Optimization of Stimulation Strategies Using Real-time Microseimic Monitoring in the Horn River Basin

Yuri Rodionov, yrodionov@slb.com

Richard Parker, Mike Jones, Zuolin Chen and Shawn Maxwell, Schlumberger

Tim Leslie , Larry Matthews, ConocoPhillips

GeoConvention 2012:Vision

Summary

Microseismic measurements are a valuable tool in helping to understand hydraulic fracture geometry in a variety of unconventional plays. Many times however, microseismic data is not processed until after the stimulation campaign is over. If data is acquired and processed in real-time the interpretation of microseismic data, coupled with the analysis of treatment parameters, can empower the engineers to make immediate changes to the stimulation strategy.

Horn River Basin exploitation is still in its early stages for many operators. Uncertainties existed relating to fracture propagation, extent, zonal isolation and stage interference, for ConocoPhillips in a horizontal treatment well adjacent to a vertical exploration well. The vertical well was intended to be subsequently used for pressure monitoring. It was important to the operator that the treatment induced fractures did not break into this future monitoring well. Two strategies were engaged to ensure this; (1) perforations were located to avoid hitting this well based on the expected fracture direction and (2) real-time microseismic monitoring of the geometry in order to stop the completion if it grew too close. Additionally, the observation of overlaps of the microseismic events from adjacent stages facilitated increasing the distance between stages. During several stages the treatment process came close to screening out. The real-time monitoring showed clustering of events close to the perforations as the proppant began to block the fracture network. This prompted intervention by either cutting proppant or pumping a viscous pill to increase fracture width and 'sweep' proppant out into the fracture system.

Introduction

As in many other ultra-low permeability shale plays, the main goal of stimulation treatments in the Horn River Basin is to increase the contact area between the horizontal wellbore and reservoir rock. This goal is achieved through multistage hydraulic fracture stimulation treatments typically performed using a plug-and-perf technique. Due to the high heterogeneity of shale reservoirs and changes of petrophysical properties along the horizontal wellbore, fracture geometry can vary greatly from stage to stage in the same lateral. In many cases, the original completion design needs to be modified during the course of the project in order to account for these changes, thereby achieving more optimal placement of hydraulic fractures. This involves implementing modifications to the perforation strategy and the treatment design. An additional challenge, which often arises during the completion process, is difficulty in placing the proppant. This can result in premature treatment termination due to near-wellbore screenouts. Screenouts are an operational risk because they often result in expensive cleanout runs with coiled tubing and a substantial amount of non-productive time. As will be demonstrated in this paper, microseismic data can be used to identify the near-wellbore activity and make prompt interventions into the pumping schedule to remove near-wellbore restrictions and re-establish injectivity. Bailhy et al (2006) discuss a similar approach in the Bossier sand and there are other examples in the literature.

The approach requires the ability to monitor the fracture network in real-time using microseismic, processed and visualized in real-time along with the familiar pumping data. Real-time event location requires event location techniques which do not rely on hand-picking of compressional and shear arrival times, such as the Coalescence Mapping technique (Drew et al. 2005).

Background

The subject well was drilled in the direction of minimum horizontal stress to achieve transverse fracture orientation. A total of 10 treatment stages were planned. An offset vertical well was used for deployment of the monitoring tools to record microseisms. The locations of perforations were selected to keep a gap between stages 8 and 9 in order to avoid fracture growth into the offset monitoring well. Figure 1 below presents a 3D view of the monitoring and treatment wells with the planned perforation intervals.

