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Petrophysical and Geomechanical Characterization of the Marcellus Shale in the Appalachian Basin

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Petrophysical and Geomechanical Characterization of the Marcellus Shale in the Appalachian Basin

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Dissertation submitted to the
Eberly College of Arts and Sciences
at West Virginia University
in partial fulfillment of the requirements
for the degree of

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in
Geology

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Geomechanics, Hydraulic fracturing

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ABSTRACT

Petrophysical and Geomechanical Characterization of the Marcellus Shale in the Appalachian Basin

Yixuan Zhu

In recent years, more and more attention is paid to shale gas and hydrocarbon liquids exploration and exploitation in unconventional reservoirs. With the development of horizontal drilling and hydraulic fracturing, production from unconventional reservoirs has been greatly increased. However, not all wells, regions and basins harbor highly successful shale gas and liquids producers. In order to improve the production efficiency and reduce the cost of projects, detailed analysis needs to be undertaken to characterize the reservoir. As opposed to conventional reservoirs, extraction of gas in the unconventional reservoir is dependent not only on the reservoir quality, but also on completion quality. The dissertation focuses on three studies that affect reservoir and completion quality of unconventional reservoir units in the Marcellus Shale of the Appalachian basin.

1) Combined with petrophysical analysis from lab and well logging data, nitrogen adsorption is adopted to explore pore characterization of the organic-rich Marcellus Shale and the overlying organic-lean Mahantango Formation. We found that the isotherms of shale can be seen as composite isotherms, which have features of Type I, Type II and Type IV isotherms. The isotherm in the organic-rich Marcellus Shale is more similar to Type H4 of hysteresis loop, suggesting slit-like pores developed in the Marcellus Shale. Fractal analysis shows that the Marcellus Shale with a significantly higher total organic carbon (TOC) content has a more complex pore structure than the Mahantango Formation. Quantitative analysis shows that TOC content has positive relationships with specific surface area, and micropore volume. It indicates that shale samples with high TOC content can store more gas. Therefore, TOC content is a critical parameter to predict gas storage capacity.

2) Hydraulic fracturing is critical to economic production of shale oil and gas from unconventional reservoirs. Success of completion is closely related to gas production. In this study, we found that three factors appear to control hydraulic fracture stimulation. One is the presence of pre-existing natural fractures. Natural fractures were developed in similar patterns with high dip angle in the Marcellus and overlying Mahantango shale units, and are favorable for vertical fracture propagation. The second factor is reservoir geomechanical characterization. The Marcellus Shale has obvious presence of overpressure. According to the study on stress state using a Mohr's circle, overpressure in the Marcellus Shale increases the possibility of frictional sliding of pre-existing fractures especially at lower value of least principal stress, and will keep some fractures at certain dip angles open. The unconfined compressive strength (UCS) computed from empirical equations for the Marcellus Shale has significantly lower rock strength. The third factor is fracture barrier. The Onondaga Limestone below the Marcellus Shale serves as a critical fracture barrier in our study area. We found that Onondaga fracture barrier with relative high effective minimum horizontal stress and adequate thickness is more

effective to prevent the microseismic growing down to other formations.

3) Microseismic monitoring is a useful tool to detect the hydraulic fractures. By observing the microseismic events recorded during the hydraulic fracturing, we found that some basic microseismic characterization such as event number, dominant microseismic azimuth vary stage by stage. To interpret the variations of this characterization, we found that combination of b-value and D-value can be used to interpret the activation of faults and natural fractures. By employing time-distance plot, presence of faults or natural fractures results in higher hydraulic diffusivity. Natural fractures and stress shadow can be used to explain the variation of dominant microseismic azimuth for the stages near the heel of the horizontal well. By applying stress shadow into an unconventional fracture model (UFM), simulated hydraulic fractures are in agreement with distribution of most microseismic events. The hydraulic fractures in the stress shadow grow towards area of next stage, which may be helpful for the production of next stage. However, for the current stage, as fracturing is not sufficient to create more fractures in corresponding area, it may result in the low production in this stage.

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1. Introduction

The Marcellus Shale was deposited during the middle Devonian in the Appalachian basin (Figure 1.1). The Middle Devonian Acadian orogeny was a result of the collision between the Laurasia continent and a series of Avalonian continental fragments. The uplift of orogeny and rapid subsidence lead to deposition of organic-rich black shale, followed by deposits of organic-lean gray shale and siltstone. The Appalachian basin consists of the Appalachian Plateau, and Valley and Ridge provinces. From west to east, structural complexity increases from the Appalachian Plateau province, which is marked by a lack of intense faulting in west to high amplitude, detached, salt-cored anticlines and synclines (Zagorski et al., 2012).

Figure 1.1. Middle Devonian paleogeography (after Blakey, 2005).

In the stratigraphic chart (Figure 1.2), the Marcellus Shale belongs to the Hamilton Group overlying the Onondaga Limestone and underlying the Tully Limestone. Above the Marcellus Shale is the Mahantango Formation characterized by organic-lean shale. In lithology, the Marcellus Shale is composed of organic-rich carbonaceous silty dark gray to black shale. Heavy minerals, carbonate concretions and fossils are scattered in the shale. As black shale is interbedded with carbonate-rich zones, the Marcellus Shale can be informally separated into the upper, middle and lower Marcellus.

Figure 1.2. Stratigraphic chart for the central Appalachian basin (modified from USGS, 2011).

The study area is located in the middle part of the Appalachian basin across Pennsylvania and West Virginia (Figure 1.3). The Marcellus Shale is buried to a great depth (5750ft to 6000ft subsea) in the north and relatively shallower to the south, southwest and east of this region. The data used in the study are located in the Greene County, Monongalia County, Harrison County and Webster County from north to south. The wells shown on Figure 1.3 represent the Marcellus Shale wells with a range of production success that may be influenced by reservoir and completion quality. The shale gas production was successful in the regions of the Greene County, Monongalia County and Harrison County, while wells in the Webster County failed to produce. In these areas especially for the four wells shown in the map, comprehensive data are available to undertake the research, including cores, well logging and microseismic data. In order to explore the key influence of successful production, petrophysical and geomechanical properties of the Marcellus Shale will be characterized in these areas, and comparisons will be carried out. The organization of the dissertation is in three sections structured as independent but related papers intended to be submitted for publication.

Figure 1.3. Structural map of subsea depth (ft) of the Marcellus Shale. Data used in the study are from four regions from north to south: Greene County, Monongalia County, Harrison County and Webster County. Wells shown on the map have comprehensive well logging data.

2. Study of Pore Characterization by Nitrogen Adsorption and Its Implication of Gas Storage Capacity for the Marcellus Shale

Abstract

In a shale gas reservoir, pore characterization is an important factor to determine gas storage capacity. However, the nanometer (nm) scale pore system in shale is difficult to explore by traditional optical, scanning electron microscopy (SEM) or even nuclear magnetic resonance (NMR) well logging. Combined with petrophysical analysis from lab and well logging data, nitrogen adsorption is adopted to explore pore characterization of the organic-rich Marcellus Shale and overlying organic-lean Mahantango Formation. The nitrogen adsorption experiment on shale samples provides detailed information on pore system. The isotherm of shale can be seen as composite isotherm, which has features of Type I, Type II and Type IV isotherms. The isotherm in the organic-rich Marcellus Shale is more similar to Type H4 of hysteresis loop, it suggests slit-like pores developed in the Marcellus Shale. Fractal analysis based on Frenkel-Halsey-Hill (FHH) model shows that the Marcellus Shale has more complex pore structure than the Mahantango Formation, which is the result of high total organic carbon (TOC) content. In addition, shale samples with high TOC have large specific surface area. It suggests that more gas is adsorbed in the shale with high TOC. Micropores in the shale have negative relationship with clay mineral and positive relationship with TOC content and kerogen. By employing Langmuir and Brunauer-Emmet-Teller (BET) model, simulated result indicates that higher adsorbed quantity could be explained as a result of increase of micropore volume which is contributed by increase of kerogen or TOC content. TOC content has positive relationship with specific surface area and micropores, thus it is an important parameter to predict gas storage capacity.

2.1 Introduction

In all reservoirs, pore characterization to determine effective porosity and hydrocarbon saturation is critical to determine reservoir hydrocarbons in-place volumes. For a shale gas reservoir, evaluation of reservoir gas in-place volume is a challenge, because most of gas is adsorbed on the pore surfaces except of free gas or saturated fluid in the pore. The majority of pores are nano-scale pores and can be less than 10nm (Song et al., 2019). In recent years, scanning electron microscopy (SEM) is generally used to observe pores in shale (Wang et al., 2009; Sondergeld et al., 2010; Curtis et al., 2012). However, it still has limitations. First, many of pores are below the resolution of typical SEM's or require such significant magnification that is difficult to obtain a sample size representative of a heterogeneous shale reservoir, and preparation of sufficient samples is time consuming and expensive. Second, SEM provides two-dimensional image for pore system, thus it is hard to provide three-dimensional information such as pore surface area and volume. Well logging is also a useful tool to provide the information on reservoir volume. However, we found that logs even nuclear magnetic resonance (NMR) logs can significantly under represent the porosity based on observation of

the well in the study area. In our study, well MIP3H, porosity measured by NMR logging is shown in track 2 (Figure 2.1). Three types of porosity are able to be measured by NMR (Figure 2.2). In the Marcellus Shale, free-fluid porosity (CMFF) is very low, while effective porosity (CMRP_3MS) and total porosity (TCMR) are relatively high. It suggests that the Marcellus Shale has a high amount of capillary-bound water and clay-bound water. Compared the Marcellus Shale with the organic leaned Mahantango Formation, there is no significant change on total porosity. One possible reason is incomplete gas polarization because hydrogen density of gas is lower than fluid (Allen et al., 1997). Therefore, NMR porosity may underestimate porosity in gas zone in shale. In other words, NMR porosity may not reflect porosity in kerogen that is filled by gas. Data used for this study are mainly from the pilot well of MIP3H in Monongalia County, West Virginia, USA. We examine petrophysical characterization including lithology, total organic carbon (TOC) content. Then, an experiment of nitrogen adsorption is conducted for shale samples. Integrated analysis are carried out between petrophysical characterization and pore structure analysis from nitrogen adsorption to explore the storage capacity of shale reservoir.

