Microseismic depletion delineation
Ted Dohmen¹, Jean-Pierre Blangy¹, and Jon Zhang¹

ABSTRACT
Hess Corporation performed an extensive data collection project in 2011 designed to investigate infill well spacing in the Williston Basin. Using combined microseismic and pressure data collected from six observation wells and the original depleted horizontal wellbore, we identified the potential for using microseismic data to monitor the extent of depletion in unconventional reservoirs. We propose broader use of this surveillance process, which we call microseismic depletion delineation. We recommend pumping pressurized fluids into, or in the vicinity of, a well that has been on production while simultaneously monitoring for microseismic events as a means to discover the optimal spacing for development wells. Our measurements revealed that depletion over a two-and-a-half year period puts the reservoir in a critically stressed state. By repressurizing the depleted wellbore to a level below the minimum horizontal stress, we promoted shear events that revealed the location of the connected, permeable fractures that delineate the depleted part of the subsurface. We considered alternative interpretations for the nonuniform depletion that we mapped along the length of this Middle Bakken well, including completion fluid diversion by faults and wellbore sloughing occluding the production string. We conclude that this procedure has application to shale plays in much the same way that 4D seismic monitoring is used as a production surveillance tool for conventional reservoirs.

Introduction
Microseismic analysis is widely applied by the oil and gas industry as a tool in the monitoring of completions during hydraulic fracturing. Determining locations from microseismic events recorded during stimulation can provide important constraints on the far-field dimensions of an active fracture treatment. Processing efforts have focused on accurately locating microseismic events by building increasingly precise velocity and depth models (Li et al., 2012, 2013). Most publications on microseismic technology involve improving the processing of data for better event locations or describing workflows for visualizing and modeling hydraulic fractures using the event distributions. After the events are accurately located, geophysicists attempt to measure the height, length, and width of the “disturbed” zone around each fracture stage. These measurements can be used as important constraints for engineers performing fracture modeling.

A successful fracture model provides insights into the fracture half-length, fracture conductivity, and the reservoir system permeability used to predict resource volumes and to estimate ultimate recoveries. More recently, efforts to perform moment tensor inversion show promise for constraining the preexisting natural fracture networks that may, in places, significantly affect well performance (Urbancic et al., 2013). In all cases, current efforts provide input to reservoir simulation models that predict future outcomes with potentially widely varying results due to large inherent uncertainties (Cipolla et al., 2011). By contrast, what we propose is a timely direct measurement that may be used to check the progress of reservoir depletion and to provide important additional constraints on reservoir simulation models. This is supported by integrating stress and fracture characterization from diagnostic fracture injection tests (DFITs), Mohr-Coulomb failure analysis, and in situ reservoir pressure data.

Our observation of the spatial distribution of microseismic events has led us to believe that reservoir depletion tends to occur nonuniformly in unconventional reservoirs. We will show some clues from a field experiment carried out in the Bakken that support

¹Hess Corporation, Houston, Texas, USA. E-mail: tdohmen@hess.com; jpblangy@hess.com; jzhang@hess.com.
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this, and we will explain the reasons for nonuniform depletion. We show through our pilot study that the hydraulic fractures induced during the completion process interact with natural faults in the subsurface to create a complex network of fractures that may affect the efficiency of completing in zone.

This experiment provides a unique insight into the shape of the depleted zone and its influence in developing Middle Bakken resources. By analyzing the extent of the depleted zone outline, we can now propose a series of efficiently placed infill well locations at a minimum distance from the original producer. We leverage microseismic analysis as a tool to optimize the spacing of development wells. Our objective is to infill drill at the minimum distance required to maximize fracture contact in-zone, near the infill wells, and avoid significant overlap into previously depleted zones. Thus, a new application for microseismic monitoring is envisioned, in which one would pressure up a producing well to measure its associated area of depletion prior to planning the spacing of subsequent development wells or adjusting strategies for hydraulic fracturing.

