An Integrated Geomechanical and Microseismic Study of Multi-Well Hydraulic Fracture Stimulation in the Bakken Formation
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Introduction

The Mississippian-Devonian Bakken formation is a restricted shallow-water mixed carbonate-clastic sequence deposited over most of the deep part of the Williston Basin (Sturm and Gomez, 2009). Utilization of horizontal drilling and multi-stage hydraulic fracturing led to the successful development of the Elm Coulee (Montana) and Parshall (North Dakota) fields and demonstrated the great potential of the Bakken formation. Despite the generally successful exploitation of the Bakken formation, questions remain regarding how to optimize hydraulic fracturing and the importance of pre-existing natural fractures as fluid pathways in the reservoir.

To help address these issues, we first report development of a geomechanical model that includes knowledge of the magnitude and orientation of principal stresses, the existence and orientation of natural fractures and faults and mechanical properties of the formations being produced. In addition, as analysis of microseismic event locations can be used to better understand fracture networks after hydraulic fracturing stimulation (Fehler et al., 1987; Maxwell et al., 2002; Phillips et al., 1998; Rutledge et al., 1998; Williams-Stroud, 2008), and the stress state will influence both the hydraulic fracture propagation and the distribution of microseismic events. Therefore, linking observations of microseismic data with geological and geophysical information can help us better understand the geomechanical properties of the Bakken formation and to understand the role of pre-existing fractures and faults on the effectiveness of hydraulic fracturing stimulation in this shale oil reservoir. We hope this highly integrated approach will demonstrate the significance of geomechanics in guiding successful multi-stage fracturing performance in shale reservoirs. Relatively few published studies (Tezuka and Niitsuma, 2000; Verdon et al., 2011) have attempted to link microseismic events with the geomechanical properties of the reservoir and their impact on the hydraulic fracture stimulation.

Geological and geophysical characterization
The study area consists of three horizontal production wells (X, Y, Z) and six vertical monitoring wells (A-F) (Figure 1). Our study focuses on stimulation of wells X and Z. The middle well, Y, was hydraulically fractured and produced for about 2.5 years prior to stimulation of wells X and Z. Well-log data, including gamma ray, electrical resistivity, density, and P- and S-wave sonic velocity are available for petrophysical analysis in vertical well A, B, D, E and F.

Figure 1: Well trajectory of both (a) map view, and (b) North-South cross view

Well logs from vertical well A are shown in Figure 2. The total thickness of the Bakken formation is ~140 ft in the study area, with the top of the reservoir at a depth of approximately 10,000 ft. Wells X, Y and Z were drilled in the Middle Bakken. As shown in Figure 2, the Upper, Middle and Lower Bakken members can be easily distinguished from gamma-ray logs. The high gamma ray and high resistivity indicate the oil-saturated organic-rich shale layer in both the Upper and Lower Bakken, and the low gamma ray and low resistivity in the Middle member is an indication of the target layer calcitic, dolomitic siltstone. The Upper and Lower shales are also characterized by lower density (~2.3 g/cm$^3$) and lower $V_p$ and $V_s$ values which can be attributed to both lithology (clay- and organic-rich shale) and fluid saturation differences.
Figure 2: Petrophysical log collected from well A showing the lithological profile across the Bakken formation

Geomechanics of the study area

To build a quantitative geomechanical model we follow the general procedure outlined in Zoback et al. (2003) and Zoback (2007) to constrain the orientations and magnitudes of the principal stresses in the reservoir. Unfortunately, there are no image logs to determine the orientation of the maximum compressive stress from the orientation of compressive and/or drilling-induced tensile wellbore failures.

The magnitude of vertical principal stress is determined from the weight of the overburden, and the pore pressure ($P_p$) is available from DFIT (Diagnostic Fracture Injection Test) data. The ISIP (Instantaneous Shut-In Pressure) is also available from the DFIT test to constrain the magnitude of $S_{hmin}$. Rock mechanical properties are estimated by Weatherford lab from Bakken core samples from well A (provided by Hess Corporation). The values are listed in Table 1.