Figure 2.1. NMR porosity in MIP3H, West Virginia, USA. Track 1 contains gamma-ray (GR) in API units, and track 2 is computed free-fluid porosity (CMFF), effective porosity (CMRP_3MS) and total porosity (TCMR) from nuclear magnetic resonance (NMR) logging.

Figure 2.2. Schematic of NMR fluid model (after Allen et al., 1997).

2.2 Petrophysical Characterization

2.2.1 Lithology

Well logs provide continuous measurements of mineralogy and lithology. In the range of the Marcellus Shale, five mineral components in weight percentage from well logs are compared with independent XRD-XRF experiment results (Hupp et al., 2018) (Figure 2.3). Components from well logs fall into the range and reflect the variations of measured results from XRD-XRF, and provide real and continuous information in the subsurface. A probabilistic lithologic model (Schlumberger elemental log analysis - ELAN) is used to compute the volumetric percentage of selected lithology (Figure 2.4). In the upper Marcellus, quartz and clay minerals are dominant components, but the volume of kerogen is relatively low. In the middle Marcellus, there is no obvious change in mineral components, and quartz and clay minerals still comprise a large volume of all components, but average volume of kerogen is increasing with depth. In the lower Marcellus, volumetric percentage of quartz is relative stable and no significant change compared with the upper and middle Marcellus, but clay minerals and carbonate have a considerable variation. The kerogen has a high amount around the depth of 7544ft. Compared to the Marcellus Shale, the Mahantango Formation has a relative high amount of clay minerals, and relative low amount of kerogen. Six shale samples were selected from different depth (Figure 2.4). Two of them are from the Mahantango Formation and named as Mahantango 1, Mahantango 2. Four samples are from the Marcellus Shale and named as upper Marcellus, middle Marcellus, lower Marcellus 1 and lower Marcellus 2 based on the relative depth in the Marcellus Shale.

Figure 2.3. Comparison for mineral composition in weight percentage between well logging results and experiment results from XRD-XRF. QFM represent quartz, feldspar, and mica.

Figure 2.4. Composition of eight lithologic components in volumetric percentage computed from ELAN model. Green dots on the left column represents the depth of six shale samples that are used in nitrogen adsorption analysis.

2.2.2 Total Organic Carbon (TOC)

The total organic carbon (TOC) content is a parameter to characterize the organic richness. TOC can be measured in the lab, but not all wells have cores, which can be used for this measurement. Data from well logs are usually used to predict the TOC. There are two widely used methods. One is Schmoker method (Schmoker, 1979; Schmoker, 1980). This method is based on empirical relationship between bulk density and TOC to predict the TOC. The other method known as $\Delta\log R$ method combines resistivity and density to predict TOC (Passey et al., 1990). We computed the TOC using these two methods (detailed methods shown in appendix 1). The results from these two methods are similar, but they do not match the independent lab measured TOC very well, especially in the lower Marcellus (Figure 2.5). In the lower Marcellus, the lab measured TOC is significantly higher than the log measured TOC, probably due to the over-matured Marcellus Shale at the MIP3H well. In order to improve the accuracy of prediction of TOC especially for lower Marcellus with relative high gamma ray, we modified $\Delta\log R$ method, and use combination of resistivity and gamma ray to predict TOC. The equations are shown below:

$$\Delta\log R_GR = \log_{10}(R / R_{baseline}) + a \times (GR - GR_{baseline}) \quad (2.1)$$

$$w_{TOC} = (\Delta\log R_GR) \times 10^{(2.297 - 0.1688 \times LOM)} \quad (2.2)$$

where R is the deep resistivity from log; GR is the gamma ray from log; a is the scaling factor; LOM is the level of organic maturity and 10.5 is used for over-matured Marcellus Shale ((Hood et al., 1975; Passey et al., 2010; Charsky et al., 2013).

The correlation coefficient between computed and lab measured TOC are 0.60, 0.64, and 0.87 respectively for Schmoker method, $\Delta\log R$ method, and proposed method. The calculated result using proposed method matches the lab measured TOC better than the other two methods, especially for the lower Marcellus. Based on the lab and computed results, the lower part of middle and lower Marcellus has relative higher TOC. TOC steadily increases with depth, and highest value are around the depth of 7544ft.

Figure 2.5. TOC computed using Schmoker method (Schmoker, 1979; Schmoker, 1980), $\Delta\log R$ method (Passey et al., 1990) and proposed method. The red crosses are TOC measured independently in the lab.

2.3 Quantitative Analysis for Adsorption Isotherm

In recent years, nitrogen adsorption is widely used in exploring pore surface area, micropore volume and pore structure in shale (Ross and Bustin, 2009; Chalmers et al., 2012; Clarkson et al., 2012; Liu et al., 2015; Sun et al., 2016). Quantitative analysis of the isotherm is crucial to explore storage capacity of shale. In the experiment, solid such as shale is named as the adsorbent, while adsorbable gas is the adsorptive. Nitrogen adsorption conducted for shale belongs to physisorption. The physisorption phenomenon occurs when the adsorptive is brought into contact with the surface of adsorbent (Sing et al., 1985). In our study, nitrogen adsorption analysis was conducted on six shale samples from the Mahantango Formation and Marcellus Shale using Micromeritics ASAP-2020 instrument at liquid nitrogen temperature (77K). TOC content of these six samples was measured in the lab (Table 2.1). TOC content of these six samples increases generally with depth. Although TOC of lower Marcellus 2 is slightly lower than lower Marcellus 1, it still has a relative high value compared with other samples.

Table 2.1. Six shale samples from different depth with lab measured TOC.

Depth (ft)	Samples	TOC (wt%)
7440	Mahantango 1	3.01
7451	Mahantango 2	3.14
7465	upper Marcellus	4.14
7506	middle Marcellus	6.64
7541	lower Marcellus 1	8.86
7543	lower Marcellus 2	7.50

2.3.1 Nitrogen Adsorption Isotherm

According to the relationship between relative pressure and adsorbed volume, adsorption isotherms are classified into four types and associated with four hysteresis types shown in Figure 2.6 (Sing et al., 1985). These types of isotherms are classified based on a large amount of physical adsorption isotherms measured in practice, and they have close relation with presence of micropores, mesopores, and macropores. Following classification for physisorption, pores with widths ranging between 2nm to 50nm are defined as mesopores; pores with widths less than 2nm are micropores, and pores with widths greater than 50nm are macropores (Sing et al., 1985).

(a)

(b)

Figure 2.6. Types of adsorption isotherms (a) and hysteresis loops (b) (Sing et al., 1985).

Most common types of isotherms are Type I, Type II and Type IV isotherm (Figure 2.6a). Type III isotherm is concave in the whole range. This type of isotherm is valueless in pore or surface analysis because it is formed in the condition where the adsorptive has greater affinity for each other than they do for adsorbent (Webb et al., 1997). Type I isotherm is a character of microporous adsorbent. It is characterized by convex shape at relative low pressure and horizontal plateau as relative pressure approaching to 1. The convex at the beginning suggests enhanced adsorptive process by micropores. As relative pressure increase, the solid cannot take up more gas so that isotherm presents saturated condition as a horizontal plateau. Type II isotherm is character of non-porous or macroporous adsorbent. It is composed by a pair of convex and concave curve linked by relative linear section in middle. The convex suggests completion of monolayer and start of multilayer adsorption, while the concave is a sign of enhanced increase of adsorbed quantity at high relative pressure and suggests macropore adsorption. Type IV isotherm is mainly related to mesopores. It is characterized by hysteresis loop, which is a product of adsorption and desorption curves, and by limited uptake at a range of high relative pressure. In the process of adsorption, it follows Type II isotherm at the beginning. When the relative pressure is around 0.4, isotherm is deviated upward sharply, which is a result of capillary condensation in mesopores. Finally, a slope decrease at relative high pressure implies completion of adsorption in mesopores.

Four types of hysteresis loops indicate different characteristics of pores (Figure 2.6b). Phenomenon of hysteresis loop is usually relative to capillary condensation in mesopores. For generation of hysteresis loop, there are different kinds of explanations, but most of them rely on capillary condensation and the Kelvin equation. It expresses as one adsorbed quantity corresponds to two relative pressures, or branches with desorption higher than adsorption. Pore character and shape can be speculated from the variety of hysteresis loops. Type H1 has two parallel and almost vertical branches. It implies the uniform pores that result in concentrated capillary condensation and discharge. Type H2 has a wider loop. Compared to normal adsorptive process, branch of desorption is almost no changes at the beginning and then drops dramatically from high to low relative pressure. It indicates that adsorbate will be discharged at same time when pressure is lowered to certain value. It suggests pores in this type are associated with narrow neck and large body. Type H3 and H4 shows no limiting adsorption, which implies capillary condensation occurs at high relative pressure. It may be explained by slit-like pores formed by plate-like particles, because it is difficult to form curved interface by parallel plates than cylindrical cube. Different with Type H3, Type H4 has character of Type I isotherm, which may be related to presence of micropores.