**Acquisition and processing of microseismic measurements**

**The infill pilot setting**

Our study area is located in the Williston Basin of North Dakota. Two infill horizontal wells H2 and H3 (Figure 1) were drilled south–north parallel to an existing producing well, the H1 well, to test for optimal well spacing by looking for interference during and after hydraulic fracturing of the infill wells. All wells are located in the Middle Bakken Formation, a Mississippian-Devonian reservoir at an approximately 3050 m (10,000 ft) depth. The reservoir is a calcitic/dolomitic siltstone between the Upper and Lower Bakken Shales, which are the source rocks for the play. The structure dips at approximately 1° toward the south. The infill horizontal wells were drilled approximately 150 m (500 ft) away from the central producer (Figure 1).

Hess designed the microseismic field experiment to monitor the hydraulic fracturing of the H2 and H3 infill horizontal wells, which took place in 2011. The experiment was specifically designed to observe the interaction of the fractures with the preexisting horizontal well (H1), which had been in production for about

![Figure 1](https://example.com/figure1.png)

**Figure 1.** Base map and side view of the original horizontal production well (H1), two horizontal infill wells (H2 and H3), and six vertical observation wells (green triangles in the map view). Microseismic geophone arrays are the green triangles in the side view. In the two infill wells, completion stages with blue dots used ball-actuated sliding sleeves, and stages with red stars used pump-down plug-and-perf completions.
two-and-a-half years. The H1 well was shut in for the duration of the experiment and instrumented with a downhole pressure gauge (Figure 2). Six vertical wells were drilled to below the reservoir depth to act as observation boreholes. They were perforated in the Middle Bakken to that DFTTs could be performed in the zone of interest. They were fitted with pressure memory gauges capped by a bridge plug to record pressure variations prior to, and during, the stimulation. Each observation well was also instrumented with a 40-level, 580-m (1900 ft-) long geophone array to monitor microseismic events induced by the stimulation of the H3 and H2 infill wells. A more detailed description of the experiment may be found in Dohmen et al. (2013). Figure 2 shows the power of our proposed technique by contrasting the reservoir simulator’s prediction of depletion with the microseismic depletion delineation (MDD) measurement. The reservoir simulator will naturally ascribe total production evenly to all the fractures placed in the well (Figure 2a), whereas the actual measurement has the potential to reveal the true nature of depletion in the subsurface (Figure 2b).

Data processing

Microseismic data were recorded successfully from all stations in the observation wells for the duration of the H3 and H2 completions. Event locations were originally computed using a single anisotropic velocity model for P-wave velocities that was calibrated by perforation shots to establish entry points for completion fluids in the fracture stages from the heel section of each infill well. Event locations were computed from multiwell P-wave arrival times. The number of instruments and the relative proximity of the observing wells allowed for computation of accurate event locations. We estimate the velocity model uncertainty of the original processing at \( \pm 15 \) m (50 ft), given that observation distances for most events were less than 610 m (2000 ft).

Reprocessing of selected stages was performed in 2013 to validate the depletion effect noticed in stage 4 of H3 completion (the first infill well to be completed) and for better understanding of the shallow points located above the reservoir in the first five stages of the H3 completion. This reprocessing involved multiwell relocation using P- and S-wave arrivals. We compare results in the Discussion section of this paper.

Geomechanics

In situ stress and pore pressure

In porous media, the effective stresses control the mechanical behavior and failure of rocks. We calculate the effective stress by using Biot’s effective law (Biot, 1941):

\[
\sigma^' = \sigma - \alpha p_p,
\]

where \( \sigma \) and \( \sigma^' \) are the total and effective stresses, respectively; \( p_p \) is the pore pressure; and \( \alpha \) is Biot’s coefficient.

