Utilizing source mechanism and microseismic event location to identify faults in real-time using wireless seismic recording systems – an Eagle Ford case study

Karl Harris[1*] and Robert Bacon[2] present the latest developments in microseismic monitoring.

In a time when every penny counts it is critical for operators to become more efficient in all activities. This includes determining the best approach for microseismic monitoring during hydraulic fracturing. Surface microseismic monitoring measurements are particularly suited for determining rock failure mechanisms, such as dip-slip or strike slip failures. Coupled with the ability to acquire these measurements and determine the failure mechanisms in real time during fracturing operations, allows operators to take actions to deal with costly geohazards.

In this case study, the methodology related to data acquisition methods, and analysis and interpretation from microseismic monitoring to determine possible fault locations will be explained.

Case study

An oil and gas company operating in the Eagle Ford shale wanted to confirm possible fault locations and to gauge the extent of their reactivation as a result of hydraulic fracturing treatment. Surface seismic data indicated the potential presence of sub-seismic faults. Encountering such faults during hydraulic fracturing can increase the potential for uneconomic production from reactivated faults and could result in inefficient stimulation into those faults. The operator set out to monitor the treatment of the wells using surface-based microseismic technology. These microseismic results were then analysed after the treatment to develop a real-time fault identification workflow, allowing the operator to either alter or stop the treatment on future wells during pumping, if the fault reactivation was considered to be excessive.

MicroSeismic, Inc. worked closely with the operator to define clear project objectives for the microseismic acquisition to quantify the extents and locations of reactivated faults in an effort to determine if production was impacted, to measure the resulting fracture geometry, and to develop a real-time fault identification workflow for use on future wells. To this end, MicroSeismic, Inc. deployed a FracStar surface array to monitor the hydraulic fracturing of four wells in the Eagle Ford shale.

Array methodology

Additionally, MicroSeismic, Inc. used Wireless Seismic, Inc's RT System 2 real-time data acquisition system. The cable-free system was used to acquire microseismic monitoring data during hydraulic fracturing operations.

RT System 2 is a cable-free seismic data acquisition system that can replace a traditional cabled system. Contractors can use familiar planning tools and can expect the same performance to which they are accustomed, but no longer need to contend with river/road crossings complexities and the HSE exposure of a cabled system. RT System 2 features a high-capacity radio network with expanded bandwidth that supports the deployment of thousands of channels required by 3D surveys.

Wireless Remote Units (WRUs) (Figure 1) placed at each receiver location have a dual function: digitizing the geophone signals and relaying the data up the line of the backbone, as in a cabled system, but without the issues associated with cables. Because the radios need to communicate across the distance of only one group interval, they can operate on minimal battery power while supporting hundreds of channels in a line of geophones. Small bespoke lithium-ion batteries power the WRUs for the duration of their deployment. Test results, noise, battery capacity, geophone, and other data are communicated back to the central recording system in real time.

Data are transmitted down the line, from WRU to WRU, to a Line Interface Unit (LIU). The LIU converts the data into Ethernet packets and sends the data to the central recording system over a high-speed wireless link or through an armoured fibre-optic cable, as conditions warrant.

Unlike other cable-free seismic recording systems, data are delivered to the recording cabin in real time, in the

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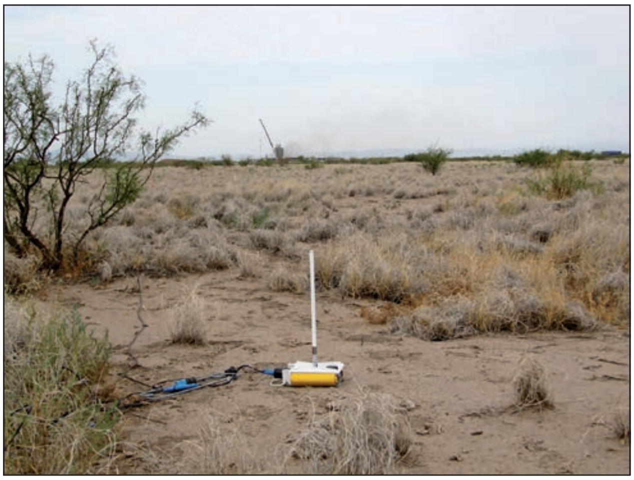

