

URTeC: 2461621

Determining Maximum Horizontal Stress With Microseismic Focal Mechanisms – Case Studies in the Marcellus, Eagle Ford, Wolfcamp Alireza Agharazi*, MicroSeismic Inc.

Copyright 2016, Unconventional Resources Technology Conference (URTeC) DOI 10.15530-urtec-2016-2461624

This paper was prepared for presentation at the Unconventional Resources Technology Conference held in San Antonio, Texas, USA, 1-3 August 2016.

The URTeC Technical Program Committee accepted this presentation on the basis of information contained in an abstract submitted by the author(s). The contents of this paper have not been reviewed by URTeC and URTeC does not warrant the accuracy, reliability, or timeliness of any information herein. All information is the responsibility of, and, is subject to corrections by the author(s). Any person or entity that relies on any information obtained from this paper does so at their own risk. The information herein does not necessarily reflect any position of URTeC. Any reproduction, distribution, or storage of any part of this paper without the written consent of URTeC.

Summary

The field stress parameters, direction and magnitude of horizontal and vertical stresses, are important factors in the design of hydraulic fracturing treatments in unconventional reservoirs. It is well understood that an induced hydraulic fracture propagates in the direction of maximum horizontal stress, suggesting that horizontal wells must be perpendicular to this direction for efficient well-reservoir hydraulic connection during treatment and production. The horizontal stress anisotropy also affects the optimum well spacing and stage length.

Numerical studies show that in naturally fractured reservoirs, higher horizontal stress anisotropy promotes more planar stimulation patterns that extend farther away from the well. For the same treatment parameters, low horizontal stress anisotropy leads to near-wellbore complexities. The magnitude of stresses also controls the minimum horsepower requirement for treatment. The bottomhole injection pressure must exceed and be maintained above the minimum reservoir stress for a hydraulic fracture to initiate and propagate through the formation.

A relatively accurate estimate of the vertical stress magnitude can always be obtained by integrating the density logs to the reservoir depth. The minimum horizontal stress magnitude can also be determined from well tests, such as a mini-frac test or diagnostic fracture injection test. There is, however, no direct and easy way to measure the magnitude of maximum horizontal stress (S_{Hmax}) at the reservoir depth. Wellbore breakout analysis is commonly performed to constrain the S_{Hmax} magnitude based on observed wellbore breakouts. The result of such analysis, however, is more representative of the well-scale stresses rather than the reservoir-scale stress state, unless several wells within the same region can be studied simultaneously.

In this paper, we present a new methodology to estimate the direction and magnitude of maximum horizontal stress using microseismic focal mechanisms. The moment tensor inversion technique is applied to establish a moment tensor for all acquired microseismic events. The event focal mechanism and fracture orientation is determined by the fault plane solution of the moment tensor. Each focal mechanism is treated as an independent field experiment by which we can back-calculate the magnitude of S_{Hmax} . The field S_{Hmax} magnitude is then determined by analyzing all calculated values for all qualified events. The described methodology is used to estimate field S_{Hmax} for five cases in three different formations; the Marcellus, Eagle Ford, and Wolfcamp. Using the known orientation of fractures and full-field stress tensor, the minimum failure pressure is calculated. An example of this analysis is provided for one of the studied Marcellus cases.

Introduction

The state of stress in a formation is characterized by three principal stress directions and magnitudes. The vertical stress is commonly assumed as one of the principal stresses whose magnitude is equivalent to the weight of overburden rock, calculated from density logs. The direction and magnitudes of horizontal stresses are more challenging to determine. Wellbore breakout pattern or tensile fracture orientation in vertical wells are usually observed to determine the direction of maximum and minimum horizontal stresses (S_{Hmax} and S_{hmin}). It is also well understood that a hydraulic fracture initiated from a horizontal well propagates horizontally in the S_{Hmax} direction.

This direction can usually be identified by microseismic monitoring, so an estimate of S_{Hmax} direction can be obtained.