Core tests described by Havens and Batzle (2011) and Havens (2012) show that \( \alpha \) is in the range of 0.3–0.75 for the Middle Bakken and indicates that \( \alpha \) decreases with axial stress and confining pressure. We assume that the average value of Biot’s coefficient is \( \alpha = 0.5 \) based on our log-based calculation in the study area and the study of Havens (2012).

It is assumed that the in situ stress consists of three principal stress components: vertical (overburden) stress, minimum horizontal stress, and maximum horizontal stress. The overburden stress \( (\sigma_V) \) is obtained by integrating the bulk density logs. We estimate the overburden gradient to be approximately 1.048 psi/ft in the study area.

Pore pressure depletion during oil production results in a decrease in the minimum and maximum horizontal stresses (e.g., Teufel et al., 1991; Alberty and McLean, 2001; Lang et al., 2011). In a depleted reservoir, the decrease in the minimum stress is related to the change in...
pore pressure (Engelder and Fischer, 1994). Our minimum horizontal stress prior to depletion is obtained from the fracture closure pressure in DFIT data performed in observation wells. The minimum horizontal stress in the depleted case is estimated from the following equation:

\[ \sigma_h = k(\sigma_v - \alpha p_p) + \alpha p_p, \]

where \( \sigma_h \) is the minimum horizontal stress, \( p_p \) is the reservoir pressure, and \( k \) is the ratio of the minimum and maximum effective stresses, or \( k = (\sigma_h - \alpha p_p) / (\sigma_v - \alpha p_p) \). Hess has performed numerous DFIT measurements in the Middle Bakken that constrain this ratio, providing us with a means to estimate \( \sigma_h \) from the reservoir pressure. We observe that \( k \) decreases gradually with reservoir depletion, as shown in Figure 3.

The reservoir formation pressure measured by the pressure gauge of the produced H1 was 2515 psi prior to the infill completions. The undepleted formation pressure measured in three of the observation wells (refer to Figure 2b) and from DFIT data is greater than 6800 psi. Historical production from the H1 well had a bottom-hole pressure of 6,292 psi for the Middle Bakken reservoir after several days of production. Therefore, it is reasonable to assume that the original, undepleted reservoir pressure was in the range of 6800–7000 psi. The stabilized reading of \( p_p \) was 2515 psi in the H1 well after two-and-a-half years of production, specified at an equivalent depth of 10,000 ft. This means that the reservoir pressure was depleted by 4285 psi. After this depletion, the reservoir pressure is much lower than the hydrostatic pressure of 4650 psi, as shown in Figure 4.

The maximum horizontal stress can be calculated from the fracture breakdown pressure (e.g., Haimson and Fairhurst, 1967) or from wellbore breakout (e.g., Li and Purdy, 2010). We estimate that the maximum horizontal stress magnitude \( \sigma_H \) is 9400 psi using the pressure-gauge measured pore pressure and the DFIT measured minimum horizontal stress based on Zhang et al. (2008). The maximum horizontal stress is calibrated from the fracture breakdown pressure in the DFIT data based on Haimson and Fairhurst (1967) and Zhang (2011). The estimated maximum horizontal stress is consistent with regional results for the Bakken formation reported by Wang and Zeng (2011). We note that previous Hess experience with microseismic monitoring of hydraulic fractures in undepleted Middle Bakken shows mostly diffuse clouds rather than distinct lineations (Hayles et al., 2011), leading us to believe that there is not a significant difference in the two horizontal stress magnitudes.