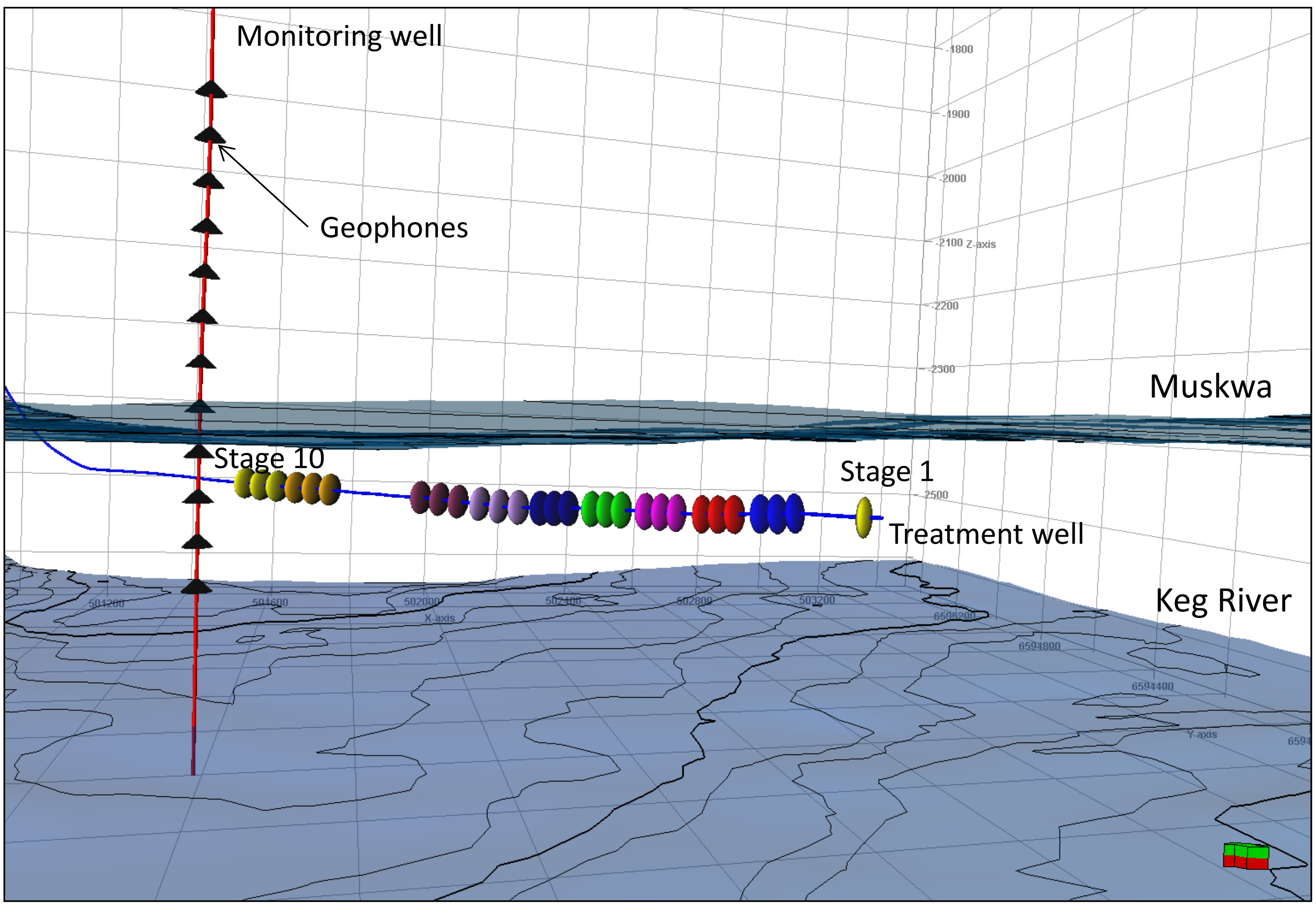

Figure 1: 3D view of treatment and monitoring wells and formation surfaces

Case Study

Early identification and avoidance of screenouts

During the pumping of stage 3 the treating pressure increased rapidly during the high proppant concentration phase which resulted in a near wellbore screenout. The rapid pressure increase indicated that screenout had occurred in the near wellbore region. This type of screenout is especially difficult to predict since the treating pressure trend remains flat, giving no prior warning. Engineers typically do not have enough time to react to avoid the situation. Microseismic events recorded prior to screenout were located in close proximity to the perforations. These events were recorded approximately ten minutes before any noticeable change in the pressure trend was observed. These microseismic events indicate that rock was failing in the near wellbore region, meaning that fracture propagation away from the wellbore was compromised. Therefore preventing proppant from being transported away from perforations, resulting in the inevitable screenout.