While there are several techniques to measure the S_{hmin} magnitude, such as a mini-frac test, leakoff test, and diagnostic fracture injection test (DFIT), there is no direct way to measure S_{Hmax} magnitude. The back-analysis of borehole breakouts using the Kirsch equations for stresses around a circular hole can help to constrain horizontal stresses and to estimate S_{Hmax} magnitude, if S_{hmin} magnitude is known (Zoback 2010). The same set of equations can be used to back-calculate S_{Hmax} magnitude from hydraulic fracturing of un-cased and un-cemented wells (Zoback 2010, Amadei and Stephansson 1997). However, this method is not applicable in most horizontal wells drilled in unconventional reservoirs, mainly because these wells commonly have casing and are cemented. Sinha et al. (2008) reported the application of borehole sonic data for estimation of horizontal stresses. The stress inversion technique, frequently used by seismologists to estimate field stress state from earthquake focal mechanisms, has also been applied to microseismic focal mechanisms to estimate formation stresses (Neuhaus et al. 2012, Sasaki and Kaieda 2002). This method, however, may not produce reliable solutions in many cases because of noisy microseismic data and the inherent ambiguity in the fault plane solution (Agharazi 2016).

A reliable knowledge of full stress state (i.e., three principal stress directions and magnitudes) is necessary for many routine engineering designs and analyses, such as wellbore stability analysis, geomechanical modeling, hydraulic fracturing simulation and treatment design. It is well understood that the horizontal wells must be drilled perpendicular to S_{Hmax} direction for an efficient well-to-reservoir hydraulic connection during stimulation and production. The difference between S_{Hmax} and S_{hmin} magnitudes (i.e., horizontal stress anisotropy) has a significant effect on the stimulation pattern and must be considered for efficient well spacing and stage length design.

Numerical simulations of hydraulic fracturing in naturally fractured reservoirs indicate that higher horizontal stress anisotropies promote more planar stimulation patterns that grow away from the treatment well, whereas, lower horizontal stress anisotropies cause less laterally extended stimulation patters and more complexities close to the well (Zhang et al. 2013).

By knowing all field stress components, the minimum failure pressure on natural fractures can be estimated if orientation of natural fractures is known. This is a valuable parameter that can be used to optimize the treatment parameters, such as fluid viscosity and pump time, to improve the stimulation by activating natural fractures.

In this paper, we present a new methodology for determination of S_{Hmax} direction and magnitude from microseismic focal mechanisms. For each microseismic event, a moment tensor is determined by using the inversion technique. The eigenvectors of the moment tensor are then calculated to determine the event focal mechanism, including slip plane (fracture) orientation and slip direction. The horizontal stress direction is then determined based on the focal mechanisms that meet a certain criterion.

By assuming that a fracture slips in the direction of maximum shear stress acting on the fracture plane, a linear relationship is formed between S_{Hmax} and S_{hmin} magnitudes for each event. After obtaining the field S_{hmin} magnitude, for example by a mini-frac test, the S_{Hmax} magnitude is calculated for each qualifying fracture. The field S_{Hmax} magnitude is then determined by interpreting the calculated values for all events. This methodology is used to calculate S_{Hmax} direction and magnitude for five cases in the Marcellus, Wolfcamp, and Eagle Ford plays. The minimum failure pressure required to stimulate natural fractures is also calculated for one of the Marcellus cases.

Seismic Moment Tensor and Focal Mechanism

The seismic moment tensor is a mathematical description of deformation mechanisms in the immediate vicinity of a seismic source. It characterizes the seismic event magnitude, failure mode (e.g., shear, tensile), and fracture orientation. The seismic moment tensor is a second-order tensor with nine components shown by a 6×6 matrix as follows:

$$M = M_o \begin{bmatrix} M_{11} & M_{12} & M_{13} \\ M_{21} & M_{22} & M_{23} \\ M_{31} & M_{32} & M_{33} \end{bmatrix}$$
(1)

where M_o is the seismic moment and M_{ij} components represent force couples composed of opposing unit forces pointing in the i-direction, separated by an infinitesimal distance in the j-direction. For angular momentum

conservation, the condition $M_{ij} = M_{ji}$ should be satisfied, so the moment tensor is symmetric with just six independent components. A particularly simple moment tensor is the so-called double couple (DC), which describes the radiation pattern associated with a pure slip on a fracture plane. The DC moment tensor is represented by two equal, non-zero, off-diagonal components.