In our shale samples, adsorption isotherms (Figure 2.7) cannot be categorized into any single isotherm type because of heterogeneity of shale. All isotherms of shale samples have hysteresis loop, which is character of Type IV isotherm and indication of mesopores. However, different than Type IV isotherm, isotherms keep increasing when relative pressure approaching 1, which is character of Type II isotherm. Isotherms of lower Marcellus 1 and lower Marcellus 2 have narrow hysteresis loop, and two branches are almost parallel with each other. They are more similar to Type I isotherm, which is a character of micropores and may be related to the abundant kerogen in these two samples. For hysteresis loop, all isotherms are more similar to Type H4, which suggests slit-like pores. Therefore, isotherms of the shale should be seen as composite isotherm and dominated by slit-like pores.

Figure 2.7. Nitrogen adsorption isotherms for six shale samples.

2.3.2 Fractal Analysis

Fractal analysis can be used to study the geometry or structure of irregular porous material (Pfeifer and Avnir, 1983). This analysis is based on Frenkel-Halsey-Hill (FHH) model, and it has been used to study shale (Liu et al., 2015; Sun et al., 2016; Yang et al., 2016). The D value varies from 2 to 3, and the higher D value indicates a more complicated or rougher pore surface. The model is shown as below:

$$\ln(v) = b \ln(\ln(p_0 / p)) + c \quad (2.3)$$

$$b = D - 3 \quad (2.4)$$

where v is the adsorbed volume at equilibrium pressure p ; p_0 is the saturated pressure; c is the constant; D is the fractal dimension.

Fractal analysis results for the six shale samples are shown (Figure 2.8). In a departure from results in previous studies, there is no clear point to separate the linear line into two segments for our samples shale (Liu et al., 2015; Sun et al., 2016; Yang et al., 2016). Therefore, all data are used to fit the model. The fitting and calculated results are listed in Table 2.2. For samples from the Mahantango Formation, D values from sample Mahantango 1 and Mahantango 2 are similar to each other. For the Marcellus Shale, the D value ranges from 2.7824 to 2.9215. It suggests that the organic-rich Marcellus Shale has more complicated pore structure or rougher surface than the organic-lean Mahantango Formation.

Figure 2.8. Fractal analysis for adsorption branch of nitrogen adsorption isotherms for all samples.

Table 2.2. Fractal analysis for six shale samples.

Sample	slope	R^2	D
Mahantango 1	-0.2737	0.9854	2.7263
Mahantango 2	-0.2667	0.9896	2.7333
upper Marcellus	-0.2176	0.9747	2.7824
middle Marcellus	-0.1575	0.9281	2.8425
lower Marcellus 1	-0.0785	0.8606	2.9215
lower Marcellus 2	-0.1169	0.9307	2.8831

In order to explore relationships between fractal dimension and rock components, comparisons have been carried out for all samples. Based on the study, there is no clear relationship between fractal dimension and different mineral components. However, fractal dimension has a positive relationship with TOC and kerogen (Figure 2.9). It suggests that shale with high TOC content or large volume of kerogen has an increasingly complex pore structure.

(a)

(b)

Figure 2.9. Relationship between fractal dimension and (a) kerogen and (b) TOC.

2.3.3 Specific Surface Area and Micropore Volume

Quantitative analysis for adsorption isotherm relies on different models according to characteristic of isotherms. A type I isotherm is assumed to conform to the Langmuir model (Langmuir, 1916), which is based on assumption of only one molecular layer formed on solid.

Langmuir equations are expressed in two forms:

$$v = \frac{v_m cp}{p_0 + cp} \quad (2.5)$$

or in linear form

$$\frac{p/p_0}{v} = \frac{1}{v_m c} + \frac{1}{v_m} (p/p_0) \quad (2.6)$$

where v is the quantity adsorbed (cm^3/g in STP); p is the equilibrium pressure (pa); v_m is the monolayer volume (cm^3/g in STP); p_0 is the saturation pressure (pa); c is a constant related to interaction energy between adsorbent and adsorbate.

Dependent on basis of Langmuir model, the BET model is built for a Type II isotherm. The BET isotherm is constructed by introducing simplified assumptions into Langmuir isotherm (Brunauer et al., 1938). The assumptions address complications of heat of adsorption, evaporation-condensation conditions and condensation at saturation pressure. The equations are expressed as below:

$$v = \frac{v_m cp}{(p_0 - p)[1 + (c - 1) p/p_0]} \quad (2.7)$$

or in linear form

$$\frac{p/p_0}{v(1 - p/p_0)} = \frac{1}{v_m c} + \frac{c - 1}{v_m c} (p/p_0) \quad (2.8)$$

In both models, parameter v_m and c are vital to evaluate the adsorption isotherm and pore structure. Parameter v_m refers to monolayer capacity, and it is crucial to estimate specific surface area. Specific surface area is surface area normalized by adsorbent mass. Due to v_m is expressed as the volume of gas, equation can be expressed as below:

$$A_s = \frac{v_m a_m L}{22414} 10^{-18} \quad (2.9)$$

where A_s is the specific surface area (m^2/g); a_m is the molecular cross-sectional area (0.162 nm^2 for nitrogen at 77K); L is the Avogadro constant $22,414 \text{ cm}^3/\text{g}$ is the molar volume for ideal gas at standard temperature and pressure (STP).

For the shale samples, the Langmuir model does not work for calculating v_m , where the horizontal intercept gives monolayer volume (v_m). There is a significant discrepancy with experimental data and gives a higher value than the actual value. Compared with Langmuir model, the BET model is more suitable for calculating v_m for the shale samples. To compute v_m and c , the classic method is to transform the equation to linear form, and then fit the data at

the beginning of isotherm to obtain the slope and intercept. This method is straight forward. However, how to select the fitting range is a challenge, because the transformed experimental data is not a straight line. There are different ways to select an appropriate linear range. The classic linear range is between 0.05 and 0.35 (Brunauer et al., 1938). However, due to the specification on the samples, this classic range cannot be used anywhere. In this study, another approach proposed by Rouquerol et al., 2007 is used to find the best linear fitting range more suitable for microporous adsorbent when using BET equation. An example is shown in Figure 2.10. Using this approach to select the fitting range, monolayer volume (v_m), c and specific surface area (A_s) are calculated for the six samples (Table 2.3). Computed results show that A_s is relatively small for organic-lean Mahantango 1 and 2 samples. For the more organic-rich Marcellus Shale, specific surface area increases from the sample of upper Marcellus to lower Marcellus 1. Sample of upper Marcellus has relative lower A_s value and is close to the value of Mahantango 2. Samples of middle Marcellus, lower Marcellus 1 and 2 have relative higher values of A_s . We found that specific surface area has a positive relationship with TOC content (Figure 2.11). Based on the analysis, shale with higher TOC content, such as lower Marcellus Shale, has a large surface area. In shale reservoir, gas exists primarily in form of adsorbed gas. It suggests that lower Marcellus Shale have potential to store more gas than the middle and upper Marcellus Shale.

Figure 2.10. Choice of fitting range (highlighted by red dots) for BET equation using sample of upper Marcellus as an example.

Table 2.3. Computed parameters using BET model for six shale samples.

Samples	c	v_m (cm ³ /g)	A_s (m ² /g)
Mahantango 1	263	4.23	18.42
Mahantango 2	318	4.49	19.53
upper Marcellus	344	4.85	21.12
middle Marcellus	496	10.09	43.93
lower Marcellus 1	864	11.57	50.38
lower Marcellus 2	394	12.71	55.31

Figure 2.11. Relationship between specific surface area and TOC content.

Micropores are extremely small and usually no more a few molecular diameters in width. Pure microporous solids lead to a Type I isotherm, which is characterized by a steep slope in the initial part of the isotherm and a plateau as relative pressure approaches one. Micropore volume is calculated using a t-plot that is based on the concept of standard isotherms. Calculated micropore volume is shown in Table 2.4. It is obvious that samples of the Marcellus Shale especially for lower Marcellus Shale have much larger volumes of micropores.

Table 2.4. Micropore volume computed using t-plot.

Samples	Micropore Volume (cm³/g)
Mahantango 1	0.001454
Mahantango 2	0.001861
upper Marcellus	0.002382
middle Marcellus	0.0063
lower Marcellus 1	0.010945
lower Marcellus 2	0.010224

Comparing micropore volume with rock components, we found that a negative relationship exists between clay and micropore volume (Figure 2.12a). In contrast, micropore volume has a positive relationship with the kerogen volume (Figure 2.12b). It suggests that kerogen may be a main factor that results in increase of micropore in shale. In addition, micropore volume also has a positive relationship with the TOC (Figure 2.12c). This relationship agrees with the results from other studies that high TOC content have more micropores (Ross and Bustin, 2009; Loucks et al., 2012; Yang et al., 2014; Liu et al., 2015). Based on these observations, it suggests that the Marcellus Shale with a large volume of kerogen or high TOC content has more micropores. These micropores are formed in the organic matter as kerogen breaks down and transforms to hydrocarbons.

(a)

(b)

(c)

Figure 2.12. Relationships between micropore volume and (a) clay (v%), (b) kerogen (v%), and (c) TOC content (wt%).

In addition, we found that increased adsorbed quantity is related to high amount of micropores. Samples of Mahantango 1 and middle Marcellus are selected to make a comparison, because they have similar isotherm but different adsorbed quantity. Besides, they have similar mineral composition except for the difference in kerogen and illite volume (Figure 2.13). In the plotted adsorptive branch of isotherm for these two samples (Figure 2.14), the orange curve is the result of subtraction of two isotherms. This new curve is steep at initial part and has a relative horizontal plateau, which is similar to a Type I isotherm. It suggests that isotherm of the middle Marcellus could be obtained by summing the isotherm of Mahantango 1 with the Type I isotherm which is character of microporous solid. To test this hypothesis, the Langmuir equation is used to simulate the Type I isotherm based on subtracted curve. Summing the simulated curve to Mahantango 1, the green curve approximates the original curve (red dashed curve). The coefficient of correlation is 0.989, and it indicates the high similarity between these two curves, and that the isotherm of the Marcellus Shale is composite isotherm. Moreover, higher adsorbed quantity of the middle Marcellus could be explained as a result of a simple increase in micropore volume, which is contributed by increase of kerogen or high TOC content.