Based on the observations from stage 3 it was decided to introduce viscous fluid ‘pills’ into the pumping schedule when the real-time microseismic data indicated near-wellbore proppant bridging on subsequent stages. It was believed these sweeps would increase near wellbore fracture width and displace proppant farther into the fracture network. This technique was successfully applied on subsequent stages and no further screenouts developed. The example below demonstrates how this methodology was implemented on stage 4.

Figure 2 shows the stage 4 microseismic fracture geometry evolution. The top graph is a ‘fracture speed’ plot, where the distance from the perforations to each microseismic event is plotted versus time. The slope of the green line represents the average speed of microseismic lateral growth away from the perforations. The middle graph shows the treatment plot with the microseismic event rate overlain. The treatment data is divided into three time periods representing different fracture behavior as observed from the microseismic data. Microseisms on the map view (bottom graph) are colored in accordance with these time periods.

The ‘fracture speed’ plot shows that the fracture initially extends away from the wellbore (yellow time period). At the yellow/blue boundary the length extension ceases as proppant bridging begins in the near wellbore region. Microseismic activity continues to develop in the near wellbore region (blue time period) and the subsequent treating pressure increase occurs several minutes later. Note that the first near wellbore microseismic events (and reduction in ‘fracture-speed’) were detected before a noticeable pressure increase could be seen on the treatment plot. A viscous fluid pill was pumped downhole which resulted in microseismic event locations shifting towards the tip of the fracture indicating that the near wellbore proppant restriction was displaced (red time period). Treating pressure decreased as a result and pumping continued according to the design. This technique was successfully applied multiple times throughout the project avoiding any further screenouts.