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Values @ Middle Bakken</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>$S_v$</td>
<td>73 MPa (1.05 psi/ft)</td>
<td>Integration of density log</td>
</tr>
<tr>
<td>$S_{hmin}$</td>
<td>55-59 MPa (0.79-0.85 psi/ft)</td>
<td>DFIT data</td>
</tr>
<tr>
<td>$P_p$</td>
<td>45MPa (0.66 psi/ft)</td>
<td>DFIT data</td>
</tr>
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<td>Biot’s Coefficient</td>
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<td>Common estimate</td>
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<tr>
<td>Young’s Modulus</td>
<td>26 GPa</td>
<td>Rock Mechanics Test</td>
</tr>
<tr>
<td>Poisson’ Ratio</td>
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<td>Rock Mechanics Test</td>
</tr>
<tr>
<td>UCS</td>
<td>110 MPa</td>
<td>Rock Mechanics Test</td>
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<tr>
<td>Internal Friction</td>
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<td>Rock Mechanics Test</td>
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<tr>
<td>Sliding Friction</td>
<td>0.6</td>
<td>Common estimate</td>
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</table>

Previous studies reported the orientation of $S_{Hmax}$ approximately N40-50°E within the Bakken formation, Williston Basin, North Dakota, based on drilling-induced tensile fractures observed in FMI image logs obtained from 3 horizontal wells in the Nesson State Field, which is close to the study area (Olsen et al., 2009). Using the rock mechanical properties, as well as estimates of $S_v$, $S_{hmin}$ and $P_p$ from this study, we built a separate geomechanical
model to predict the occurrence of tensile fractures along a horizontal well with the same orientation E-W as described by Sturm and Gomez (2009) and Olsen et al. (2009). Preliminary results suggest that when $S_{H_{\text{max}}}$ orients N40-50°E and ranges between 0.9-1.2 psi/ft, transverse tensile fractures would occur at the top and bottom of the well, whereas when $S_{H_{\text{max}}}$ with the same magnitude range but orients N75-80°E, axial tensile fractures are predicted. Sturm and Gomez (2009) reported that the transverse tensile fractures have higher aperture at the top and bottom of the well with dip angle greater than 80°; therefore, we believe that the orientation of $S_{H_{\text{max}}}$ ranges N40-50°E in the study area. However, due to lack of detailed drilling information and fracture description, we could not further constrain the magnitude of $S_{H_{\text{max}}}$, and the stress state indicates either a normal faulting or a strike-slip faulting regime.

**Microseismic events during hydraulic stimulation**

Microseismic events during hydraulic fracturing of wells X and Z were monitored with deep, ~1900 ft-long, 40-level, three-component geophone arrays in the six observation wells (Figure 3). The spacing between levels in each array was 49.2 ft. The stimulation was first performed along well X from toe to heel, and consisted of 29 stages, followed by another 38 stages along well Z. For both wells, different methods were used to complete stages: Stages 1-18 (well X) and stages 31-49 (well Z) used a single ball-activated sliding sleeve with swell-packers; Stages 19-29 (well X) and stages 50-67 (well Z) used pump-down perforation guns with bridge plugs. Both stimulations used a hybrid fluid system (slickwater, linear gel and cross-linked gel), sand and ceramic proppants. The fluid volumes injected during stimulation in well X and well Z were ~72 Mbbls and ~84 Mbbls, respectively.

A total of 6499 treatment-induced microseismic events were detected and located (Figure 3a, 3b). Event histograms of each stage (Figure 3c) show that the number of events in several stages (e.g. stages 2-4, stages 50-53) is much higher than in other stages.

![Figure 3](image-url)

**Figure 3:** (a) Map view of entire microseismic events during hydraulic fracture stimulation. (b) North-South cross view of the entire microseismic events. (c) Histogram of number of events for each stage of the two horizontal wells.