TOC content is an important parameter to predict the quality and in-place volume of a shale gas reservoir such as the Marcellus. It is not only because it is chemical index to assess the quality of source rock, but also it has close relation with surface area and micropore providing the pore space for gas storage. In other words, the Marcellus Shale with high TOC content has high gas storage capacity.

Figure 2.13. Rock component in volumetric percentage for sample Mahantango 1 and middle Marcellus.

Figure 2.14. Isotherm simulation using samples of Mahantango 1 and middle Marcellus.

Using TOC content as a proxy for shale gas storage capacity, TOC is calculated using proposed method for other three wells located in Greene County (G#24715), Harrison County (H#05106) and Webster County (W#00104) respectively (Figure 2.15). The thickness of the Marcellus Shale in the Greene County well is 134ft. Although the Marcellus Shale in this well is thicker than that in other wells, TOC has a considerable variation in the Marcellus interval. The base of the Marcellus Shale has very high TOC content (10%). Due to large thickness (26ft) of high TOC layer, the lower part of Marcellus in the Greene County could have higher storage capacity for shale gas. In the Monongalia County, TOC content is relatively high at middle and lower Marcellus Shale with thickness of 6ft and 12ft respectively. Thickness for these two parts is relatively thinner than that in the Greene County. In the Harrison County, there are three parts in the well with the presence of high TOC content that is close to 10% with thickness of about 6ft, 8ft and 20ft respectively, suggesting that gas storage capacity is high in this region. In the Webster County, the thickness of Marcellus Shale is 50ft and is the thinnest of the four wells, but TOC content is consistently high in the middle part of the Marcellus Shale. The large thickness with high TOC content suggests large volume of gas stored in the micropores, and high storage capacity. Based on observations of these four wells, the Marcellus Shale in the Green County and Harrison County has relatively higher storage capacity because of large thickness of high TOC content.

Figure 2.15. Cross section generated by four wells showing predicted TOC content for the Marcellus Shale. Wells from left to right are located in Greene County (G#24715), Monongalia County (MIP3H), Harrison County (H#05106) and Webster County (W#00104).

2.4 Summary

Both well logging and nitrogen adsorption experiment data from well MIP3H are used to study pore characterization of the Marcellus Shale. A nitrogen adsorption experiment is conducted for six shale samples, which were selected from the organic-lean Mahantango Formation and the organic-rich Marcellus Shale. Isotherms of the Marcellus Shale belong to a composite isotherm, which has features of Type I, Type II and Type IV isotherms. Based on features of low slope of the hysteresis loop and unlimited adsorbed amount approaching saturation, isotherms of the Marcellus Shale are more similar to the Type H4 hysteresis loop. It suggests slit-like pores were developed in the Marcellus Shale. HFF model is used to analyze pore structures. The results show that the Marcellus Shale has more complex pore structure and rougher surface than the Mahantango Formation. Fractal dimension has positive correlation with TOC content. This result indicates that higher TOC content results in a more complicated pore structure. In addition, shale samples with higher TOC content have large specific surface area, which could store more gas in the shale. Moreover, micropores have positive relationship with TOC content and kerogen, and a negative correlation with clay minerals. By employing Langmuir model and BET model, simulated results indicate that higher adsorbed quantity is best explained as a result of increase of micropore volume that is contributed by an increase of kerogen or TOC content. Therefore, TOC content is a critical parameter to understand in-place gas storage capacity.

3. Estimation of “Fracability” of the Marcellus Shale

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Abstract

Hydraulic fracturing is critical to economic production of shale oil and gas from unconventional reservoirs. Success of completion is closely related to gas production. The brittleness index is widely used as a measurement of ability to hydraulic fracture a unit. However, the index is not a unique and explicit indicator for estimating “fracability”. In the Marcellus Shale of our study area, a discrepancy exists between the brittleness index calculated from mineralogy and the elastic moduli calculated for sonic logs. In addition, the brittleness index does not explain why the large majority of microseismic events were generated well above or below the Marcellus Shale. Three other factors contribute to the efficiency of hydraulic fracture stimulation. One is the presence of pre-existing natural fractures. Natural fractures, measured and interpreted from the formation micro-imager (FMI) log, show that fractures developed in similar patterns with high dip angle in the Marcellus and overlying Mahantango shale units, and are favorable for vertical fracture propagation. The second factor is reservoir geomechanical characterization. The Marcellus Shale has an obvious presence of overpressure. According to the study on stress state using a Mohr’s circle, overpressure in the Marcellus Shale increases the possibility of frictional sliding of pre-existing fractures especially at the lower value of least principal stress, and some fractures at certain dip angles will remain open, although some of them are in non-active state. Unconfined compressive strength (UCS) is used to estimate rock strength in overpressure strata. The result calculated from empirical equations shows that the Marcellus Shale has significantly lower rock strength, which continues up into the Mahantango Formation, and explain vertical hydraulic fracture growth. The third factor is an effective fracture barrier. The Onondaga Limestone below the Marcellus Shale serves as fracture barrier in our study area. We found that fracture barrier with relative high effective minimum horizontal stress and sufficient thickness is effective in preventing the hydraulic fractures growing downward to other formations.

3.1 Introduction

To optimize hydraulic fracturing, completion quality is an important factor that contributes to maximizing shale gas production. In recent years, brittleness has been widely used in industry to evaluate the ability to hydraulic fracture a shale gas reservoir (Jarvie et al., 2007; Rickman et al., 2008; Wang and Gale, 2009; Kundert and Mullen, 2009; Slatt and Abousleiman, 2011; Jin et al., 2015). Brittleness has been estimated using data either from lab analysis or from well logging. Jarvie et al. (2007) reported that a high amount of quartz is an indication of brittleness in terms of mineral components. Wang et al. (2009) believed that dolomite should also be considered as a brittle part in addition to quartz, while organic matter would increase ductility. In addition to the study of brittle mineral components, characteristics of elastic moduli are also used to distinguish brittle and ductile shale. Rickman et al. (2008) indicated that brittle rock has higher Young’s modulus and lower Poisson’s ratio, and considered brittleness as an average

of normalized Young's modulus and Poisson's ratio. In our study area, the brittleness index calculated from minerals is not in accordance with that calculated from elastic moduli (detailed methods shown in appendix 2).

The study focuses on the well MIP3H located in Monongalia County, West Virginia and is part of the Marcellus Energy and Environment Lab (MSEEL) (Figure 3.1). Both the pilot hole and horizontal well of MIP3H have comprehensive data including drilling, well logging and microseismic data. Other four wells are located in Greene County (G#24715), Harrison County (H#05106) and Webster (W#00124 and W#00104), which are used as comparison. In the MIP3H, two horizontal wells drilled toward the northwest were monitored and logged with microseismic and fiber-optic distributed acoustic sensing (DAS) and distributed temperature sensing (DTS) (Figure 3.2). The vertical pilot hole of the MIP3H is used to compute the brittleness index (Figure 3.3). Brittleness indexes calculated from Jarvie et al. (2007) and Wang et al. (2009) show nearly identical trends. Shale units of the Marcellus Shale and Mahantango Formation are more brittle than limestone units of the overlying Tully Limestone and underlying Onondaga Limestone. On the contrary, the brittleness in terms of elastic moduli shows higher values on the Tully and Onondaga limestone units, while the Marcellus Shale is more ductile. This contrast between mineralogical brittleness and brittleness measured from elastic moduli does not provide an explicit characterization of brittleness.

Figure 3.1. Map view of wells used in this study. The study focuses on the MIP3H in the Monongalia County. Other wells are used as comparison.

Figure 3.2. Map view of two horizontal wells at the Marcellus Shale Energy and Environment Lab (MSEEL) with microseismic events recorded during stimulation of the MIP3H and MIP5H.

Figure 3.3. Brittleness index calculated for the MIP3H pilot hole from the Tully Limestone to the Onondaga Limestone adopting methods from Jarvie et al. (2007) (BI_JARVIE, Track 2), Wang et al. (2009) (BI_WANG, Track 3), and elastic moduli following Rickman et al. (2008) (BI_E, Track 4). Gamma ray log is shown in Track 1.

Based on observation of microseismic data in study area, most of events are well above the top of the Marcellus Shale with the center of radiated microseismic energy located 160 ft (49 m) above the perforation clusters (Wilson et al. 2018). Dependent on the well, microseismic events located within the Marcellus Shale reservoir are 20% for the MIP3H and 15.8% for the MIP5H. For both horizontal wells, the majority of microseismic events fall into the overlying formations (Figure 3.4). For the MIP3H, a large number of events occur in the Mahantango Formation, which is characterized by organic-lean shale. For the MIP5H, most of events are located above the Tully Limestone and in the Mahantango Formation. In order to explore the factors that influence fracturing and result in microseismic events, the presence of pre-existing natural fractures, reservoir geomechanical characterization and fracture barrier are examined in this study.

Figure 3.4. Histogram of microseismic events by stratigraphic unit for all stages of the MIP3H and MIP5H. The majority of microseismic events occur in stratigraphic units above the Marcellus Shale.

