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Duvernay Fracturing: From Microseismic Monitoring to Unconventional Fracture Model Construction

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Summary

Microseismic hydraulic fracture monitoring, commonly used in the modern oilfield industry, is one of the few techniques available to gather information about fracture dimensions. However, questions concerning uncertainty, ambiguity and bias associated with the technique remain (Cipolla et al. 2010; Cipolla et al. 2011; Thornton and Eisner 2011). A common problem associated with downhole monitoring is poor azimuthal station coverage, which introduces an observational bias. Multiple monitor locations can reduce this bias and provide a more reliable locus of microseismic hypocenters (Johnston and Shrallow 2011). In our case study microseismic monitoring was performed with downhole geophones at the heel of two wells and with sensors deployed on the surface. The availability of multiple receivers allowed the results to be combined, the event location uncertainties to be reduced, and the potential biases introduced by the downhole monitoring array to be minimized. The combination of multiple receivers provides a rare opportunity to run and calibrate a more accurate unconventional fracture model (UFM).

Microseismic data were acquired in two horizontal wells one with 16 stages the other with 17 during completion of the Duvernay formation. In total, approximately 92,000 microseismic events were recorded and located. The microseismic event clouds for both wells differ from each other, possibly reflecting local geomechanics and treatment type differences as well as differences in rock fabric. The UFMs were constructed for both wells using a geocellular regional model with 1D geomechanical and petrophysical inputs. The modeling result suggests that the UFM “follows” over 60% of microseismic events within the region of modeling.

Introduction

Microseismic monitoring is a standard technique for monitoring fracture propagation during hydraulic fracturing treatments. Detection and location of recorded microseismicity might provide information about strike direction and azimuth of induced fractures. To a limited degree, microseismic can also provide information related to the stimulated reservoir volume. Numerous microseismic monitoring projects have demonstrated that fractures generally tend to be more complex than anticipated. It is of high importance to have knowledge about fracture complexity in the reservoir when planning completion strategy and treatment design effectively.

Fracture models can be used in the oil field as a predictive tool for fracturing design and adjustment, replacing the expensive approach of “trial and error”. Microseismic data serve as an input to calibrate the fracture models. If the magnitude of stress anisotropy cannot be predicted reliably, microseismic might be the only data available for fracture model calibration (Li et al. 2014). A recently developed unconventional fracture model (UFM) (Chuprakov et al. 2011; Kresse et al. 2013; Cipolla et al. 2011; Ramanathan et al. 2014) was applied in this case study. The UFM was tested for its ability to describe the general behavior of fracture networks in distinctively different fracture geometries of two wells within the Duvernay formation.

Microseismic Monitoring results

The Duvernay formation is located in the western Canadian sedimentary basin and consists of bituminous and calcareous shale as well as argillaceous limestone. Productivity is enhanced by an overpressured reservoir. Microseismic data were acquired during a plug-and-perf completion in the Duvernay formation in two horizontal wells (Well A with 17 stages and Well B with 16 stages).