During hydraulic fracture stimulation one expects Mode I (opening mode) fractures to generally open in a plane perpendicular to the least principal compressive stress and parallel to the direction of $S_{H_{\text{max}}}$. Therefore, as the microseismic events are associated with slip on pre-existing faults surrounding the hydraulic fractures, they are
generally expected to form an elongated cloud extending bilaterally from the perforations when the well is being pressurized (see for example, Fisher et al. (2004)). However, the great majority of events located in this study are not consistent with this pattern as described below.

**Events along wellbore Y** - The first unusual observation of the seismicity is that events along well Y are observed during pressurization in the majority of stages in wells X and Z. Well Y is the parallel well located between X and Z that had been in production for about 2.5 years. Figure 4 shows that the events associated with stage 3 (shown in green) are clustered near the perforations in well X. Although the injection pressure of stages 3 and 4 are similar, the great majority of the events associated with stage 4 (shown in purple) occurred along the length of well Y thousands of feet southward of the perforation location, rather than in proximity to the toe of well X.

The pressure records of wells X and Y during stages 3 and 4 are also shown in Figure 4c. It can be seen that the events along well Y during stage 4 are associated with increasing pressure in well Y during pressurization of well X. During stage 3 stimulation, when most of the events clustered close to the perforation locations, the pressure in well Y remained constant at ~2000 psi downhole pressure (Figure 4c). However, during stimulation of stage 4, a few events first occurred close to the perforation location but they were quickly followed by the majority of events located thousands of feet southward along wellbore Y, indicating that fluid pressure propagated. In fact, the sudden pressure increase in well Y confirms that fluid pressure was affecting well Y, either through pre-existing natural fractures and faults, and/or through fluid pathways created during the stimulation of well Y years earlier.

**Events cluster at multiple depths** - As illustrated in Figure 5, another unusual observation is that the microseismic events can be subdivided into two groups: one mainly clustered within or slightly above the Middle Bakken formation and the other clustered at a much shallower depth in the Mission Canyon (MC) formation about 800 feet above the well depth, but few events are located in the Lodgepole formation. There are more microseismic events located in the MC formation than in the Bakken.

Figure 5 also shows that the stages associated with large number of events tend to have events in the MC formation, not the Bakken. In particular, stages 2, 3 and 5 near the toe of well X and stages 50-52 near the middle of well Z.
Moreover, events in the shallow MC formation occurred in a few stages of well X (stages 2-5 and stage 18), while shallow events were recorded in more than half of the stages of well Z, especially near the toe of well Z.

Interestingly, the average injection pressure during the stages associated with large number of shallow events does not seem to be different from the pressure in other stages. For example, stages with a high number of microseismic events (e.g. stages 2-5 and 50-52) are not associated with higher injection pressures (with exception of stage 18), while two stages with relatively high injection pressure (e.g. stages 17 and 47) are associated with very few events. We investigated the microseismic data with other variables such as the maximum/average injection pressure and the volume of fluid and proppant injected, and no correlation was found. Hence, these shallow events seem to be more likely the result of a vertical hydraulic connection associated with pre-existing natural fractures and faults rather than anomalous hydraulic fracturing procedures.

![Figure 5: Relative depth (with respect to the Bakken formation) histograms of microseismic events by stage for Z & X wells, indicating when the events were located, and corresponding average injection pressure for each stage.](image)

Events trend ~30° with respect to $S_{H_{max}}$ - Instead of trending ~N40-50°E in the direction of $S_{H_{max}}$, as expected, the dominant trend of hypocenters is about ~30° from this direction. About 1500 microseismic events from stages 50-52 are shown in Figure 6 and fall on a consistent trend ~30° from the $S_{H_{max}}$ direction as highlighted by the blue solid line. This ~30° offset with respect to $S_{H_{max}}$ suggests that these microseismic events are probably occurring along a pre-existing natural fault, at the orientation expected for strike-slip faults. Therefore, we speculate that a well-oriented, pre-existing fault exists in the area, and the fluid injection during hydraulic stimulation of stages 50-52 activated slip along this fault.
While the blue solid line shown by microseismic events in Figure 6 represents the expected trend of a well-oriented strike-slip fault, it is possible that a conjugate strike fracture/fault exists ~60° anti-clockwise from the major fault as indicated by the blue dashed line close to the position and trend of well Y. In fact, the large population of microseismic events located parallel to wellbore Y associated with more than half of the stages may indicate the existence of a number of fractures with this trend that might have been activated during pressurization of well X and Z.