3.2 Natural Fractures and Fracture Density

FMI (full-bore formation microimager) logging was conducted for the vertical pilot hole of the MIP3H to detect fractures. From the Tully Limestone to the Onondaga Limestone, 71 fractures were identified. P32 fracture density, which is area of fracture over the volume, is plotted with stereonets in Figure 3.5. Stereonets show fractures orientation and dip for different depth ranges. In the Onondaga Limestone, no fractures were observed. In the Marcellus Shale, most fractures have a high dip angle (nearly vertical) with a dominant east-northeast strike (N87E for healed fractures). Based on P32 fracture density plot, the highest density of fractures is located at the middle part of the upper Marcellus, and fractures are distributed almost evenly through the middle Marcellus. Fractures were not observed at the carbonate separating the middle and lower Marcellus. A significant number of fractures were also not observed in the lowest parts of the Marcellus. In the Mahantango Formation, fractures developed similar to the Marcellus at a very high dip angle with dominant east-northeast direction. At the bottom of the

Mahantango, the P32 log indicates that fractures are persistent across the contact with the Marcellus Shale. Fractures gradually decrease in the upper Mahantango Formation approaching the Tully Limestone. In the Tully Limestone, only three fractures appeared with middle to high dip angle and northeast strike.

Based on the FMI observations, fractures developed with similar orientation and high dip angle in the two shale units of the Marcellus and Mahantango. These fractures may be continuous or could be easily connected when they are activated during hydraulic fracturing, which may result in activation of fracture in the Marcellus Shale and moving up into the Mahantango Formation.

Figure 3.5. Fracture density P32 for the MIP3H pilot hole along with stereonet for fractures in the different ranges of the Tully Limestone, Mahantango Formation and Marcellus Shale.

3.3 Geomechanical Characterization

Hydraulic fracturing involves both the processes of failure of rock matrix and activation of pre-existing natural fractures in the subsurface. These two processes are closely related with pore pressure in terms of the effective stress law, which is expressed by difference between principal stress and pore pressure. A rock may be destabilized by increasing pore pressure in relation to failures (Fjar et al., 2008). Rock failure can be defined by a Mohr's circle and failure envelope. Increasing pore pressure will result in Mohr's circle moving left and increasing the chance of intercepting with failure envelope. It means that failure can be generated or activated during process of increasing pore pressure in this study.

3.3.1 Pore Pressure Prediction

Based on definition, pore pressure represents a hydraulic potential with regard to earth's surface, and it assumes that pores are interconnected. Therefore, in a normal condition, the pore pressure at a certain depth is equal to hydrostatic pore pressure. If pore pressure is larger than hydrostatic pore pressure, the phenomenon is described as overpressure. Conversely, less than hydrostatic pore pressure will be described as under-pressure. To predict pore pressure, sonic and resistivity log data are commonly used (Hottmann and Johnson, 1965; Eaton, 1975; Bowers, 1995). The normal trend of sonic log should be interpreted as a steady increase of the compressional wave velocity with depth, while for resistivity log, the normal trend is expressed as resistivity increasing. The rationale behind these increases in sonic compressional velocity and resistivity is closely related with decrease of porosity under compaction with depth. In the pilot hole of the MIP3H, well log curves of compressional wave velocity and resistivity show a major turning point is around a depth 4600ft (1402m) for both curves (Figure 3.6). Below the point, velocity is deviated from the normal trend and decreases with depth, which is the characteristic of overpressure. Different from velocity curve, resistivity decreases with depth first and then increases at deeper depth below the turning point. One reason may be resistivity log is sensitive to hydrocarbons which could cause an increase of resistivity. Because of the hydrocarbon effect, the resistivity curve is influenced by presence of hydrocarbons in addition to porosity. Therefore, sonic well log is used to predict pore pressure.

Figure 3.6. Variation trend of compressive wave velocity and resistivity well log curves in the pilot hole of the MIP3H.

A linear relationship exists between compressional wave velocity and depth, as velocity should increase with depth (Slotnick, 1936). Pore pressure is predicted using a method proposed by Eaton (1975), and the adapted form in velocity is shown as follows:

$$P_p = S_v - (S_v - P_h) \left(\frac{v_{\log}}{v_n} \right)^x \quad (3.1)$$

where S_v is the vertical stress (psi); P_h is the hydrostatic pore pressure (psi); $v_{\log}$ is the sonic velocity of compressional wave from log data; v_n is the sonic velocity of compressional wave from the normal trend; x is the constant which is determined empirically. Mud weight in this well is used to constrain predicted pore pressure, because it serves as a role to balance pore pressure when drilling the well. In the condition of drilling in balance, it will reflect underground pore pressure in a certain degree. Therefore, calculated pore pressure should be close to pore pressure converted from mud weight. Based on this, exponent x is 1.0 for this well.

In the pilot hole of the MIP3H, predicted pore pressure is shown in Figure 3.7. Shale units of

the Marcellus and Mahantango units display the presence of overpressure. The overpressure increases the deviation of pore pressure from hydrostatic pressure and begins to approach vertical stress. Effective stress (difference between S_v and P_p) is reduced from the expected normal trend. In the range from the Tully Limestone to the Onondaga Limestone, the highest deviation of pore pressure is located at the Marcellus Shale (Figure 3.7c). Pore pressure for the Mahantango Formation is lower than that in the Marcellus Shale, but it increases with depth and approaches pore pressure of the Marcellus Shale at the contact of these two shale units. For the Tully Limestone and Onondaga Limestone, pore pressure drops to approximately hydrostatic pressure.

Figure 3.7. Pilot hole of the MIP3H showing (a) compressive wave velocity plotted with depth, (b) pore pressure calculated from compressional wave velocity, and (c) pore pressure (P_p) compared with pore pressure from mud weight (P_m), hydrostatic pressure (P_h) and vertical stress (S_v).

3.3.2 Mohr's Circle Analysis

Activation of pre-existing open and healed fractures is one situation involved in hydraulic fracturing. Although some natural fractures are healed by calcite, they are weak and easy to be activated during the hydraulic fracturing. Based on Amonton's law for frictional sliding, a fracture plane will be activated when the ratio of shear to normal stress approaches the

coefficient of friction (μ). Dependent on the study of the coefficient of friction on wide range of rocks, the lower bound value of 0.6 is used in this study (Byerlee 1978).

In the MIP3H, values of minimum horizontal stress (S_{hmin}) are from instantaneous shut in pressure (ISIP) in hydraulic fracturing. ISIP was measured in the surface, and was transformed into subsurface value. There are total 21 ISIP recorded during hydraulic fracturing (Figure 3.8). Comparing these S_{hmin} with corresponding values of S_v , shows that all S_{hmin} are smaller than S_v . Therefore, the possible stress regime is normal or strike-slip faulting stress regime rather than reverse faulting stress regime. Assuming a normal faulting stress regime in study area, greatest principal stress (σ_1) will be equal to vertical stress (S_v), and least principal stress (σ_3) will be equal to minimum horizontal stress (S_{hmin}), according to Anderson's classification of style of faulting (Anderson, 1951). In order to explore changes of Mohr's circle corresponding to different least principal stresses, values of maximum and minimum ISIP are selected for evaluation. Mohr's circles expressed by effective stresses are plotted with coefficient of friction (Figure 3.9). The blue circle is calculated using minimum ISIP, whereas the green circle using maximum ISIP. Figures 3.9a and 3.9b represent different conditions. In normal or hydrostatic pore pressure condition (Figure 3.9a), both circles do not touch the frictional sliding line. As a result, frictional sliding is not predicted to occur along pre-existing fractures. In the overpressure conditions observed in the Marcellus and Mahantango (Figure 3.9b), overpressure moves both circles to left. The blue circle intercepts with frictional sliding line, but the green circle is still under the line despite overpressure. The position of the circle relative to frictional sliding line illustrates that pre-existing fractures have propensity to be activated. Activation is not only affected by pore pressure, but also dependent on magnitude of least principal stress (ISIP in this paper). Therefore, the activation of pre-existing fractures is location based, and should be considered stage by stage. The study results show that under lower ISIP the Mohr's circle is more likely to touch the frictional sliding line. Moreover, the blue circle intercepted the line with two points, implying that pre-existing fractures will be activated in the range with dip angle between 41.3° and 79.6° . In order to make comparison between stress state and fractures, assuming fractures in the range of the Marcellus Shale interpreted by FMI from the MIP3H pilot hole reflect the general condition in the study area, they are plotted onto the blue circle (Figure 3.9b). Orange points are conductive (open) fractures, and blue points are resistive (healed) fractures. In total 32 fractures, 13 fractures are located above sliding line on Mohr's circle including 3 conductive fractures, and 19 fractures are located below the sliding line. It suggests that some fractures are active fractures in the extreme condition of minimum value of ISIP. In this condition, presence of overpressure in the Marcellus Shale may keep some fractures in certain dip angle open, although some of them are in a non-active state.

Figure 3.8. Histogram of instantaneous shut in pressure measured along the horizontal well MIP3H.

Figure 3.9. Mohr's circle with frictional sliding line showing (a) normal or hydrostatic

conditions for the vertical depth of the MIP3H, and (b) overpressure condition in the well as computed from logs and mud weights. Blue Mohr's circle describes minimum effective stress state, while green circle represents maximum effective stress state. Points on the blue circle are fractures observed from FMI log. Orange points are conductive fractures, while blue points are resistive fractures.