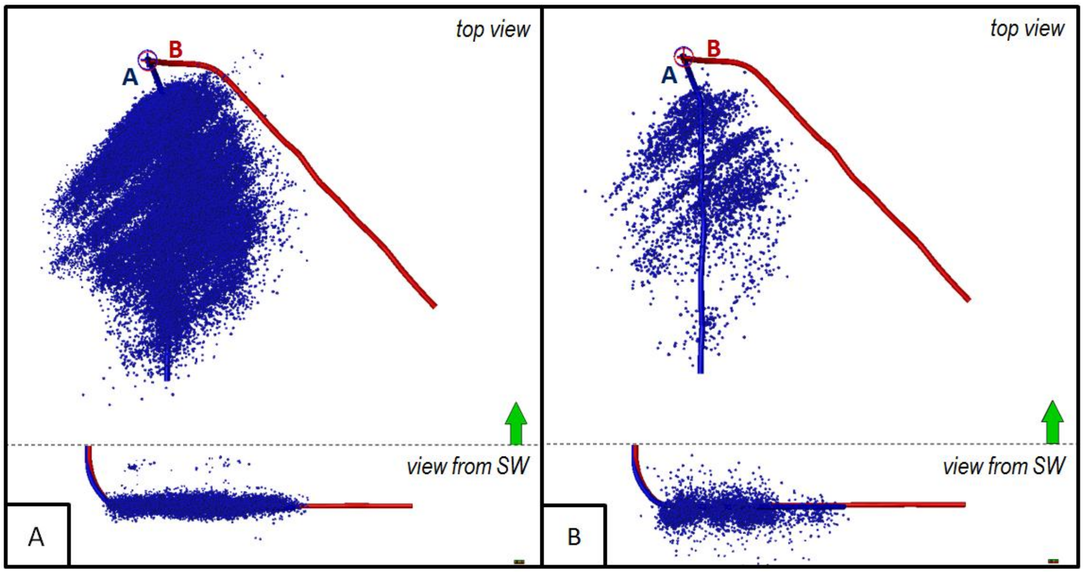

Figure 1: Microseismic events located at Well A. A) With downhole array; B) With surface network.

A network of 2,100 three-component surface sensors as well as 20 downhole geophones (30 m spacing) were used for microseismic monitoring. Downhole geophones were anchored at the heel of Well A to monitor Well B and at the heel of Well B to monitor Well A. Approximately 68,000 events were recorded in Well A and 23,780 recorded in Well B with the downhole array (Figure 1A). The surface network recorded 3,860 events in Well A and 1,410 events in Well B (Figure 1B). Figure 1 shows the events only recorded at Well A. The well-known advantages and disadvantages of surface versus downhole monitoring can be observed; e.g., a reduction in detection threshold and improved vertical constraint of microseismic events recorded by the downhole instrumentation. Figure 2 shows the magnitude distance plot for all events recorded with the downhole geophones, with the magnitudes ranging between $-2.7 \leq MW \leq -0.1$. The magnitudes of events located with the surface network range between $-1.5 \leq MW \leq -0.3$ (not shown in Figure 2).

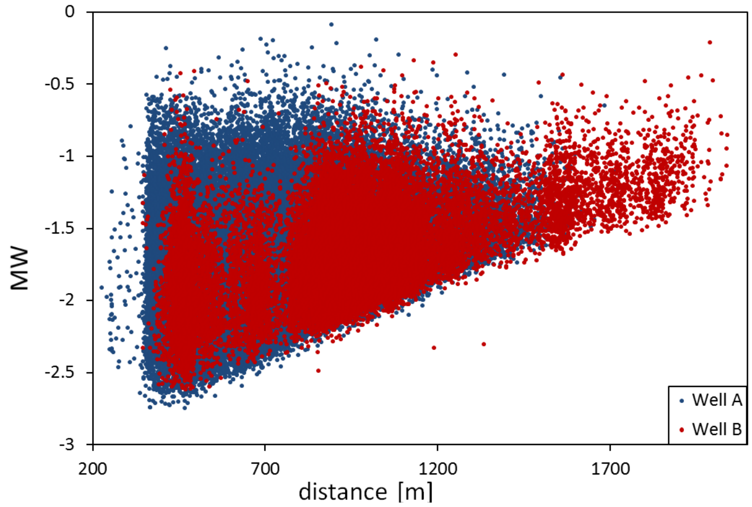

Figure 2: Magnitude versus distance plot for Well A and Well B

Geocellular Geological Model and Unconventional Fracture Model Construction

Microseismic events recorded by the downhole array and validated by surface monitoring were used for calibrating the UFM. A 3D static geocellular geological model, which included petrophysical and geomechanical data, was constructed to be used for hydraulic fracturing design modeling with the pilot well data.

Seismic horizon interpretations, seismic inversion properties, geomechanical/petrophysical evaluations, and microseismic measurements were integrated in the regional geological model. This is a similar geocellular modeling workflow as described in Ramanathan et al. (2014). Figure 3 shows an example of the 3D geological modelling. The location of the microseismic events within different formations were analyzed and is graphically represented by histograms at the bottom of Figure 3. As indicated, more than 65% of events are localized within the Duvernay formation.