Figure 4 presents the in situ stress profiles prior to depletion and after 4285 psi of depletion in the Middle Bakken oil reservoir at an equivalent depth of 3050 m (10,000 ft). Pore pressure is overpressured in the Bakken and the deeper Three Forks formation. From DFIT analysis and pressure gauge readings in the observation wells, the pore pressure gradient (prior to depletion) varies in a range of 0.61–0.7 psi/ft in the Bakken formation and 0.72–0.73 psi/ft in the Three Forks formation. The DFIT-measured minimum horizontal stress gradient ranges from 0.71 to 0.79 psi/ft.
in the Bakken and from 0.78 to 0.83 psi/ft in the Three Forks formation. Figure 4 shows that the pore pressures obtained from DFITs (blue circles) and measured from the pressure gauges (yellow dots) match very well. This indicates that the minimum horizontal stress measured from the closure pressures in DFITs should be reliable. Therefore, we conclude that the most likely pore pressure and in situ stress gradients prior to depletion in the Middle Bakken reservoir of well H1 are the following: $p_H = 0.68$ psi/ft, $\sigma_H = 0.786$ psi/ft, $\sigma_{HF} = 0.94$ psi/ft, and $\sigma_V = 1.048$ psi/ft.

Shear failure analysis

For faulted and hydraulically fractured rocks, the Mohr-Coulomb failure criterion can be simplified by assuming a negligible cohesion of the faults or fractures:

$$\tau_f = \mu_f \sigma_n', \quad (3)$$

where $\tau_f$ is the shear stress in the fractures, $\mu_f$ is the friction coefficient of the fractures, and $\sigma_n'$ is the effective normal stress resolved from components of the vertical effective stress ($\sigma_v'$), the maximum horizontal effective stress ($\sigma_H$), and the minimum horizontal effective stress ($\sigma_H$).

Equation 3 characterizes the condition for shear failure along the fractures. For the Middle Bakken, which consists of approximately 50% calcite, 40% quartz, and 10% clay, we estimate that $\mu_f = 0.5$ (Ikari et al., 2010; Amendt et al., 2013).

Our Mohr circle analysis describes a two-step mechanical response of the reservoir through time, as shown in Figure 5. Step 1 is depletion, during which Mohr's circle expands and moves to the right. Step 2 is injection, during which it moves to the left while keeping its size unchanged during repressurization. It should be noted that if the Mohr circle touches the Mohr-Coulomb failure envelope, it signifies the initiation of shear failure by slip on optimally oriented fractures. The number of fracture orientations subject to shear failure increases as the Mohr circle moves farther to the left.

The pore pressure drop accompanying two-and-a-half years of depletion is expected to diffuse into the surrounding formation on the order of meters to tens of meters for permeabilities in the micro-Darcy range, causing a localized drop in the total minimum stress. Meanwhile, the increase in pore pressure during injection occurs over a time period of minutes to hours and will not diffuse significantly into the matrix. We infer that the points we collect in our MDD outline (i.e., points that were too distant to be part of a propagating hydrofrac) were caused by delivering elevated pore pressure through the borehole to the connected, permeable system of fractures and faults that contributed to production. This reduced their effective normal stress, causing the fractures to shear and reveal their location by generating microseismic events.

Observations of shear failures

During the fourth stage of stimulating the first infill well (H3), microseismic events rapidly traveled southward along the neighboring H1 borehole. These points appeared at considerable distances of up to 2740 m (9,000 ft) from the ports open for that stage. The microseismic events outlined an elongated gourd-shaped area about 55 acres in size that lies mostly along the southern two-thirds of the H1 well (Figure 2b). Subsequent stages throughout the rest of the H3 well’s completion also produced points at distances too great to be part of the newly induced fractures (assuming reasonable fracture propagation speeds of 0.1 to 0.4 ft/s for the duration of each frac). The map in Figure 2b, which includes these points, shows an area of about 120 acres, nominally about 240 m (800 ft) wide, lying mostly centered along the southern two-thirds of the wellbore. It is interesting that this depletion “footprint” does not cover the northern portion of this well as expected, and so we compare it to the pressures from the observation well gauges.