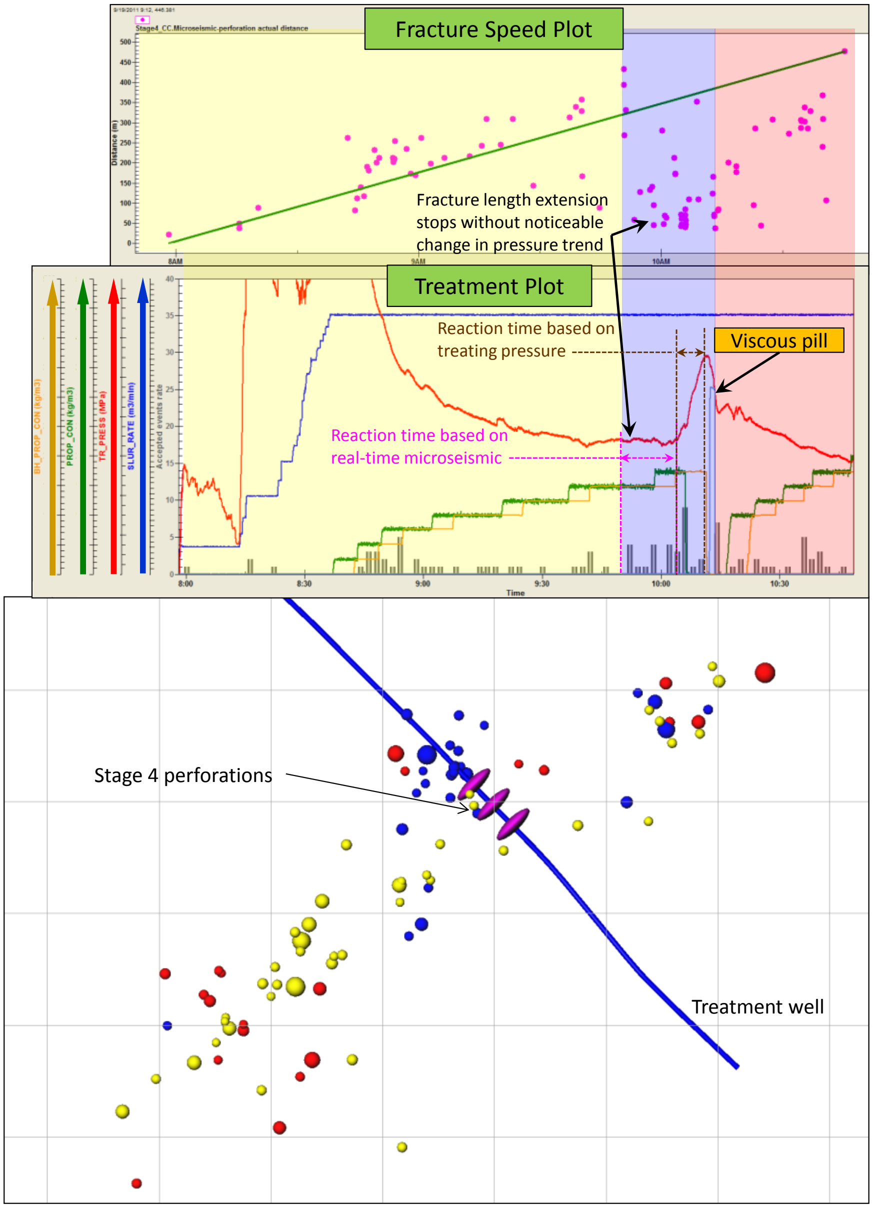

Figure 2: Stage 4 fracture speed plot (top), treatment plot (middle) and map view of microseismic events (bottom)

Perforation strategy optimization

Real-time microseismic data was also used to optimize the perforation spacing within each stage and the distance between stages. Figure 3A shows the original perforation intervals of stage 5 to 8. After stage 6 was pumped microseismic data indicated a clear overlap between stages 5 and 6 (Figure 3B). This led to the decision to increase spacing between stages 6 and 7. This modification resulted in good separation between the microseismic clouds of stages 6 and 7 (Figure 3D).

The observed geometry for stage 7 (lilac coloring in Figure 3D) partially covered the volume that had been intended to be treated by the frac at the original stage 8 location. Taking this into account, and including the previous learnings about fracture azimuth and extent, it was decided to move the original stage 8 location further up the borehole, to the uphole side of the monitor well. Pumping the eighth fracture treatment stage from the originally planned location immediately uphole from stage 7 (the lilac volume of Figure 4D) would run a severe risk of compromising the integrity of the monitor well.

The overall result of these adjustments was that maximal stimulation coverage was obtained with minimal overlap between stages despite requiring the use of only 9 stages instead of the originally planned 10. Completion costs and operating time were both reduced, showing the value of the real-time microseismic monitoring.

