this image within the three main NE-SW features. It was thought that the lineations formed when the frac slurry opened and connected the reservoir's natural conjugate joint system following a tortuous path of least resistance.

The microseismic mapping project, provided the first evidence from the field that the Barnett Shale stimulations were creating complex fracture patterns and were following pre-existing natural fractures, a fact that is now well verified.

Applying the Tools

Figure 2 shows the image of a narrower pattern of multiple fracture lineations, as compared to the Figure 1 well. Also shown is an asymmetric fracture growth to the Northeast that is believed to accurately reflect created fractures and was unrelated to detection limits. Until the microseismic imaging project revealed these various complex patterns, single, long, vertical fractures with a NE-SW orientation were thought to be the field's sole drainage pattern.

Figure 3 shows a Southeast stimulation orientation consistently toward a neighboring well, which happened also to be the monitoring well. In fact, as soon as the seismic array picked up events around the monitoring well a significant increase in background noise was recorded, which is consistent with fluids flowing into that wellbore. This was later confirmed by testing the borehole fluids. At the time, it was believed that this indicated changes in fracture orientation related to local structural perturbations of the stress field.

In other wells over the course of the project, the particular fracture shape illustrated in Figure 3 — having a more diffuse cloud of events and orientation perpendicular to the field's predominantly NE-SW orientation — was found to be representative of wells that inadvertently hydraulically fraced into fractures already being drained by a neighboring well. After observing the fracture patterns in each area of the field, the tight infill drilling patterns being used were altered to avoid interference between wells without diminishing the number of infill locations.

Relating Images to Production

In order to compare the fracture effectiveness of various wells documented in this paper, plots of daily production for each well were created. The plots in general revealed that the widely distributed fracture pattern, as demonstrated in Figure 1, seems to produce the most effective production rates. Wells with this type of pattern tend to deliver relatively high initial production rates that are more uniformly maintained relative to other wells, which have more significant hyperbolic declines. These high rates could be related to extensive contact between reservoir and fractures, as seen in the complexity of Figure 1.

Wells with a smaller, linear fracture network, as in Figure 2, tend to produce at moderate rates. And wells with orientations perpendicular to the preferred NW-SE natural fracture system, and/or following zones previously depleted by nearby wells, not surprisingly, produce the worst results.

In general, the numerous stimulation images taken over the course of the 2-year project indicated that generating a wide fracture zone appears to be a critical factor in Barnett Shale well performance.

Reservoir Drainage Implications

Prior to the insights gained from the microseismic images regarding the characteristics of the fracture networks generated during Barnett Shale stimulations, the drainage pattern of individual wells was believed to be elliptical in shape, symmetric about the treatment well and oriented in a NE-SW orientation. Clearly, the fracture networks stimulated during the imaged treatments were more complex and variable. The stimulated fracture networks appear to follow pre-existing fracture locations, orientations and spacings. The outer shape of the stimulated zone for any particular well is equally heterogeneous, and implies a similarly shaped drainage pattern for an individual well.

To optimize stimulations in the Barnett Shale, more extensive monitoring programs can be used to capture the local fracture complexity of existing wells. A clearer picture of fieldwide fracture network interplay would aid well placement, ensure that untapped reserves are not bypassed and help optimize fracture design. Having done this, real-time monitoring could be used by the engineering team to control or stop frac treatments based upon observable performance.

Outlook

The microseismic imaging project undertaken by Devon Energy in its Barnett Shale field to monitor fracture growth during hydraulic stimulation revealed a complexity of interplay between the hydraulic and natural fractures previously unimagined.

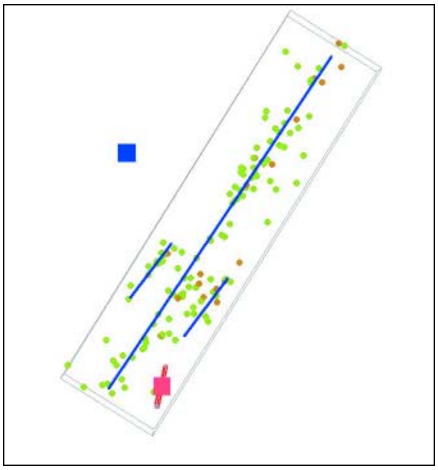

Figure 2. The frac treatment propagated to the northeast of this treatment well (red square) along three NE-SW trending orientations.

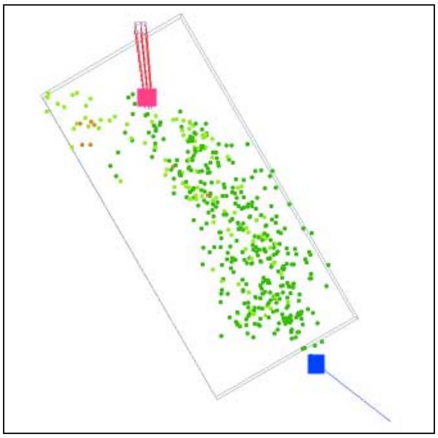

Figure 3. The diffuse cloud of events that were imaged while treating this well run perpendicular to the field's predominant NE-SW fracture orientation, indicating influence from fractures already being produced by a neighboring well.

To date, this fracture mapping technique has proved viable in reservoirs of all types, whether relatively unfractured or naturally fractured.

As well, passive seismic technology is also being used by the oil industry to monitor and map production-related microseismicity to define drainage, waterflood fronts, waste injection and casing failures. Clearly the use of passive seismic technology is on the upswing in the oilfield, especially in the context of the permanent seismic instrumentation in the intelligent oilfield. The Devon Energy project is an early contributor to this trend. E&P