The map in Figure 2b shows the formation pressures in the six vertical observation wells, all of which reached equilibrium in the weeks before the hydraulic fracturing treatment was done. We take them as confirmation of the extent of the H1 well’s depletion. Note that all three wells located within the depletion

![Figure 5. Mohr circle representation of in situ effective stress showing depletion and injection in the Middle Bakken reservoir at a depth of 10,000 ft, and their relationships with the Mohr-Coulomb shear failure envelope of the fractured formation (red line). (a) Reservoir with depletion (by 4285 psi). (b) Depleted reservoir with injection of 1200 psi.](https://pubs.geoscienceworld.org/interpretation/article-pdf/2/3/SG1/3006725/INT-2013-0164.pdf)
cloud, as determined by microseismic analysis, show varying degrees of partial depletion, while the three wells outside the cloud remain at background formation pressure. Note also that the northernmost well, which remains at a background formation pressure of 6843 psi, lies quite close to the H1 wellbore, yet it is outside the microseismically delineated extent of depletion. This would not be the prediction from a reservoir model with evenly distributed production, and it shows the importance of making the measurement in the field (Figure 2). The size and shape of this event cloud (Figure 2b) is an important constraint for reservoir simulation because it represents the extent of induced and natural fractures that have contributed to production.

Figure 6a shows the relationship between the downhole pressure in the H1 well and the time of injection, along with a histogram of the number of microseismic events. The pressure-time plot in Figure 6a clearly shows that when the distant microseismic events first occurred, the H1 well’s pressure remained below that needed to create new tensile fractures in undepleted rock. In other words, the injection caused slip on existing depleted fractures connected to the depleted well. If any events were related to tensile fracturing, they must also have been within the limits of depletion. The Mohr’s circle plots (Figure 5) and our analysis of observation well pressures supports this conclusion.

Discussion

Geomechanical model parameter selection

All the parameters needed to describe Mohr’s circles are listed in Table 1. Of these, we are most confident in the values for \( \sigma_V \), the pore pressure in depleted and undepleted cases, and the value of \( \sigma_h \) in the undepleted case. These come from measurements in the wells and are well constrained. The other parameters come from

![Figure 6](image)

**Figure 6.** Depletion delineation using all distant events from well H3 stimulations: (a) Record of H-1 well downhole pressures during all the H-3 completions, and microseismic event times (histograms). Pressures in the well stayed below the threshold required to generate new tensile fractures indicated by the red zone, bracketed by estimates of the minimum stress (7860 psi) from DFITs on the low side, and fracture closure stress (8500 psi) from shut-in pressures on the high side. From this, we conclude that these events are shear events occurring within the connected permeable system depleted by earlier production of the H-1 well. (b) Side view of the depleted zone.
estimates based on published literature or are calculated as shown in Table 1. We expect that the range of reasonable values for most of the calculated parameters is relatively narrow; however, of most concern for our model is the selection of Biot’s coefficient, \( \alpha \) because it affects the placement of all Mohr’s circles on the abscissa.

We choose \( \alpha = 0.5 \) as a reasonable average for the Middle Bakken reservoir shown by Havens (2012) based on core test data. We recognize that there is a considerable range of values from 0.30 to 0.75 that may be appropriate and that our model is sensitive to the choice of this parameter. In fact, the range of \( \alpha \) may be highly variable according to the layer properties of the Middle Bakken reservoir (Havens, 2012). We note at this stage that the numbers used to constrain our model listed in Table 1 are consistent with the appearance of shear events in depleted rock after elevating pressure in the borehole by 1200 psi. This is the condition shown by the Mohr’s circle encountering the shear line (Figure 5b). The consequences of using a higher value for \( \alpha \) and how it affects our interpretation can be anticipated by considering a hypothetical controlled experiment.

**Proposed method**

Where depletion delineation is the objective, a controlled experiment could be run by pumping into a depleted well while monitoring for microseismic events. As pressure rises in the system of permeability connected to the borehole, we should expect a sequence of microseismic events as predicted by our geomechanical model shown in Figure 7.