Microseismic trends and fault orientations - In Figure 7 we plot the trends of the microseismic events of the stages, omitting the distant events along wellbore Y described earlier. Since the events occur at two specific depths, the trends of the events are shown separately. The event trends were determined using a linear least square method to determine the predominant azimuth. The trends obtained from fewer than 10 events and those with fitting standard deviation greater than 40% of the maximum cluster lengths are not shown.

Several things can be observed in Figure 7. First, there is a dominant trend at N60-80°E, especially for the events located at the Bakken formation, similar to the trend seen in Figure 6. In the MC formation, besides the predominant N60-80°E trend, another major fault trend is N60-80°W, especially near the toe of wellbore Z. These N60-80°W fractures have been reported by previous studies in the Bakken area (Abbott et al., 2009; Brown, 1987; Fisher et al., 2005; Sturm and Gomez, 2009). Abbott et al. (2009) showed that the major structural lineaments on the land satellite images in the region have an orientation of N70°E and N60°W. Evidence from horizontal wellbore images drilled within the Bakken formation also showed the presence of NW striking natural fractures (Sturm and Gomez, 2009).
An Ant Track™ image (Schlumberger, 2009) of 3D seismic in the study area (Figure 8) shows the presence of a likely fault coincident with the apparent fault seen in Figure 6 as well as other faults with the overall trend seen in Figure 7. Ant Track™ is a Schlumberger seismic processing algorithm that highlights the low coherency zones in 3D with sufficiently significant spatial extent and displays them in a skeletonized manner to overlay on other seismic renderings. When fractures or faults are present, they can be identified with this method. At a regional scale, three dominant N~70°E faults sets were clearly outlined by the red dashed line, and one of them is consistent with the microseismic cluster shown in Figure 6.

Figure 8: 3D seismic Ant Track™ features with microseismic events.

Based on these observations, we propose that pre-existing natural fractures/faults, mostly striking ~ N65-80°E, exist in the study area providing conduits for upward flow responsible for the microseismic events at shallower depth.
Conjugate fractures/faults may also exist in the study area that are sub-parallel to well Y, which may explain the events that occur along its length (and the increase in pressure in well Y) in response to the pressurization of wells X and Z. We note that the predominance of points in Figure 3 and their trends in Figure 7 lie between the wells being fractured. We attribute this asymmetry of events to the influence these pre-existing natural fractures/faults, and we propose that the depletion near well Y exacerbated the pressure/fluid transmission from wells X and Z toward well Y during hydraulic fracture stimulation.

Conclusions

In this study, we integrated geomechanics with microseismic data to understand the multi-stage hydraulic fracturing stimulation in the Middle Bakken formation. We combined geological, geophysical and geomechanical data and estimated the stress state of $P_p=0.66$ psi/ft, $S_v=1.05$ psi/ft, $S_{hmin}=0.79-0.85$ psi/ft. We also analyzed microseismic events and showed three distinct patterns: First, many microseismic events are located along the middle well Y, rather than in the proximity of the stages in X and Z being stimulated. Second, most events are not associated with an elongated cloud trending in the direction of $S_{Hmax}$ as is typically observed in multi-stage hydraulic fracturing. Third, events are located at two distinct depths, close to the Middle Bakken formation and ~800 feet above in the MC formation. We believe that these unusual microseismic patterns result from fluid channeling dominated by pre-existing fractures and faults in the study area. The geomechanical model constrains the stress state in the Bakken formation could either be normal faulting or strike-slip. However, the microseismic trends suggest it is more likely to be strike-slip stress regime.

Acknowledgement

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References


Brown, D. L., 1987, Wrench-style deformation and paleostructural influence on sedimentation in and around a cratonic basin.