3.3.3 Rock Strength Prediction

In addition to activation of pre-existing fractures, another process is rock failure in hydraulic fracturing if rock matrix is treated as isotropic medium (i.e. without the influence of preferential zones of failure). Relating Mohr's circle, rock failure is described by a failure envelope. A linearized Mohr envelope defined by two parameters in terms of normal and shear stress. The one is coefficient of internal friction; the other is cohesion. As cohesion cannot be measured physically from experiments, unconfined compressive strength (UCS) is typically used to express rock strength. On Mohr's circle, UCS is expressed as value of σ_1 , when σ_3 is equal to zero. In the case of the MIP3H, pore pressure in the shale units is higher than hydrostatic pore pressure, which results in Mohr's circle moving to the left and effective least principal stress approaching zero. In this situation, UCS could be used to reflect the "fracability" under overpressure conditions. In the MIP3H, UCS is calculated using the empirical equations for shale and limestone summarized by Zoback (2010) (Table 3.1) and shown in Figure 3.10. UCS for limestone is used as a comparison and its "fracability" in the subsurface is subject to change as pore pressure drops to normal. The red curve is calculated based on its relationship with porosity, and shows a significant difference between the shale units and overlying and underlying limestone units. The blue curve relies on empirical relation to Young's modulus. The upper and middle Marcellus organic-rich shale units have the lowest strength, and the strength of lower organic-rich shale unit of the Marcellus is slightly higher. For the Mahantango Formation, rock strength is generally higher than the Marcellus with an upward increasing trend. It is worth noting that UCS of lower part of the Mahantango is close to that of the Marcellus at the boundary of these two units. Based on observations, it implies that the upper Marcellus and middle Marcellus are relatively easier to fracture. Given the similarity of UCS at the boundary of the Marcellus and Mahantango rock failure would be expected to grow upwards into the overlying units. This may explain the dominance of microseismic events above the Marcellus Shale along the horizontal wells of MIP3H and MIP5H.

Figure 3.10. Prediction of rock strength for shale and limestone sections along with unit tops. Red curve is UCS calculated from empirical relation with porosity, while blue curve is computed from relation with Young's modulus. The blue block highlights the limestone units underlying and overlying the shale units.

Table 3.1. Equations used to predict the UCS for shale and limestone from Zoback (2010).

Lithology	UCS (Mpa)
Shale	$0.0528E^{0.712}$
	$1.001\phi^{-1.143}$
Limestone	$0.4067E^{0.51}$
	$135.9\exp(-4.8\phi)$

*E: Young's modulus (MPa), ϕ : porosity (fraction).

3.4 Fracture Barrier

Fracture barriers are a crucial factor pertaining to success of hydraulic fracturing, because the hydraulic fractures can be constrained by fracture barriers in the target zone. In the study area of well MIP3H, the Onondaga Limestone underlying the Marcellus Shale serves as fracture

barrier and prevents hydraulic fractures growing downward to other formations, which can be observed in microseismic records (Figure 3.4). Based on the factors discussed above, the Onondaga Limestone lacks natural fractures. Besides, rock strength of the Onondaga Limestone is higher than that of the Marcellus Shale. In addition, effective minimum horizontal stress may play an important role on limiting hydraulic fractures.

In the isotropic medium, minimum horizontal stress can be predicted using the equation showing below (Thiercelin and Plumb, 1994):

$$S_{hmin} = \left(\frac{\nu}{1-\nu} \right) (S_v - \alpha P_p) + \alpha P_p + \frac{E}{1-\nu^2} \varepsilon_h + \frac{\nu E}{1-\nu^2} \varepsilon_H \quad (3.2)$$

where ν is the Poisson's ratio; E is the Young's modulus (psi); P_p is the pore pressure (psi); S_v is the overburden stress (psi); α is the Biot's elastic constant; ε_h and ε_H are the minimum and maximum horizontal strain.

Assuming few tectonic influence and taking the Biot's elastic constant as 1, the equation 3.2 can be simplified as:

$$S_{hmin} = \left(\frac{\nu}{1-\nu} \right) (S_v - P_p) + P_p \quad (3.3)$$

Minimum horizontal stress is computed by the simplified equation for the pilot hole of MIP3H and results shown in Figure 3.11. The computed results fall into the range of measured ISIP (Figure 3.8). It indicates that computed results are able to reflect minimum horizontal stress in the subsurface. Shale units especially the Marcellus Shale have relatively higher S_{hmin} than the Onondaga Limestone and Tully Limestone. However, shale units have overpressure that cannot be ignored. Effective minimum horizontal stress (S_d) is the difference between minimum horizontal stress and pore pressure. It is obvious that the Onondaga Limestone has higher effective minimum horizontal stress than the Marcellus Shale. Generally, hydraulic fractures propagate perpendicular to the minimum horizontal stress (Hubbert and Willis, 1957). Treatment pressure in the Marcellus Shale is enough to make the hydraulic fracture open and grow, but this pressure may not be effective for the underlying Onondaga Limestone. Therefore, the Onondaga Limestone is effective to prevent hydraulic fractures growing down. In addition to the Onondaga Limestone, the Tully Limestone also has a high effective stress. Besides, relatively high effective stress also appears at the boundary of middle Marcellus Shale and lower Marcellus Shale, which may be the presence of a carbonate bed. It suggests that limestone may be used as a parameter to predict a fracture barrier.

Under the Onondaga Limestone, the Huntersville Chert has low effective minimum horizontal stress, even lower than the Marcellus Shale. It suggests that fractures are easier to propagate in the Huntersville Chert than in the Marcellus Shale. The failure of completion of wells in the Webster County is an example that can be used to explain the importance of fracture barrier. The W#00124 was drilled as horizontal well to produce shale gas. However, it was failed to produce gas because hydraulic fractures were generated below the horizontal well and grew

into underlying formations based on the observation of microseismic events recorded along the horizontal well (Figure 3.12). Due to limited well logging data in W#00124, the adjacent well of W#00104 is used to compute the effective minimum horizontal stress. In Figure 3.13, the thickness of the Onondaga Limestone is 7ft, and it is thin layer. Besides, there is no significant contrast on effective minimum horizontal stress in the Onondaga Limestone compared to formations above and below. Therefore, the Onondaga Limestone in this region cannot serve effectively as fracture barrier. In addition, natural fractures are prevalent in the Huntersville Chert (Diecchio, 1985), thus it is more sensitive to pore pressure perturbation during the hydraulic fracturing, which results in hydraulic fractures growing down rather than staying within the Marcellus Shale.

Figure 3.11. Computed minimum horizontal stress (S_{hmin}) and effective minimum horizontal stress (S_d) for the pilot hole of MIP3H.

Figure 3.12. Microseismic events recorded for three stages along the horizontal well of W#00124.

Figure 3.13. Computed minimum horizontal stress (S_{hmin}) and effective minimum horizontal stress (S_d) for the well of W#00104.

To explore regional changes of fracture barrier, comparison of effective minimum horizontal stress are carried out for four wells from Greene County, Monongalia County, Harrison County and Webster County (Figure 3.14a). Effective minimum horizontal stress of the Onondaga Limestone from wells in the Monongalia County and Harrison County is significantly higher than that of the Marcellus Shale and the Huntersville Chert. This suggests that the Onondaga Limestone in these regions serves effectively as a fracture barrier. However, the Onondaga Limestone is very thin (Figure 3.14b) and no considerable contrast on effective minimum horizontal stress compared to overlying and underlying formation for the well in Webster County. Therefore, the Onondaga Limestone in the Webster County may lose its barrier effect.

(a)

(b)

Figure 3.14. (a) Effective minimum horizontal stress computed for the four wells in Greene County (G#24715), Monongalia County (MIP3H), Harrison County (H#05106), and Webster County (W#00104) from north to south. (b) Comparison of effective minimum horizontal stress of Onondaga Limestone.

3.5 Summary

Brittleness index is not a unique and explicit index of “fracability”. In our study area, brittleness indexes calculated from mineralogy and elastic moduli have significant discrepancies. The brittleness index cannot provide an explicit explanation for distribution of microseismic events. In order to explain this phenomenon, three factors of fracability are proposed in this paper. The first one is pre-existing natural fractures. Fractures are developed in similar patterns with high dip angle in the two shale units of the Marcellus and Mahantango. Conditions are favorable for fracture growth vertically upwards and may easily connect with each other. The second factor proposed is geomechanical characterization of the reservoir. According to the study of stress state using Mohr’s circle, overpressure in the Marcellus Shale increases the chance of activation of pre-existing fractures especially for the lower value of least principal stress, and it may maintain some fractures in certain dip angle open, although some of them are in non-active state. Unconfined compressive strength (UCS) may be a choice to estimate rock strength in overpressure strata. The result calculated from empirical equations indicates that the Marcellus Shale has significantly lower rock strength than the underlying Onondaga Limestone. Rock strength of the Mahantango is higher than the Marcellus and increases upwards. The difference of rock strength between the Marcellus and Mahantango is not great, which may cause hydraulic fractures to propagate upwards. The third factor is an effective fracture barrier. The Onondaga Limestone below the Marcellus Shale serves as a fracture barrier in our study area. We found that fracture barrier with relatively high effective minimum horizontal stress and large thickness is more effective to prevent the microseismic growing down to other formations.

4. Interpretation of Microseismic Characterization and its Implications to Shale Gas Production

Abstract

By observing the microseismic events recorded during hydraulic fracturing, we found that some basic microseismic characterization such as event number, dominant microseismic azimuth varies stage by stage. Microseismic events are examined by statistical methods of b-value and D-value. A combination of b-value and D-value can be used to interpret the activation of faults and natural fractures. By employing time-distance plot, presence of faults or natural fractures results in higher hydraulic diffusivity. Natural fractures and stress shadow have influence on distribution of microseismic events. Natural fractures in the local condition are easily activated. Moreover, they are present at a lower angle with azimuth of S_{Hmax} . It suggests that hydraulic fractures can be easily captured by these natural fractures, which would affect growth of hydraulic fractures. In addition, the stress shadow has a strong influence for adjacent stages, and the effect diverts the direction of hydraulic fracture growth. By applying stress shadow into unconventional fracture model (UFM), simulated hydraulic fractures agree with distribution of most microseismic events. The hydraulic fractures in the stress shadow grow towards the area of adjacent stage, which may be helpful to enhance production of the next stage. However, for the current stage, as fracturing is not enough to create more fractures in corresponding area, it may result in the lower production in the stage.