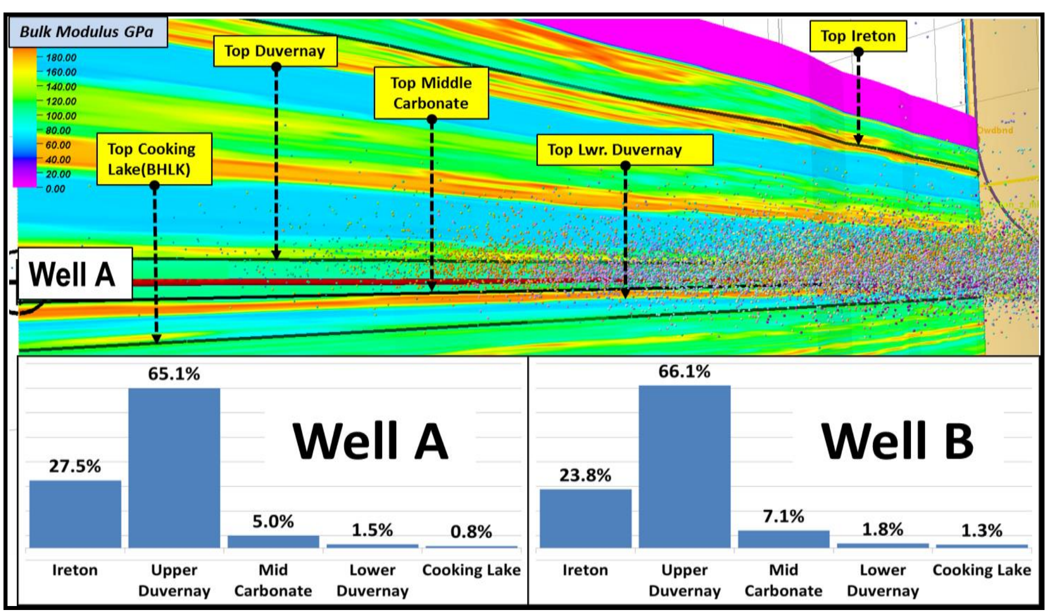

Figure 3: 3D Geocellular model. Bulk modulus (GPa) is displayed in the cross section at Well A. Histograms at the bottom represent microseismic events localization (%) in the different formations. Seismic data are owned by Seitel, Inc.

The authors refer to Weng et al. (2011) for the theoretical background of UFMs. These models are capable of simulating the interaction of hydraulic fracturing with natural fractures, including crossing, propagation/dilation, deformation, interfracture fluid flow, and proppant transport/settling. Interaction between hydraulic fractures with natural fractures creates complexity. The model was validated using experimental data in multiple studies (Gu and Weng 2010; Kresse et al. 2012). The UFM is integrated within the Schlumberger E&P software platform, allowing for the combination of microseismic data with complex geocellular reservoir models. The results can then serve as input for integrated production modeling software. The ability to integrate microseismic data allows fracture geometry to be calibrated and further validates parameters such as discrete fracture network (DFN) patterns (Figure 4) obtained from seismic data/borehole image analysis, natural fracture network patterns (spacing, length), and horizontal stress anisotropy (Li et al. 2014).

UFMs were built for multiple fracture treatments for both Well A and Well B. Examples of model calibration using microseismic data are displayed in Figure 4. Horizontal stress anisotropy calibration is essential for unconventional fracture modelling, and for this case study, the estimated range was 1.2 to 3.8 MPa between the varying layers. The final UFM calibration was performed for the stages in the middle of the well (~1400 m from the receivers), minimizing the effect of microseismic detection limits (Figure 2). The average fracture geometry for the well was estimated as to be hydraulic/propped length 480/420 m and maximum height/ average height 40/25 m, respectively.