Figure 1 A line of Wireless Remote Units at the fracturing site.

familiar source-gather format. The recorded data are safe from theft or failure, and the observer can validate data quality and integrity without delay. Shot records are immediately available in a SEG format for viewing or real-time processing.

The central recording system features a familiar user interface, with spread map, real-time noise monitor, individual station status, and the seismic record. Operators of RT System 2 can easily understand and interpret the displays after a short period of training.

Combined with 'n Recorder Field Processing Unit real-time capabilities, the RT System 2 system has provided value to this particular project through its flexibility and speed.

Flexibility

While preparing for surface hydraulic fracture monitoring using MicroSeismic's FracStar array, operators frequently encounter challenges, including landowners who are reluctant to permit access to their land, and obstacles in the terrain, such as ponds, highways, creeks, and rivers. For example, a seemingly simple task, such as crossing railroad tracks, can be time consuming while waiting on approvals, and it can be expensive when utilizing a cable-based recording system. During this monitoring project, setbacks such as these were reduced or avoided by using the RT System 2.

Figure 2 demonstrates how difficult it can be to logistically place a cable-based system in permit-affected areas and finding a contiguous route for a cable to the north side of the 'no permit' zones. If a cable-based system had been used, it may have been necessary to use miles of equipment to 'cable around' the area using road right-of-ways. For these reasons, a cable-free system was the best solution.

By using the cable-free system, it was easy to lay the spread to the edge of the property, add extra WRUs on either side of the 'no permit' area (Figure 3), and add one Line Interface unit (LIU) per line with a short transportable antenna (Figure 4).

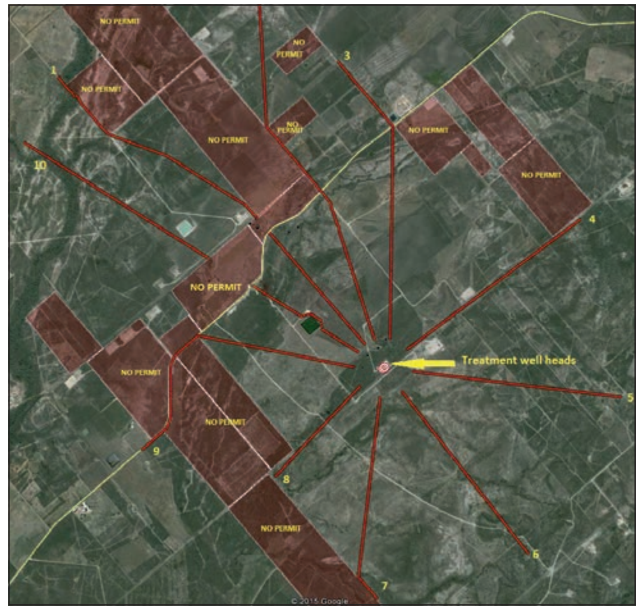

Figure 2 The FracStar array with permit status (red = No Permit).