Starting from the depleted reservoir pressure of 2515 psi, as pressures rise, the effective normal stress will gradually decrease on fractures connected to the borehole, eventually leading to shear. We should expect to first see shear events associated with depleted fractures as the pressure rises above the critical stress condition, here 3800 psi. These shear events should be followed by events associated with extending tensile fractures in the depleted reservoir once pressures exceed \( \sigma_h \) for the depleted reservoir, here 5195 psi. As pressure continues to rise above the original pore pressure, shearing of undepleted fractures could begin. These fractures might be encountered by the extending tensile fractures, and the level of pressure predicted to cause these to slip would be highly related to the choice for \( \alpha \), shown by the two lines in Figure 7 at 7100 and 7800 psi. Finally, tensile fracturing of undepleted rock around the perimeter of the depleted area could occur once pressure in the fractures rises above the initial state \( \sigma_h \), here 7860 psi.

The identification of events related to depletion and how well they can be separated from events occurring in the adjacent, undepleted reservoir will depend on how rapidly the pressure is allowed to rise and on Biot’s coefficient. In Figure 7, we show a range for the onset of shear in undepleted rock between 7100 and 7800 psi depending on Biot’s coefficient \( \alpha \). A smaller value for \( \alpha \) delays the onset.

We note that, in our actual experiment, the pressures encountered in the H1 well were below the threshold for tensile fractures to form in undepleted rock (Figure 6a). Based on the difference between pumping pressures monitored during the H3 well fracture and the pressure monitored in the H1 well, we expect about 1000 to 2000 psi of pressure drop through the fractures. Applying a similar pressure drop to the fractures pressurized from the wellbore, we conclude that the events we saw were most likely confined to the depleted section.
Interpretation of observations

We interpret the extent of the events identified during stage 4 pumping of the H3 well as a depletion footprint because they first appeared when the injection pressures were only 3800 psi. These pressures were too low to cause shear in the undepleted formation. Taking the more complete point set shown in Figure 2b to represent depletion is our interpretation, but we note several lines of evidence to support this claim:

- First, we note the cloud of candidate points collected from all H3 stages largely overlays the stage 4 points, which lie mostly along the southern two-thirds of the borehole.

- Second, we note conformance of the depletion outline with build-up pressures recorded in the six observation wells. Referring to Figure 2b, three of the wells showing partial depletion all lie within the depletion outline. The other three wells are within 100 psi of original undepleted pressure, and these lay outside the outline. One of these (Well O-2-32) lies close to the H1 wellbore (within 280 ft), where we might expect to have some pressure depletion for a uniformly depleted case.

- Third, we point out that the cumulative probability of initial production from this well lies at about the 70th percentile of other Hess wells with 10 stages. This is similar to the extent of the interpreted depletion cloud relative to the length of the well, a fact that invites further interpretation.

- Finally, we note that the H1 oil production rate resumed unchanged (Figure 8) after waiting the better part of a year while the infill wells H2 and H3 were completed and produced. If significant additional fractures had formed, we would expect uplift in the oil production rate.

Using this mapped outline as an indicator of depletion, we considered several possibilities for why it does not appear along the northern third of the H1 borehole:

- uneven drawdown
- pumping parameters different for stages near the toe
- ineffective fractures near the toe of the well where fluids were diverted by faults

Figure 8. Cumulative oil and water production from the H1 well and daily oil rate. The period of shut-in time of the H1 well during the fracturing and production of offset wells H2 and H3 is removed from the plot at the dashed line.

Figure 9. Microseismic event depth histograms normalized by the number of points per stage, showing the height above the Middle Bakken Formation (red line) for events from the H3 infill well completion. Stages 1–5 are reprocessed; the rest are original event locations. Stages 1–3, 11, and 18 show evidence of hydraulic fracture interaction with shallower layers.
• Upper Bakken Shale strikes may have occluded production.