The focal mechanism of a seismic event can be determined from eigenvectors of the event's moment tensor. The three orthogonal eigenvectors of the moment tensor denote a pressure axis (P), a tensile axis (T), and a null axis (N). The slip (fracture) plane is oriented at 45° from the T- and P-axes and contains the N-axis, as shown in Figure 1 (Cronin 2010). The slip vector on the plane (rake vector) can then be determined using a set of equations relating the slip vector to the fracture normal vector and the moment tensor eigenvectors. More details can be found in Jost and Herrmann (1989).

The focal mechanism provides three important parameters; fracture strike, dip, and rake angle. The fracture strike is measured clockwise from north, ranging from 0° to 360° , with the fracture plane dipping to the right when looking along the strike direction. The dip is measured from horizontal and varies from 0° to 90°. The slip (or rake) vector represents the slip direction of hanging wall relative to foot wall. The rake angle is the angle between the strike direction and the rake vector. It measured from 0° to 180° when changes counterclockwise from strike, and from 0° to -180° when measured clockwise from strike (when viewed from the hanging wall side) (Figure 2).

For microseismicity induced by hydraulic fracturing, an inversion approach is used to find a moment tensor corresponding to each recorded event. In this technique, a best-fit solution is sought by minimizing a residual function, usually a least-squares function, for all wave patterns recorded for a given event by different receivers. Details of moment tensor inversion techniques can be found in Jost and Herrmann (1989) and Dahm and Kruger (2014).

Stress Calculation



Figure 1: Three orthogonal eigenvectors of moment tensor and orientation of fracture planes with respect to the P-axis and T-axis. Moment tensor solution results in two possible fracture planes: Plane 1 and Plane 2 (Left). The beach ball diagram represents a pure strike-slip event corresponding to the shown focal mechanism (Right).



Figure 2: Rake vector and rake angle (γ) on a fracture plane, looking from hanging wall. Rake angle is measured positive counter clockwise and negative clockwise from strike. mechanism (Right).

The stress calculation method includes two main steps, i) determination of horizontal stress direction, and ii) calculation of maximum horizontal stress magnitude.

1. Horizontal Stress Direction

Consistent with the common practice in the industry, the vertical stress is assumed as a principal stress, implying that the other two principal stresses are horizontal. Considering the high depth of unconventional reservoirs and as a result of the high magnitude of overburden pressure, this assumption holds true in most cases, unless a major structural feature, such as a fold or a fault, changes the state of stress locally.

Assuming the vertical stress is a principal stress, the direction of horizontal stresses can be determined from non-vertical fractures showing a pure dip-slip focal mechanism. The strike of such fractures is parallel to one of the horizontal stresses. This criterion is based on the fact that a compressive stress oriented parallel to a plane does not have any shear projection on that plane. Therefore, if a non-vertical fracture runs parallel to S_{Hmax} direction, the



Figure 3: Fracture planes with dip or strike parallel to one of the principal stresses. These fractures cannot be used for stress calculations because their rake vector (R) is no longer a function of relative stress magnitudes. The non-vertical fractures with their strike parallel to one of the horizontal stresses [(a) and (b)] show a pure dip-slip mechanism and can be used to determine the direction of horizontal stresses.

2. Maximum Horizontal Stress Magnitude

In this method, each focal mechanism is considered as an independent stress measurement experiment. A closed form solution is used to calculate the magnitude of maximum horizontal stress for each qualified focal mechanism. The field S_{Hmax} magnitude is then determined by interpreting all calculated magnitudes.