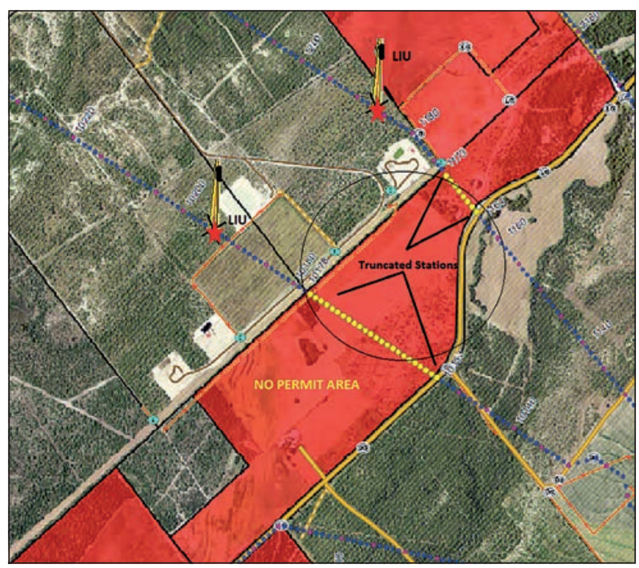

Figure 3 Expanded view of 'no permit' affected area with LIU locations.

Establishing communications with the units on the north side of the obstacle with the recording truck was simple, and the data streamed in with no human intervention. In total, the number of affected channels was limited to 33 out of 1200 locations. Eliminating cables made for easy layout and efficient use of personnel. The value and flexibility of RT System 2 became apparent when line moves, skips, and deviations were made quickly and easily. Crossing obstacles such as ponds, highways, creeks and rivers, proved to be effortless as well.

Efficiencies

Wireless Seismic's RT System 2 is a well thought-out system with many features specifically tailored for FracStar acquisition. The system effectively reduces manpower requirements, while improving layout time and cutting days off layout and pickup efforts, thereby increasing cost effectiveness.

The RT System 2 is compact and light, and allowed the layout crews to move larger amounts of equipment per trip, thus speeding up the deployment while reducing exposure to vehicle (UTV) incidents by lessening the quantity of trips each unit had to make to deploy the equipment on line (See Figure 5). The cable-free system allowed the crew to deploy and completely lay out 1072 channels on the first day, with the remaining channels laid out and the second day. Additionally, the spread was QC'd and tested on the subsequent day, saving one day of operations on a typical three-day layout required for cabled crews.

Real-time fault identification methodology

In developing a real-time fault identification methodology, it was clear to both MicroSeismic, Inc. and the operator that a clear set of guidelines was required to minimize subjectivity in decision making. Since the goal was to shut down a stage during pumping if a fault was observed to have been reactivated, the burden of such a decision would fall on the individual making such a judgment, which could be open to scrutiny. This type of decision is of critical importance for real-time decision making, as a fault reactivation that is readily apparent once the treatment is complete and is less obvious during the treatment. Thus, based on the results of this initial monitoring, two main criteria were identified for real-time fault detection to allow objective decision making, shear source mechanism and event location. Using this pre-defined criterion, the team would be able to determine whether or not a fault was being reactivated in such a way that would be potentially uneconomic in terms of treatment and production.

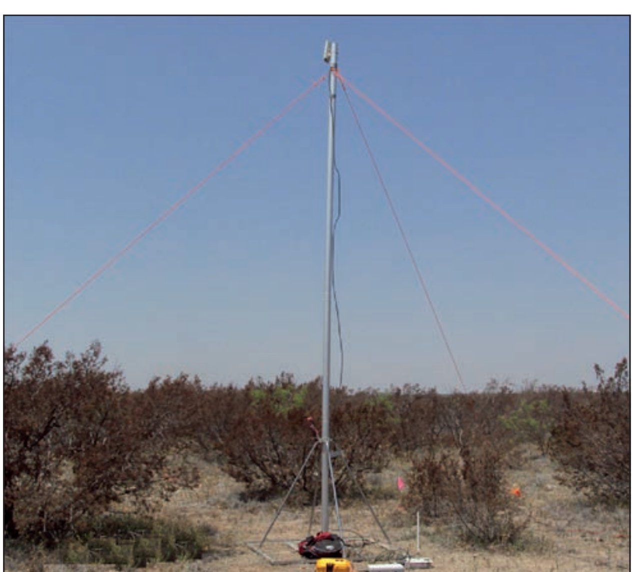

Figure 4 Line Interface Unit with transportable antenna.