The first two points can be eliminated because we do not believe that draw-down varies significantly along the length of our laterals in this play because permeability is relatively low and the pumped volumes varied less than 15% for all stages. The two remaining alternatives are discussed in detail below.

**Interpretation 1: Preexisting faults**

The lack of a depletion footprint in the northern portion of the well might be related to diverting of hydraulic fluids whenever small faults are present. See Yang et al. (2013) for more information about fault interaction during fracturing. Microseismic data from this infill experiment show several shallow event clouds (Figures 9 and 10). We believe that ineffective fractures are placed in the Middle Bakken whenever energy is diverted by fracture corridors or faults that connect to shallower layers.

Depth histograms of events plotted by stage (Figure 9) support the hypothesis that flow channeling along preexisting fractures or faults connected to shallow layers dominates the toe-side stages of our wells in this area. The depth histograms do not represent the complete story; they show which stages lead to shallow events but not where those events were occurring. There is a distinct depth bias toward microseismic event activity above the Bakken Formation when shallow points occur.

**Figure 10.** Reprocessed microseismic event locations indicate connections to shallow intervals and a progression of events back to the zone of interest in successive stages. Colored squares along the borehole represent the locations of packers separating fracture stages. Because the stage 2 interval includes an identified fault from geosteering, it seems likely that faults may be limiting the effectiveness of Middle Bakken completions when they are present.

**Figure 11.** Cross section showing the location of shallow microseismic events from H3 completion stages 2–5, relative to well log data, gamma ray (spindle), and formation tops. It is important to understand the height of these points above the lateral because Madison Group formations, including the Lodgepole and overlying Mission Canyon, are potential sources of hydrogen sulfide and water.
Figures 10 and 11 show connections are undeniably established to shallow units during some of the fractures. At best, this diverts energy and limits proppant placement in the zone of interest. In the worst case, the diverted fractures create pathways for unwanted fluids (such as hydrogen sulfide and water) during oil production, requiring costly separation and disposal. In either case, it would be advantageous to consider mitigation schemes. For example, we might build “sacrificial” stages into the completion string while the well is drilled. We could then use geosteering and 3D seismic surveys to find the stages with faults (Figure 12) and, when completed, skip these stages.

**Interpretation 2: Wellbore sloughing**

Reprocessed event locations suggest another possible explanation for the outline of the depletion footprint. Referring to Figure 13, the reprocessed version of the MDD cloud (the orange outline in Figure 13b) stops south of the original version of the same data (the yellow outline in Figure 13a) and also south of the Upper Bakken Shale strikes logged in the original well as shown by the gamma-ray log “spindle” in the figure. We should consider the possibility that the Upper Bakken Shale sloughed into the borehole during production, occluding the communication of upstream ports into the well and keeping the toe-side stages from depleting properly. A Hess study, showing that wells with fracture stages that initiate higher in the section yield wells with a higher water cut, drives our understanding of the consequences of encountering Upper Bakken Shale. It is Hess Bakken Team’s current practice to skip stages containing Upper Bakken Shale strikes for this reason.

In summary, we offer two explanations for the uneven depletion observed along the original H1 wellbore: natural faults or wellbore sloughing. We believe that by adjusting completions in the vicinity of faults or shale

![Figure 12. Geosteering result from the H3 infill well showing a 2.5–3 m (8–10 ft) fault in stage 2, where shallow events first appear. The smaller “potential” fault on this display is also marked by a cluster of shallow points occurring in stage 11. Courtesy of P. Niemeyer, Hess Bakken Team.](image-url)
strikes, we can improve the efficiency of stimulations in
the zone of interest, enhance oil recovery, and reduce
water production.