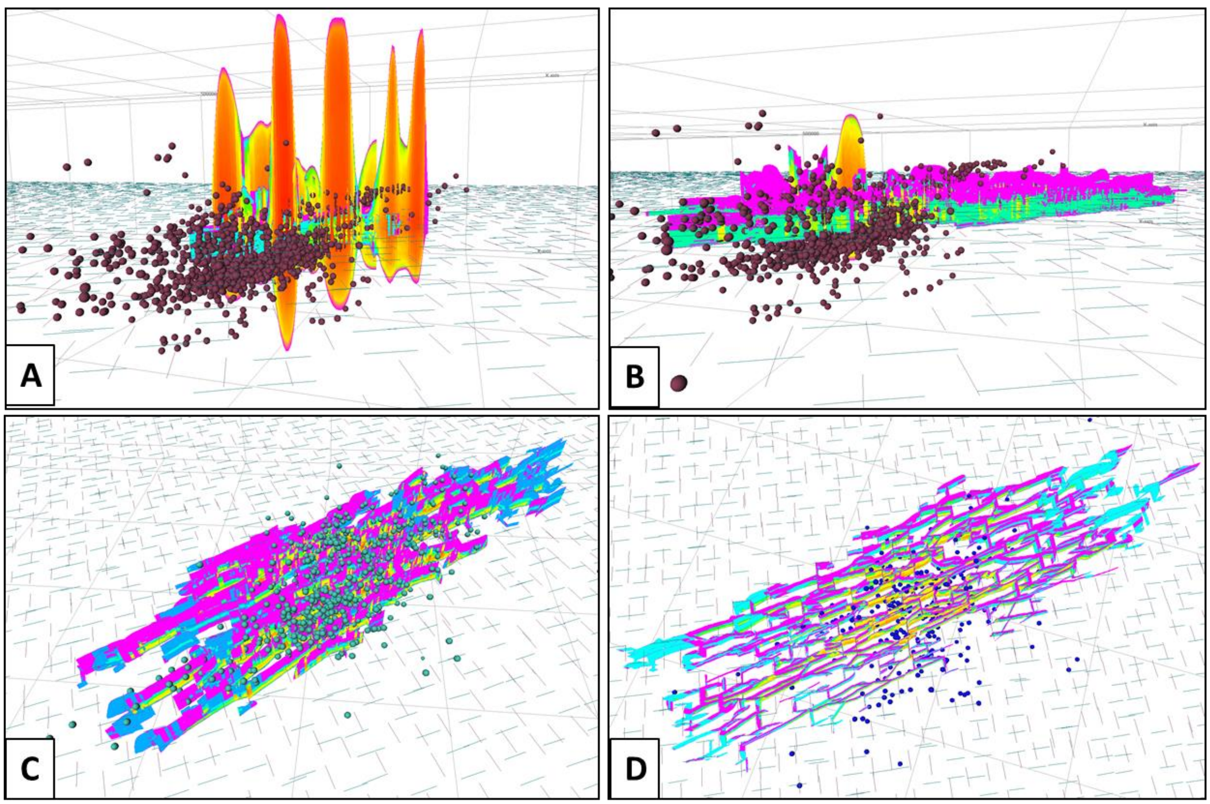

Figure 4: UFM microseismic calibration for different horizontal stress anisotropies. A) Heel stage with overestimated (~5 times) stress anisotropy; B) Heel stage with overestimated (~2 times) stress anisotropy; C) Heel stage-adjusted stress anisotropy; D) Model validation for toe stage. The color of the fracture model represents different fracture width contour. Black “dashed” background lines are the projection of the DFN pattern to the horizontal plane.

Conclusions

Microseismic data were used to calibrate unconventional fracture models for a multistage fracturing treatment in the Duvernay formation. Hydraulic fracture dimensions, natural fracture network parameters, and horizontal stress anisotropy parameters are estimated. The model will be further calibrated with production data, allowing it to be used as a predictive tool. The model can then be applied to achieve maximum fracture performance and simulating different senstivities with varying frac schedules, fluids, and proppants.

Acknowledgements

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