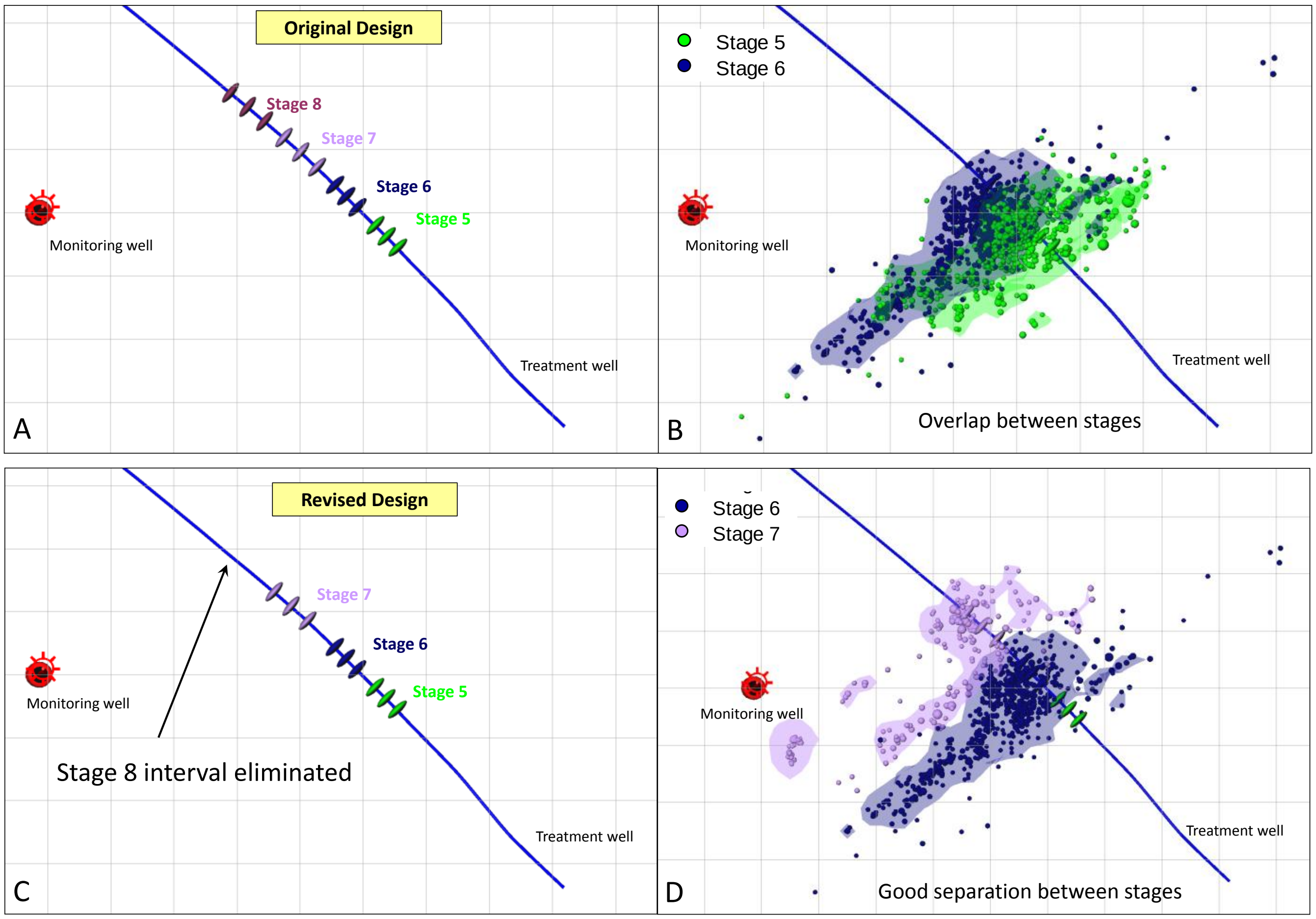

Figure 3: Map view of microseismic events and perforation intervals. Pictures A and B show the overlap between stages 5 and 6. Pictures C and D show the revised perforation strategy and improved separation between stage 6 and 7 event clouds.

Real-time changes to pumping schedule

One of the constraints on the completion process was the requirement to use the vertical monitoring well for pressure monitoring in the future. The risk that the fracture network generated by stage 8 might reach the monitor well was mitigated by the use of the real-time microseismic monitoring results. While stage 8 was being pumped, a multidisciplinary team of geophysicists, geologists, completions engineers and geomechanical specialists was able to watch the pumping data and microseismic in the same venue, on the same platform and at the same time. This team was able to pick the optimum time during the fracture development at which to terminate the stage so that the stage productivity could be maximized without the risk of damaging the observation well.

Figure 4 shows the map view of the microseismic events from stage 8. The colour coding shows that initial microseismic activity occurred very close to the wellbore (blue) and then grew away from the well as the colours change towards red. As can be seen the decision to stop pumping the stage was taken when the microseismic events neared the monitor well.