The state of stress in a formation is represented mathematically by a second-order stress tensor with six independent components, shown by a symmetric 3×3 matrix as follows:

$$\sigma_{ij} = \begin{bmatrix} \sigma_{11} & \sigma_{12} & \sigma_{13} \\ \sigma_{12} & \sigma_{22} & \sigma_{23} \\ \sigma_{13} & \sigma_{23} & \sigma_{33} \end{bmatrix}$$
(2)

For a given stress state, the components of stress tensor depend on the chosen reference coordinate system (tensor quantity). In the principal stresses coordinate system (i.e., the orthogonal coordinate system formed by eigenvectors of stress tensor) the off-diagonal components of the stress tensor are zero, and the stress tensor has the following form:

$$\sigma_{ij} = \begin{bmatrix} \sigma_1 & 0 & 0\\ 0 & \sigma_2 & 0\\ 0 & 0 & \sigma_3 \end{bmatrix}$$
(3)

where $\sigma_1, \sigma_2, \sigma_3$ are the three principal stress magnitudes corresponding to the three principal stress directions. Assuming the vertical stress (S_v) and maximum and minimum horizontal stresses (S_{Hmax} and S_{hmin}) are principal stresses, the stress tensor in unconventional reservoirs can be written as follows:

$$\sigma_{ij} = \begin{bmatrix} s_{Hmax} & 0 & 0\\ 0 & s_{hmin} & 0\\ 0 & 0 & s_{v} \end{bmatrix}$$
(4)

defined in the right-handed coordinate system formed by s_{Hmax}, s_{hmin}, and s_v directions, respectively.

Considering the variation of stresses in a layer with depth, the stress magnitudes in matrix 4 are usually reported by stress gradients with the unit of psi/ft or MPa/m. The stress gradient is considered to be constant through the depth interval corresponding to a layer. We normalize the stress tensor by s_v and rewrite it in the following form:

$$S_{ij} = \frac{\sigma_{ij}}{s_v} = \begin{bmatrix} k_H & 0 & 0\\ 0 & k_h & 0\\ 0 & 0 & 1 \end{bmatrix}$$
(5)

where $k_H = s_{Hmax}/s_v$ and $k_h = s_{hmin}/s_v$ are unitless normalized maximum and minimum horizontal stresses, respectively. Formatting the stress tensor in this way has two main advantages; i) it eliminates the vertical stress component (s_v) from the future equations, leaving k_H and k_h as the only variables, and ii) it addresses the vertical scatter of microseismic events within a given layer.

Knowing the orientation of fracture planes from the fault plane solution, the shear stress acting on each fracture plane is calculated as a function of $k_{\rm H}$ and $k_{\rm h}$. The governing equation for stress calculation is then formed by setting the external product of unit rake vector (R) and unit shear stress vector (T_s) to zero, as follows:

$$R \times T_s = 0 \tag{6}$$

By developing Equation 6 around k_{H} and k_{h} , a linear relationship is obtained that relates k_{H} to k_{h} for each fracture as follows:

$$k_{\rm H} = M_1 + M_2 k_{\rm h} \tag{7}$$

where M_1 and M_2 are two constants whose values are functions of the fracture plane orientation and rake, obtained from the fault plane solution. The details of deriving Equation 7 from Equation 6 can be found in Agharazi (2016).

The k_h in this equation represents the field k_h , which can be calculated if field s_{hmin} and s_v are known. By inserting the field k_h in Equation 7 a unique k_H is obtained for each focal mechanism. Hypothetically, in an ideal case where there are no stress disturbances and no noise in microseismic data, all calculated k_H values must be equal and represent field k_H . In practice, however, this is never the case, mainly because of the stimulation-induced stress changes and noisy microseismic data. The propagation and dilation of a hydraulic fracture results in the deformation of surrounding rock and changes in stresses within the treatment area.

Figure 4 shows the stresses around a conceptual propped-open vertical fracture determined by a numerical model (Agharazi et al. 2013). Based on this model, at least three stress zones can be identified around an ideal case of a planar bi-wing fracture; i) Stress-shadow zone (Zone 1) with increased stress magnitude perpendicular to the hydraulic fracture plane, ii) Shear zone at the leading edge of the hydraulic fracture (Zone 2) with modified stress direction and magnitude, and iii) Undisturbed stress zone (Zone 3) representing initial field stresses. In a real case, however, the stimulation pattern is more complicated due to interaction of the propagating fracture with pre-existing natural fractures, resulting in more variations in the stress field.