Summary

This experiment provided a unique opportunity to
visualize the shape of the depleted zone around a pro-
ducing Middle Bakken well and to understand its influ-
ence in developing Bakken resources. By analyzing
the outline of the depleted zone, we can optimize the spac-
ing of development wells. Our objective is to infill drill
at the minimum distance required to maximize fracture
contact in-zone near the infill wells and yet avoid signifi-
cant overlap with previously depleted zones. This new
application for microseismic monitoring involves pres-
suring up a producing well to provoke shear events that
indicate its actual area of depletion prior to planning
subsequent development wells and executing field-wide
strategies for hydraulic fracturing.

We call it MDD, and we foresee its significance for
field surveillance in unconventional plays in much the
same way that 4D seismic monitoring is employed
for monitoring the depletion of conventional reservoirs.
The method measures the extent of depletion, can be
acquired quickly when needed, and provides an impor-
tant constraint for reservoir simulation and fracture
modeling. Whereas normal microseismic monitoring
of hydraulic fracturing will provide constraints on the
entire extent of propped and unpropped fractures,
using the proposed technique should help describe
the contributing “effective” portion of the fractures.
Knowing the extent of the contributing induced and
natural fractures is important to understanding the per-
meability of the surrounding unpropped matrix. Mapping
the extent of the de-
pleted zone is critical for simulation-based calculations of reserves, and it
is directly useful for making well-spac-
ing decisions.

Conclusions

In our pilot field test, hydraulic frac-
turing locally supplied increased fluid
pressure to a nearby produced well that
was shut-in for the duration of this
experiment. The wellbore was instru-
mented with a pressure gauge that
showed elevated fluid pressure from
one of the neighboring fractures was
being delivered to the entire system of
connected permeability, including the
wellbore and its surrounding depleted
network of fractures. This caused nu-
merous microseismic events to appear
along the length of the old wellbore
within a matter of hours and at distances
up to 2740 m (9000 ft) from the open
fracture port. The events are interpreted
to indicate shear slip on depleted frac-
tures, but not newly generated fractures
because pressures remained below the
original minimum stress. The outline
of these events represents the extent
of the connected, contributing fracture
network, which has direct implications
for optimizing completion design by
avoiding zones with faults or shale
strikes.

Whatever mitigation scheme we em-
ploy, our interpretation clearly suggests
that MDD has the potential to assess
production efficiency. Being able to
check and adjust procedures is funda-
mental to engineering-driven plays such
as the Bakken. 

Figure 13. Comparison of interpreted MDD maps from two processed versions
of H3 completion stages 4 and 5 displayed along with all points from stages 2–5.
The interpreted depletion outline is constructed from deep points in the zone.
(a) The original processed points with MDD outline in yellow and (b) the reproc-
essed points with MDD outline in orange. This suggests two alternative hypoth-
eses to explain the northern limit of the depletion outline: (1) Faults diverted
fracture fluids in the northern stages of the original well or (2) shale sloughing
occluded the borehole where Upper Bakken Shale is encountered in the well.
The gamma ray is displayed as a spindle on the H1 well with the thin portion
(high gamma ray) showing where Upper Bakken Shale was encountered. Red
lines outline square-mile section boundaries.
mic becomes affordable, it could become a full-field development tool for unconventional plays. One could, for instance, use it to monitor the original completions, then test depletion with MDD, design the infill wells, watch their completions, test depletion again in a few years, and so forth. This interpretation exercise leads us to recognize that a greater effort needs to be placed on developing inexpensive microseismic acquisition methods and on better geophysics for velocity modeling and event location.

Another benefit of mapping depletion with MDD is related to infill drilling near an original well after a few years of production. This is a typical situation in which a single well is drilled and produced to hold acreage. In many of these cases, subsequently drilled wells produce less than the original well, often due to how the new fractures form. Lowered formation pressure in depleted zones also lowers the total minimum stress, so that fractures placed in the subsequent wells tend to form one-sided in the direction of nearby depletion. Using the measured depletion outline as a constraint in reservoir simulation should help with anticipating the pore pressure and estimating the halo of the minimum stress for planning offset well completions.

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Biographies and photographs of the authors are not available.