Determination of source mechanism:

Microseismic events are produced by a slip or shear failure within the rock along a failure plane, often associated with natural fractures or faults. By detecting the microseismic waveforms generated by the event, the orientation and slip directions can be determined, allowing the description and characterization of the event in terms of strike, dip, and rake. A typical surface microseismic acquisition provides more than a thousand monitoring locations, spread over several square miles, allowing for accurate determination of the source mechanisms for the detected microseismic events. As opposed to a downhole array, which requires two or more monitor wells to detect and invert for a focal mechanism, a surface array can accomplish this with a single layout.

Typical surface microseismic provides measurements of first arrivals of P-waves over a large area. Figure 6 below shows examples of first arrival responses measured at the surface by a FracStar array for dip-slip and strike-slip mechanism, demonstraing spatial variation in the first arrivals. Using the geometry, polarity, and amplitude of the signal at each station, accurate source mechanisms can be computed, thus allowing for better location and understanding of given events. On the beach ball diagram, the boundaries between the dark and light quadrants represent the fault plane and auxiliary plane.

Utilization of source mechanism:

Two source mechanisms were identified in this case study: a dip-slip mechanism associated with induced fractures and natural fracture reactivation, and a strike-slip mechanism associated (in the Eagle Ford) with fault reactivation.

Figure 5 70 Wireless Recording Units (WRUs) loaded on UTV for deployment (equivalent to 70 FDU/cables).