Figure 4: In-situ and induced stress zones around a propped-open vertical hydraulic fracture (map view crossing at the center of fracture). The shear zone (Zone 2) forms at the leading tip of hydraulic fractures. Both stress directions and magnitudes are altered in this zone. The stress-shadow zone (Zone 1) develops on the other side of the fracture and features higher compressive stress in the direction normal to the fracture plane (usually σ_{hmin} direction). In Zone 1, the stress directions remain mainly unchanged. Outside of these two zones, stresses are not changed and represent the initial field stresses (Zone 3).

The microseismic events acquired during a hydraulic fracturing treatment belong to both disturbed and undisturbed stress zones. However, the following parameters apply:

1. The stress changes in the treatment area occur due to deformation of rock under the net pressure applied during treatment (net pressure is equal to fluid pressure minus formation minimum stress). In most cases, the maximum applied net pressure is less than 10% of S_{hmin} and rapidly drops as the distance from the injection point (perforations) increases, due to high frictional pressure losses. Hence, it can be assumed that the magnitude of stress changes is not significant compared to the magnitude of field stresses, and it merely affects a relatively small area at the vicinity of the injection point, suggesting that most microseismic events represent the undisturbed stress state.

2. Comparison of microseismic event timing with pumping time indicates that a relatively higher number of events occur after pumping for a while, suggesting that most acquired events are pressure-induced (wet events) rather than stress-induced (usually dry events). In other words, most microseismic events are associated with an increase in fluid pressure rather than changes in field stresses. Therefore, it can be argued that most microseismic events represent rock failure under an undisturbed state of stress.

The calculated k_H for all events can be plotted on a histogram, as shown in Figure 5 for a Marcellus well. In this case, most k_H values fall in the $k_H < 1$ range, which is consistent with our knowledge of the normal faulting field stress regime in that region. As a result, all k_H values greater than 1 must be excluded. The estimation of field k_H from the remaining events is a matter of engineering judgment and interpretation. By default, we use the least-squares method to establish an instance of Equation 7 that best fits the known field k_h and the valid k_H values. In this methodology, the model parameter that we are searching for is just M_2 , knowing that $M_1 + M_2 = 1$ in Equation 7.



Figure 5: Distribution of calculated k_H for a Marcellus well.

3. Considerations

There are two important factors that affect the accuracy of the stress calculations described above and need to be addressed properly:

- Noisy microseismic data
- Inherent ambiguity in fault plane solution

As mentioned earlier, the inversion technique is used to find a moment tensor that best matches the observed radiation patterns of seismic amplitude at different locations for each event. Due to the noise in the acquired microseismic data, the obtained moment tensor is not an exact solution but is a best-fit solution with an inherent level of uncertainty. A major factor affecting the accuracy of the solution is the strength of seismic signal relative to the noise level, which is quantified and represented by the signal-to-noise ratio (SNR). The higher the SNR, the higher the event quality, and the lower the uncertainty in the moment tensor solution.

The uncertainty in the moment tensor inversion is taken into account mathematically when calculating the fault plane solution. It is represented in the form of a standard error for the calculated fracture orientation and slip direction for each event. From a stress calculation perspective, the uncertainty in the moment tensor solution potentially poses two main problems:

- For near-vertical fractures, slight deviations of the estimated dip of the fracture on either side of vertical can
 produce an artificially reversed rake vector for some events, meaning that the calculated slip direction is 180°
 off from the real slip direction (polarity in rake vector).
- For fractures with a near pure dip-slip focal mechanism (fractures with rake angle close to ±90°), slight deviations of the estimated rake angle on either side of ±90° can artificially reverse the horizontal projection of slip for some events.

The inherent ambiguity in the fault plane solution refers to the fact that the solution provides two possible fracture planes for each seismic event, a real plane and an auxiliary plane that are orthogonal to one another (Figure 1). The auxiliary plane has no physical value and is merely the byproduct of the solution. The moment tensor itself does not provide any further information that can be used to distinguish the real plane.