4.1 Introduction

Hydraulic fracturing has been widely used in the petroleum industry to extract hydrocarbons from unconventional reservoirs. Success of hydraulic fracturing varies case by case, and there are many factors that influence production. To evaluate success of hydraulic fracturing, microseismic monitoring plays an important role to monitor development of hydraulic fractures. Microseismic events represent micro-earthquakes detected by using both compression and shear waves recorded by arrays of receivers. Usually, microseismic events and their location are used to predict the location of fractures or estimate stimulated reservoir volume (SRV) which is a correlation parameter for hydrocarbon production (Mayerhofer et al., 2010; Wilson et al., 2016). However, not all pumping stages make the same contribution to the production. Based on the observation of our study well (Figure 4.1), microseismic events have a considerable variation stage by stage. First, histogram of microseismic events per stage reveals large variation along the horizontal well MIP3H (Figure 4.2). Total event number of stage 18 is almost 2000. In contrast, stage 28 has total event number less than 200. Filtered by formation surfaces, red columns represent number of events generated in the Marcellus Shale. Most of events are located in the Marcellus Shale. However, some stages such as stages 22, 23, 24 have lower stimulation efficiency, and they have a lot of out of zone events. The variation in microseismic event number does not appear to be related to the treatment (Figure 4.3). There is no significant fluctuation on total fluid used in treatment. For total proppant, except middle

stages from stages 13 to 19 have large variation, the total proppant used in stimulation for the stages is similar. Second, dominant azimuth of microseismic events computed using location of middle perf as reference varies stage by stage, especially for the stages 20 to 28. In Figure 4.4, average dominant azimuth is 75° from stage 7 to stage 19, but dominant azimuth has considerable change from stages 20 to 28.

Figure 4.1. Map view of two horizontal wells and microseismic events records along the MIP3H.

Figure 4.2. Histogram of microseismic events along the horizontal well MIP3H.

Figure 4.3. Total fluid and proppant used in stimulation for MIP3H.

Figure 4.4. Microseismic dominant azimuth calculated using middle perf of each stage of horizontal well MIP3H.

In order to interpret the variation of microseismic characterization and explore its influence on shale gas production, b-value and D-value are calculated for microseismic statistical analysis. In addition, hydraulic diffusivity is used to examine the hydraulic conductivity. Moreover, variation of azimuth of natural fractures in the reservoir are examined. Combined with hydraulic fracture modeling, deviations in microseismic distribution can be explained by stress shadow, which may explain production differences along the horizontal well as recorded by production logging.

4.2 Microseismic Statistical Analysis

Geostatistical methods can be used to extract information from synthesized microseismic events. Two commonly used methods in geostatistical analysis are b-value and D-value, which represent the frequency of moment magnitude occurrences and spatial geometry of hypocenter locations respectively.

4.2.1 b-value

In our study, two methods are used to estimate the b-value. The one is in Gutenberg and Richter (1944) frequency magnitude relationship:

$$\log(N) = -bM + c \quad (4.1)$$

where N is the number of earthquakes with magnitude greater than or equal to the moment magnitude (M) occurring over some time frame; b is the absolute value of the slope of samples; and c is the intercept, which measures the sample size.

An alternative approach to computation of b-value was proposed by Aki (1965). The relationship treats magnitude as a continuous random variable shown as following equation:

$$b = \frac{\log_{10}(e)}{M_{av} - M_0} \quad (4.2)$$

where M_{av} is the average magnitude of the microseismic events; and M_0 is the minimum or the threshold magnitude associated with the data set.

4.2.2 D-value

D-value is fractal dimension characterizing the spatial distribution of event hypocenters. Grassberger and Procaccia (1984) proposed spatial correlation with the correlation integral method to quantify relations among the events, which is given by:

$$C(r) = \frac{2}{N(N-1)} N(R < r) \quad (4.3)$$

where $C(r)$ is the integral value; N is the number of events; and $N(R < r)$ is the numbers of event pairs separated in distance R smaller than r . The correlation integral will follow a power-law distribution with distance (r), if the distribution is fractal. The pertinent equation is:

$$C(r) \propto r^D \quad (4.4)$$

The correlation integral will have linear relationship with distance in logarithmic form, and D is the slope of the linear part in the relationship. For the value of D , value 0 represents a point, 1 is a line, 2 is a plane and 3 is a cluster.

The b-value is computed using two methods for every stage along the horizontal well MIP3H (Figure 4.5). The b-values have average value of 1.9. Stages with higher b-value indicate a large number of events with low moment magnitude events and vice versa. A comparison of moment magnitude between higher and lower b-value are shown in Figure 4.6. For stage 11, the b-value in average of the two methods is 1.3, and most events have moment magnitude in the range of -2.4 to -2. For stage 17 with b-value of 2.2, most events have moment magnitude in the range of -2.6 to -2.2. This indicates that stage 17 has more small events than stage 11. These small events may be related to shear failure on pre-existing natural fractures. By studying

the relationship of different tectonic stress regime and b-value, Schorlemmer et al. (2005) found a correlation between them. Based on proposed classification, b value greater 1 is correlated to normal faulting or extensional stress regime. The b-values in our study are all above 1, and it suggests that events are generated in the extensional stress regime, which corresponds to hydraulic fractures created by process of hydraulic fracturing.

Figure 4.5. b-values computed using the least squares (red dots) and Aki (1965) (green dots) methods are shown for each stage along the horizontal well MIP3H. D-values are shown in purple squares. Histogram of event number in each stage is plotted as reference.

Figure 4.6. Histograms of moment magnitude for stage 11 (left) and stage 17 (right) from MIP3H.

Most of stages in the MIP3H have D-values greater than 2.5, suggesting that the spatial distribution of microseismic events for these stages is more similar to a cluster, which indicates a complexity of distribution of microseismic events. For stage 13, 15, 16, D-values are 2.2, 2.3, and 2.2 respectively. The microseismic spatial distribution for these three stages is more similar to a plane. Microseismic spatial distribution may be influenced by local structure. If it has appearance of faults around the well, faults may be reactivated during the hydraulic fracturing, and then microseismic events caused by fault activation would follow the trace of the fault, thus the spatial distribution is more like a plane. For the cluster spatial distribution, small scale natural fractures may induce the complexity.

Combined results of b-value with D-value indicate three conditions based on the observations shown in Table 4.1. In the condition 1, both b-value and D-value have relative low value, such as stage 13, 15, 16, indicating that microseismic events of these stages have increased occurrence of large magnitude events and their spatial distribution is more similar to a plane. Moment magnitude has a positive linear relationship with fracture length in semi-log plot (Wells et al., 1994). Based on this empirical relationship, the larger moment magnitude represents large scale events, which may be the result of fault activation, and a more planar microseismic spatial distribution. Hydraulic fracturing a shale gas reservoir, activation of faults has two implications. It is true the activation of faults will enlarge the area of hydraulic fracturing and then enlarge the production. However, the scale of the faults is unknown, and activation of a large-scale fault may extend out of target zone, which would cause a lot of out of zone events and result in low efficiency of hydraulic fracturing the reservoir. This feature could be used to explain out of zone events. In the histogram of microseismic event number (Figure 4.2), the percentages of out of zone events for stage 13, 15, 16 are 19.2%, 56.5%, and 52.2% respectively. Although stage 13 has less out of zone events, both stage 15 and 16 have the most of events out of zone. In the condition 2, b-value is still relatively low, but D-value is relatively high. This suggests that large events such as fault activation may exist, but randomly distributed natural fractures may have larger influence, which results in more complex spatial distribution. In condition 3, both b-value and D-value are relatively high, indicating that most of events are small events, and spatial distribution is complex and more proximate to a cluster. It suggests that natural fracture play a dominant role in this condition.

Table 4.1. Three conditions based on observation of b-value and D-value.

Condition	b-value	D-value	Stage	Explanation
1	relative lower value ($b < 2$)	relative lower value ($D < 2.5$)	13,15,16	large events
2	relative lower value ($b < 2$)	relative higher value ($D \geq 2.5$)	9,10,11,12,14, 18,19,20,23,24	large events and small events
3	relative higher value ($b \geq 2$)	relative higher value ($D \geq 2.5$)	7,8,17,21,22, 25,26,27,28	small events

4.3 Hydraulic Diffusivity

In hydraulically induced seismicity, a triggering front is a permeability related term, which was induced by Shapiro et al. (1997) with the concept of pore pressure diffusion in the isotropic and homogeneous poroelastic medium. The relationship of hydraulic diffusivity and triggering front follows the equation shown in below:

$$r(t) = \sqrt{4\pi\alpha t} \quad (4.5)$$

where r is the location of pressure triggering front at time t ; α is the scalar hydraulic diffusivity or trigger front diffusivity (m^2/s); and t is the time elapsed since start of injection.

For the selected value of the hydraulic diffusivity, the distance of most microseismic events must smaller than the curve given by the selected value following the equation. It means that this curve serves as upper bound of these microseismic events. An example of microseismic triggering front is shown in Figure 4.7. In stage 15, the hydraulic diffusivity $\alpha=1.9 \text{ m}^2/\text{s}$ makes a good separation for dense events below and sparse events above the curve. These scattered events above the curve indicate some events occurred earlier compared with their distances. It suggests that faults or pre-existing natural fractures are triggered during the hydraulic fracturing. This predicted result supports the inferences derived from b-value and D-value.