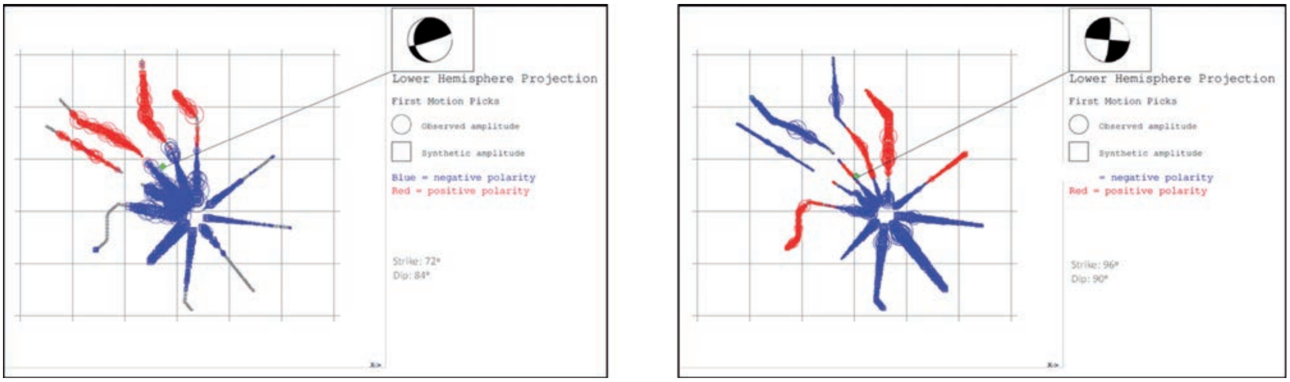

Figure 6 *Identifying Faults.*

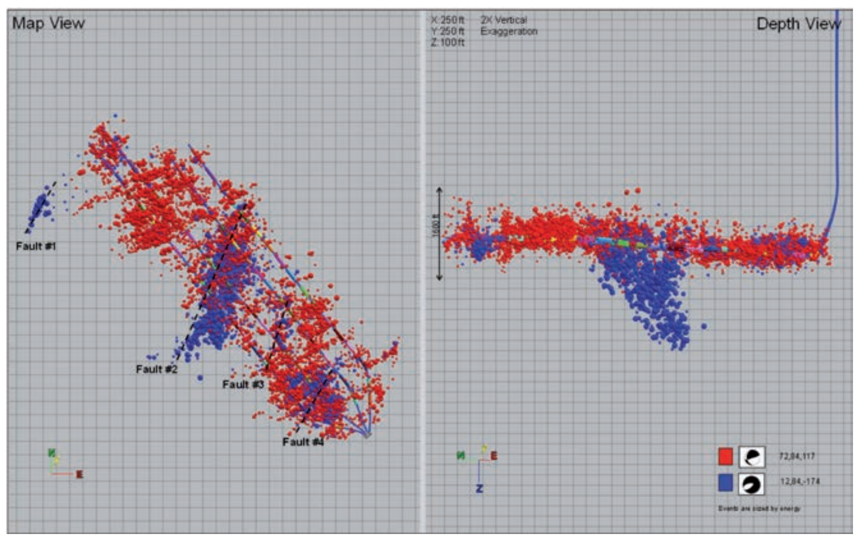

Figure 7 *Map view and depth view of microseismic events observed on the four-well pad, coloured by source mechanism. The four main faults observed in the project can be seen.*

The presence of strike-slip events alone indicates some fault reactivation, though looking at these events in isolation fails to provide any context to their occurrence. Observing many strike-slip events can indicate a high degree of fault reactivation. However, if this is coupled with numerous dip-slip events, the impact of strike-slip events is less significant than if there were few dip-slip events. Therefore, a simple metric was created to put the strike-slip events in context: the source mechanism ratio. By dividing the number of strike-slip events occurring in a stage by the number of dip-slip events, a context for the strike-slip events can be obtained. For this project, a strike-slip to dip-slip ratio of 0.75 was determined to be critical, with stages over 0.75 exhibiting a high degree of fault reactivation.

Observing this ratio alone proved useful. However, it did not consider cases where a fault was reactivating. During hydraulic fracturing, we are concerned with the location of the fault reactivation with respect to the wellbore. Figure 7 above shows multiple fault reactivations identified as Fault #1, Fault #2, and so on. Fault #1 was far enough off the wellbore that it might be reactivating due to stress alone, as opposed to fault #2, which might be taking fluid from the fracturing treatment. Reactivating Fault #1 may not be detrimental to the hydraulic fracturing, whereas, reactivating Fault #2 will result in significant loss of fluid and could negatively impact the production of hydrocarbons. To incorporate these cases into the real-time decision-making workflow, criteria for the distance of the reactivated fault to the wellbore was incorporated. This is computed as a moving average of the distance from the stage centre of strike-slip events. The inclusion of this moving average, combined with the strike-slip to dip-slip ratio, can be seen in Figure 8 below. This combination of factors serves to objectively determine the existence of fault reactivation during a stage, which could be detrimental to the success of hydraulic fracturing, allowing for impartial decision making during pumping.

The implementation across multiple stages of these detection methodologies can be seen in Figure 9. In the Stage 3 plot, no strike-slip events are observed, indicating no faults have been reactivated. In the Stage 4 plot, some strike-slip events are present. However, the strike-slip to dip-slip ratio remains low, and the strike-slip events are occurring near the

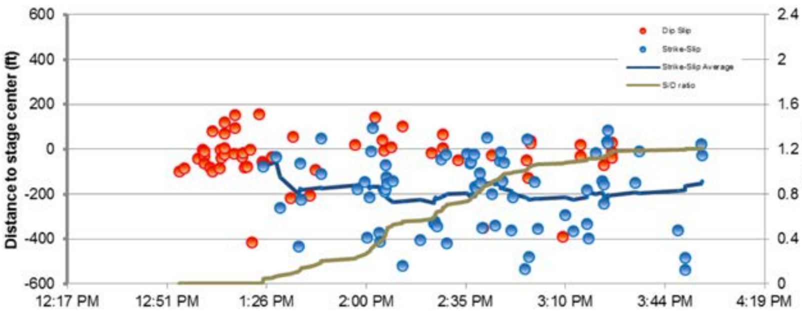

Figure 8 *Example stage plot showing events, strike-slip to dip-slip ratio, and strike-slip distance moving average as a function of time.*