From a stress calculation perspective, fractures with either of the above issues (i.e., flipped dip or rake and auxiliary plane) are not compatible with the true field stress directions. They artificially follow an incorrect stress configuration whose axes are rotated by 90° around one or two of the true stress directions. These "incompatible" events generate a significant error in the calculated stress magnitude and must be identified and addressed properly before proceeding to stress calculation. We address these issues by:

- 1. Using a minimum SNR threshold to filter out low quality events
- 2. Running a pre-processing step to identify and tag incompatible events

The pre-processing step includes i) finding the direction of horizontal stresses and establishing the reference coordinate system of principal stresses, and ii) forming Equation 7 in the reference coordinate system for each event. An important characteristics of the M_1 and M_2 coefficients in Equation 7 is that they follow a sign convention consistent with the stress regime that governs the slip on the fracture plane, as shown in Table 1.

Stress Regime	$\sigma_3 < \sigma_2 < \sigma_1$	Normalized stresses	M_1	M_2
Normal Faulting	$S_{hmin} < S_{Hmax} < S_v$	$k_h < k_H < 1$	+	+
Strike Slip	$S_{hmin} < S_v < S_{Hmax}$	$k_h < 1 < k_H$	+	-
Reverse Faulting	$S_v < S_{hmin} < S_{Hmax}$	$1 < k_h < k_H$	-	+

Table 1: Signs of M_1 and M_2 for three possible stress regimes

Table 1 can be consulted to examine each event and tag those that are not compatible with the known field stress directions. For example, if the measured S_{hmin} in a formation is smaller than S_v (i.e., $k_h < 1$), the field stress regime is either normal faulting or strike-slip. Therefore, any fracture with $M_1 < 1$ is considered incompatible with field stresses and will be tagged accordingly. It also should be noted that the potential polarity issue in rake vector (artificially reversed rake vector) has no influence on the calculated stress magnitudes. This is because the chosen governing equation remains valid as long as rake and shear stress vectors are parallel, irrespective of their directions. These are two important advantages of this methodology for stress calculation based on microseismic focal mechanisms.

Our investigation of several cases in different formations indicates that even after filtering out the low quality events by using a minimum SNR threshold, the data set still contains a considerable percentage of incompatible events. This highlights an important problem in applying the stress inversion technique to estimate field stresses from microseismic focal mechanisms. A main assumption in the inversion technique, in general, is that the field observations (here rake vectors) all belong to the same population and can be predicted by a single model, provided that the model parameters are known. Therefore, the inversion technique is used to find the model parameters that best fit the field observations. However, as previously discussed, the focal mechanisms determined for a hydraulic fracturing stimulation do not all follow the same stress regime (or model), mainly due to the treatment-induced stress disturbances and noisy microseismic data. Applying the inversion technique to such data sets results in a nonrepresentative stress estimate, if a stable solution can ever be reached.



Figure 6: Fracture poles as determined by moment tensor solution for studied cases. Poles are shown on a lower hemisphere stereonet. The number of input data points is shown on each plot.

Case Studies

In this section, we provide five case studies in three different formations; the Marcellus, Eagle Ford, and Wolfcamp. In all cases, the S_{Hmax} magnitude is calculated for the target layer (pay zone), using the microseismic events belonging to that layer. All microseismic data were acquired using surface arrays. Figure 6 shows the orientation of the fractures determined from the moment tensor solution for each studied case. These data, along with the rake vector for each event, form the basis for stress calculation.

• Marcellus

We studied three cases in the Marcellus, Case A, Case B, and Case C, at different locations. All cases were treated using slickwater and a plug-and-perf completion technique. For all cases, the vertical stress gradient was calculated from density logs. The S_{hmin} gradient was either reported by the operator or was taken from the available reports and literature.

Case A includes three horizontal wells with an average lateral length of 6,000–7,000 ft. The average stage length was 170 ft. Each well was completed independently after the completion of the previous well. In total, 2,409 microseismic events were recorded in the Marcellus layer. A minimum signal-to-noise ratio of SNR≥8 was considered for the calculations. The S_{Hmax} direction was determined as N052° from 75 focal mechanisms. The S_{Hmax} magnitude was determined based on 1,832 qualified events. The results are shown in Figure 7.