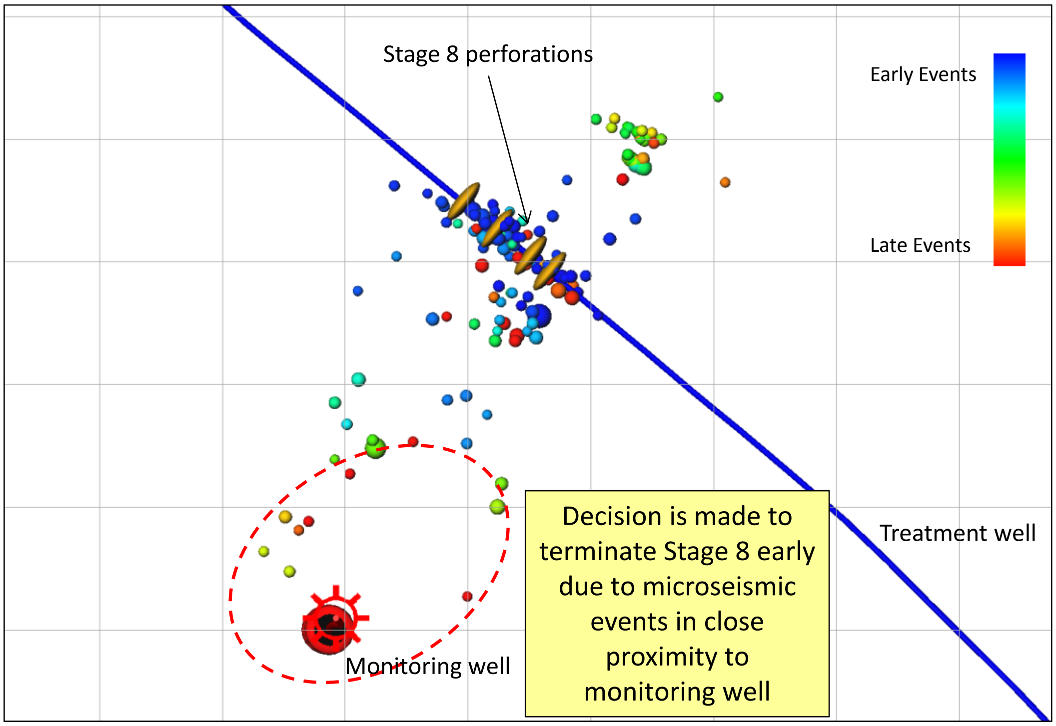

Figure 4: Map view of stage 8 microseismic activity showing the events in close proximity to monitoring well

Conclusions

The application of real-time microseismic monitoring during the fracture treatment significantly reduced the financial and technical risks by:

- Allowing early remediation of imminent screenouts.
- Providing timely feedback which allowed alteration of the perforation locations to avoid frac intersection with the monitor well as well as avoid overlaps between adjacent stages of the fracture treatment.
- Enabling maximization of pumped proppant in stage 8 while still avoiding compromising the future monitor well.
- Reducing the original number of stages from 10 to 9 while still achieving the design objectives in the volume of rock stimulated and the amount of proppant placed.

Robust and credible event locations in real-time are the key to making meaningful intervention decisions.

Acknowledgements

The authors would like to acknowledge ConocoPhillips for their permission to show their data.

References

Baihly, J, P Laursen, G. Ogrin, J. Le Calvez, R Villarreal, K Tanner, and L Bennett. “Using Microseismic Monitoring and Advanced Stimulation Technology To Understand Fracture Geometry and Eliminate Screenout Problems in the Bossier Sand of East Texas.” In *SPE Annual Technical Conference and Exhibition*. San Antonio, Texas, 2006.

Drew, Julian, H. Leslie, Philip Armstrong, and Gwenola Michard. 2005. “Automated Microseismic Event Detection and Location by Continuous Spatial Mapping.” *Proceedings of SPE Annual Technical Conference and Exhibition* (October): 1-7. doi:10.2523/95513-MS.