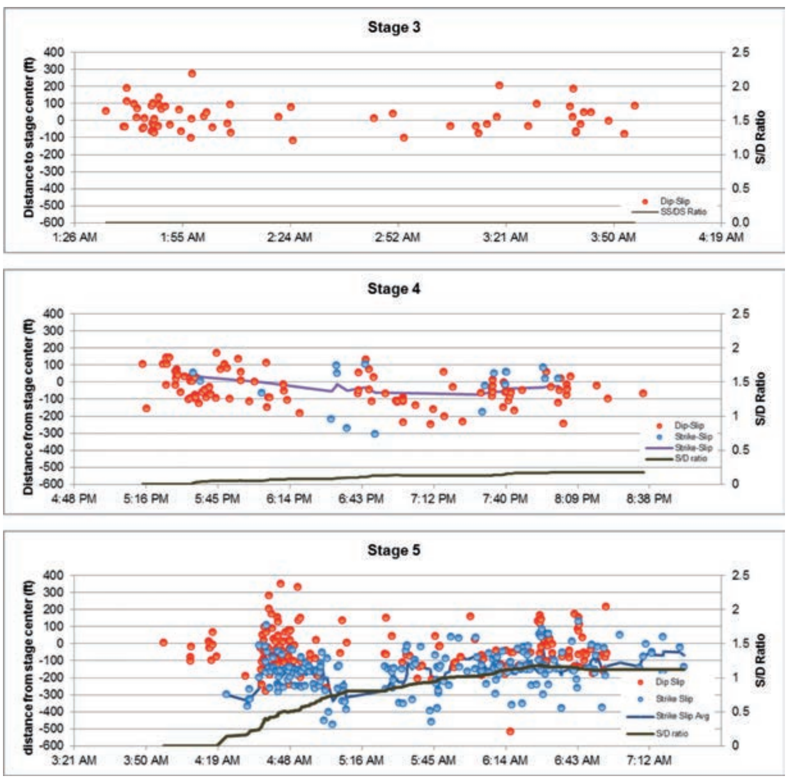

Figure 9 *Example stage plots showing dip-slip events, strike-slip events, strike-slip to dip-slip ratio, and strike-slip distance from stage centre moving average. The increasing strike-slip activity and distance from wellbore can be seen in progressive stages, indicating fault reactivation.*

wellbore. For this stage, neither of the two thresholds would be exceeding, so no 'stop pumping' recommendation would be made. On the final subplot, for Stage 5, a large number of strike-slip events begin occurring early in the stage, quickly raising the slip-slip to dip-slip ratio, while dropping the moving average for distance from stage centre. Depending on where the individual thresholds are set, a 'stop pumping' recommendation would be triggered early in the stage, saving the operator treatment costs from the stage, as well as reducing uneconomical production from the reactivated fault.

Outcome

From the microseismic analysis, four main faults were observed, as seen in Figure 7. Fault #2 is clearly the dominant fault, although all four faults had the potential to impact production. Based on the 'stop pumping' criteria and respective thresholds determined, a total of 11 stages were identified as having met the requirements to stop the treatment during the job. In these 11 stages, the 'stop pumping' triggers were hit at an average of 40% into the stage, creating a potential to save 60% of the fluid and pumping horsepower associated with the treatment. In terms of the uneconomic production, it is not trivial to estimate the impact of each reactivated fault, but suffice to say, if less treating fluid entered these faults, the uneconomic production would likely be reduced.

Beyond the impact related to this Eagle Ford case study, the real-time geohazard avoidance developed in this project has far-reaching implications for future development in this field and similar fields exhibiting risks of fault reactivation going forward. By observing the microseismic events in real-time and empowering operators to make strategic decisions, treatment costs can be minimized, while reducing the impact of fault-related uneconomic production increases value across the board.