Case B represents the first five stages of one horizontal well. In total, 286 microseismic events were recorded. The minimum SNR threshold was set to SNR=10 for the stress analysis. The maximum horizontal stress direction was estimated at N057°, based on 22 focal mechanisms. The results of stress analysis are shown in Figure 7.

Case C includes two horizontal wells completed using a zipper-frac technique, with average lateral length of approximately 7,000 ft and average spacing (between two wells) of 1,800 ft. In total, 1,002 microseismic events were recorded in the Marcellus layer, of which 624 events were used for stress calculation. The minimum SNR threshold was set to SNR=6. The direction of maximum horizontal stress was determined as N062° from 33 focal mechanisms. The stress analysis results are shown in Figure 7.

• Eagle Ford

The studied case in the Eagle Ford formation includes four horizontal wells completed using a zipper-frac technique, with an average lateral length of 8,000 ft and average well spacing of 250 ft. All wells were completed using slickwater and plug-and-perf method. In total, 1,292 microseismic events were acquired in the lower and upper Eagle Ford layers. A signal-to-noise ratio threshold of SNR=9 was considered. The S_{Hmax} direction was estimated at N046°, based on 65 focal mechanisms. The vertical stress gradient was calculated from the density log of a nearby pilot well. Due to lack of project-specific data, the S_{hmin} was estimated based on the reported values for other projects close the study region. Figure 7 shows the results of stress calculation.

• Wolfcamp

This case includes two horizontal wells completed using a zipper-frac technique, with a treated length of approximately 1,400 ft. In total, 426 events were acquired in the Wolfcamp layers. The SNR threshold was set to SNR=5. The S_{Hmax} direction was determined at N103°, based on three focal mechanisms and the general trend of microseismic events. The stress calculation results are shown in Figure 7.



Figure 7: Stress calculation results for the studied cases. For each case, the determined orientation of horizontal stresses is shown on the left. The determined field stress regime and the linear relationship between normalized maximum and minimum horizontal stresses (k_H and k_h) are shown in the middle column, along with the stress magnitudes. In all cases, the vertical and S_{hmin} magnitudes come from other sources, and the S_{Hmax} magnitude was then calculated for the formation using the established relationship between k_H and k_h . The Mohr plots on the right show field stresses and the initial state of stress on fracture planes.

Pressure Analysis – Failure Pressure

In naturally fractured reservoirs, the efficiency of hydraulic fracturing treatment depends largely on the activation of natural fractures. This helps to enhance effective complexity in the reservoir and to improve the interconnected fluid network. The natural fractures slip by two means, i) interaction with the induced hydraulic fracture as it grows and crosses natural fractures, and ii) by the increase of fluid pressure.

The minimum fluid pressure required to initiate failure on natural fractures can be calculated if the field stress tensor, fracture orientations, and shear strength characteristics of the fracture planes are known. For fracture planes derived from a fault plane solution of microseismic events, this analysis can provide insight into the minimum induced pressure during the treatment. Considering that neither natural fracture orientations nor stress tensor changes dramatically from one well to another within the same pad or region, the results of such analysis can help to optimize the treatment parameters, such as fluid viscosity and pump time, for the next wells to be completed.

For calculation of the failure pressure, we use the Mohr-Coulomb shear failure criterion. Based on this criterion, a fracture undergoes shear failure if the shear stress acting on the fracture plane (τ) reaches or exceeds the shear strength available on the fracture, which is mathematically represented by the following equation:

$$\tau = c + (\tan \varphi) \,\sigma'_n \tag{8}$$

where c and ϕ are the cohesion and friction angle of fracture surface (constant and characteristics of rock), and σ'_n is the effective normal stress acting on the fracture plane, which is equal to:

$$\sigma'_{n} = \sigma_{n} - p \tag{9}$$

where σ_n is the total normal stress and p is the fluid pressure. By substituting Equation 9 into Equation 8, the pressure at failure (p_f) is determine as follows:

$$p_{f} = \sigma_{n} + \frac{c - \tau}{\tan \varphi} \tag{10}$$

 σ_n and τ are calculated from the stress tensor for each fracture. An underlying assumption in this method is that upon the increase of fluid pressure, the fracture undergoes shear failure before the increased pressure reaches normal stress and opens the fracture. Theoretically, this holds true in all cases except for when the fracture plane is oriented perpendicular to one of the principal stresses. The stress disturbances caused by stimulation are also ignored in this method. Figure 8 shows the failure potential (initial ratio of τ/σ_n) and failure pressure contours for one of the studied cases in the Marcellus (Case C).



Figure 8: Initial failure potential (τ/σ_n) (left), and failure Pressure Contours (right) for Marcellus-Case C. The Mohr-Coulomb criterion parameters are c=0, $\varphi = 23^{\circ}$

Conclusion

A new methodology was described for the estimation of field S_{Hmax} direction and magnitude from microseismic focal mechanisms. The described method was used to calculate field S_{Hmax} for five cases in three different formations. An example pressure analysis, based on the calculated field stresses and the microseismically determined fracture orientations was presented for one of the studied cases in the Marcellus.

References

Agharazi A., 2016. Determination of Maximum Horizontal Field Stress from Microseismic Focal Mechanisms – A Deterministic Approach. Paper ARMA 16-691 presented at 50th US Rock Mechanics /Geomechanics Symposium, Houston, TX, USA, 26-29 June.

Agharazi, A., B. Lee, N.B. Nagel, F. Zhang, M. Sanchez, 2013. Tip-Effect Microseismicity – Numerically Evaluating the Geomechanical Causes for Focal Mechanisms and Microseismicity Magnitude at the Tip of a Propagating Hydraulic Fracture. In Proceedings of the SPE Unconventional Resources Conference Canada, Calgary, 5-7 November 2013

Amadei B., O. Stephansson, 1997. Rock Stress and Its Measurement. London: Chapman & Hall

Dahm, T., F. Kruger, 2014, Moment tensor inversion and moment tensor interpretation. In New Manual of Seismological Observatory Practice 2 (NMSOP-2), ed. Bormann P. 1-37

Jost, M.L., R.B. Herrmann. 1989. A Student's Guide to and Review of Moment Tensors. Seismological Research Letters, 60(2), 37-57

Nagel, N.B., M. Sanchez-Nagel, F. Zhang, X. Garcia, B. Lee, 2013. Coupled Numerical Evaluations of the Geomechanical Interactions Between a Hydraulic Fracture Stimulation and a Natural Fracture System in Shale Formation. Rock Mech Rock Eng 46:581-609.

Neuhaus, C.W., S. Williams, C. Remington, B.B. William, K. Blair, G. Neshyba, T. McCay. 2012. Integrated Microseismic Monitoring for Field Optimization in the Marcellus Shale – A Case Study. In Proceedings of the SPE Canadian Unconventional Resources Conference, Calgary, 30 October – 1 November 2012

Sasaki, S., H. Kaieda, 2002. Determination of Stress State from Focal Mechanisms of Microseismic Events Induced During Hydraulic Injection at the Hijiori Hot Dry Rock Site, Pure appl. geophys. 159, 489-516

Sinha, B.K., J. Wang, S. Kisra, J.Li, V. Pistre, T. Bratton, M. Sanders, C. Jun. 2008. In Proceedings of 49th Annual Logging Symposium, Austin, 25-28 May 2008

Zhang, F., N.B. Nagel, M. Sanchez-Nagel, BT Lee, A. Agharazi, 2013. The Critical Role of In-Situ Pressure on Natural Fracture Shear and Hydraulic Fracturing-Induced Microseismicity Generation"., SPE paper 167130 presented at the SPE Unconventional Resources Conference-Canada, Calgary, Alberta, 5-7 November.

Zoback M.D., 2010. Reservoir Geomechanics. 1st ed. New York: Cambridge University Press.