Figure 4.7. Time-distance plot of microseismic events contoured by hydraulic diffusivity $\alpha=1.9 \text{ m}^2/\text{s}$ for stage 15 in MIP3H.

Another example is stage 22 as shown in Figure 4.8. Stage 22 is special because this stage was pumped twice (Figure 4.8a). In this stage, hydraulic fractures were created during the first treatment, and then hydraulic fractures were opened again, and extend further. Based on hydraulic diffusivity chosen to include most of events, these two pumping stages have the hydraulic diffusivity $\alpha=1.6 \text{ m}^2/\text{s}$ and $\alpha=3.7 \text{ m}^2/\text{s}$ respectively, meaning that they are not following the same diffusivity. For the second pumping stage, $\alpha=1.6 \text{ m}^2/\text{s}$ was also plotted in

Figure 4.8c. Hydraulic diffusivity of $1.6\text{m}^2/\text{s}$ is more in line with the trend of microseismic events. Different with events shown in Figure 4.7, out of curve events in stage 22 are more intensive. It indicates that there are numerous events occurring before the triggering front ($1.6\text{m}^2/\text{s}$). It suggests that they may be the activation of hydraulic fractures created in the first pumping rather than just random distributed natural fractures. This phenomenon indicates two things occurred during the second pumping. First, old hydraulic fractures were opened and filled with proppants again. Second, new hydraulic fractures were created. This kind of treatment may benefit production, because second pumping may extend the fractures and refilled proppants may keep fractures wider to ensure production over longer durations.

(a)

(b)

(c)

Figure 4.8. Treatment data (a) and time-distance plot of microseismic events (b) (c) for stage 22 in MIP3H.

4.4 Fracture Analysis

Generally, hydraulic fractures propagate perpendicular to the orientation of the least principle stress (Hubbert and Willis, 1957). Local orientation of maximum horizontal stress (S_{Hmax}) and minimum horizontal stress (S_{Hmin}) can be determined using induced fractures and breakouts observed in the image log in the vertical well. In our vertical well, breakouts occurred in the shallow depth (3074ft-5244ft) above the Marcellus Shale, while induced fractures occurred in the depths, which are in the vicinity of the Marcellus Shale (6800ft-7739ft). Azimuths of breakouts and induced fractures were plotted in a rose diagram (Figure 4.9). Generally, breakouts occur at the azimuth of minimum horizontal stress, while induced fractures occur at

the azimuth of maximum horizontal stress in a vertical well. Although breakouts and induced fractures are located far away from each in depth, the dominant azimuths are 90 degrees apart. The dominant azimuth of induced fractures falls into the range of 61° to 70° , and the value 65° is used as the azimuth of S_{Hmax} . Usually, the dominant azimuth of microseismic events should be close to the azimuth of S_{Hmax} . However, we observed a considerable azimuth variation from stage 20 to 28 (Figure 4.4). For this part of study, we focused on stage 20, 21, 22, 23, which has abrupt change on microseismic azimuth for these four stages. Microseismic dominant azimuth is 95° for both stage 20 and 21, while it is 55° for stage 22 and 23. On the observation of microseismic events in 2D window, we found that a group of microseismic events in stage 20 and 22 deviates from their perforation clusters at a high angle (Figure 4.10). For microseismic events of stage 20, the diverged group (in the red circle) is located at the area of stage 21 and 22. For events of stage 21, the diverged group is close to stage 23. Different with these two stages, there is no obvious deviation on stage 22. For stage 23, although there is no clear deviation among the cluster, part of events do occur in the previous stage.

Figure 4.9. Rose diagram shows Induced fractures (N=16) and breakouts (N=17) occurred in the vertical well.

There are two possible reasons to explain this variation. One is influence of natural fractures, and the other is stress. Natural fractures were measured and identified along the horizontal well. Natural fractures of stage 20, 21, 22, 23 have a common trend toward east-northeast (Figure 4.11). There is a high number of natural fractures observed along stage 20. The azimuth of this stage has a wide distribution, and the dominant azimuth falls into the range between 71° to 80° . Stage 21 has two patterns of natural fractures. One primary pattern has azimuth falling into the range of 61° to 70° , while the other pattern has dominant azimuth in range from 101° to 110° . Stage 22 has a narrow azimuth distribution, and the dominant azimuth is between 61° to 70° . For stage 23, the fractures are more complex with various azimuths, but there is no significant change on dominant azimuth, which is in the range from 71° to 80° . Previous studies of interaction between hydraulically induced fractures and pre-existing natural fractures indicates that hydraulic fractures are likely to cross the pre-existing natural fractures at high angles of approach and high differential horizontal stress, while hydraulic fractures are likely to be

diverted or arrested in other conditions (Blanton et al., 1982; Warpinski et al., 1987). Comparing azimuth of S_{Hmax} and azimuth of the pre-existing natural fractures, fractures from these four stages present low angles with the azimuth of S_{Hmax} , especially for those fractures in the dominant azimuth. As a result, hydraulic fractures are easily arrested or diverted by natural fractures. Comparing these four stages, only stage 22 has more uniform natural fractures, whereas the other three stages have wider azimuth distribution. In addition, among these stages, stages 20 and 21 have more numerous natural fractures, suggesting that these two stages should be expected to have a more complex microseismic spatial distribution (Figure 4.10).

Based on the Mohr's circle analysis (Figure 4.12), Mohr's circles of stage 20, 21, and 22 cross the frictional sliding line, indicating natural fractures in these four stages are more likely to be activated due to changes in local stress condition. Plotting natural fractures onto the corresponding circles, we observed that a few natural fractures are active in stage 20 and 21. For the other two stages, although fractures are not in active status, increasing pore pressure during the hydraulic fracturing can activate the fractures. Active pre-existing natural fractures could serve as conduit for the fluid, which may cause the fracture growth diverting from the S_{Hmax} direction.

Figure 4.10. Map view of microseismic events for stages 20, 21, 22, and 23 in the MIP3H.

Figure 4.11. Rose diagrams show natural fracture azimuth for stages 20, 21, 22, and 23 in MIP3H.

Figure 4.12. Mohr's circles with frictional sliding line showing status of natural fractures for stages 20, 21, 22, and 23 in the MIP3H.

4.5 Stress Shadow

For deviated microseismic events such as appearing in stages 20 and 21, the stress shadow may be another contributing factor influencing the microseismic spatial distribution. The stress shadow is a phenomenon induced by hydraulic fracturing, and it appears as interaction among hydraulic fractures especially for those in close proximity. The effect of stress shadow is a superposition of induced stress and adjacent stress. The stress shadow affects the growth of hydraulic fractures and alters the local stress field (East et al., 2004; Kresse et al., 2013). A simple model is widely used to describe the effect of stress shadow (Warpinski et al., 1989; Soliman et al., 2008; Roussel et al., 2011; Vermilyen et al., 2011). In a homogeneous isotropic elastic media, the stress field around an infinitely long crack in 2D plane (Figure 4.13) can be expressed using analytical equations shown below (Sneddon, 1946; Sneddon and Elliott, 1946):

$$\sigma_a = -p \left\{ \frac{L}{\sqrt{L_1 L_2}} \times \cos[\theta - 0.5(\theta_1 + \theta_2)] - 1 \right\} \quad (4.6)$$

$$\sigma_b = p \left\{ \frac{L \sin \theta}{h/2} \left(\frac{h^2/4}{L_1 L_2} \right)^{1.5} \times \sin[1.5(\theta_1 + \theta_2)] \right\} \quad (4.7)$$

$$\sigma_x = \sigma_a - \sigma_b \quad (4.8)$$

$$\sigma_y = 2\mu\sigma_a \quad (4.9)$$

$$\sigma_z = \sigma_a + \sigma_b \quad (4.10)$$

where L , L_1 , L_2 are the distances shown in Figure 4.13; θ , θ_1 , θ_2 are the corresponding angles; h is the height of the crack; μ is the Poisson's ratio; p is the internal pressure or net pressure; σ_x , σ_y , σ_z represents the magnitude of minimum horizontal stress, maximum horizontal stress and vertical stress. In the calculation, Poisson's ratio is 0.2.

Figure 4.13. Geometry of crack in a 2D plane (modified after Warpinski et al., 1989).

Based on this model, the relationship induces two horizontal stresses in the center of crack and distance as shown in Figure 4.14. The stresses are normalized by internal pressure, and the distance is normalized by half-height of the crack. In Figure 4.14, both stresses decay with increasing distance from the center of the crack. In this model, the induced minimum horizontal stress has most apparent stress shadow effect for the nearby surrounding rocks. As distance increases, the induced S_{hmin} decreases rapidly, especially at distances smaller than a height of the crack. Assuming the fracture height is 250 ft based on the observation on the microseismic events from our study well, the distance of next single planar fractures are located at 220 ft, 440 ft, and 660 ft (based on average length of stages in our well) shown as purple dots on the horizontal axis in Figure 4.14. For hydraulic fracture induced stresses, a fracture at distances of 220 ft (67m) has a relatively large stress shadow effect, especially for S_{hmin} . Fractures at a distance of 440 ft (134m) can be influenced by the stress shadow, but the effect is relatively small. For a fracture at a distance of 660 ft (200m), the stress shadow effect is low enough to be ignored. Therefore, the stress shadow could influence adjacent stages in our study well.

Besides, comparing the induced S_{hmin} and S_{Hmax} , there is a considerable difference between them, suggesting that stress shadow would create an anisotropic environment for the surrounding rocks, which may affect the growth of hydraulic fractures.

Figure 4.14. Analytical results of dimensionless stress variation versus distance for a simple 2D crack. Stress is normalized by internal pressure, and distance is normalized by half height of the crack. The purple dots on horizontal axis represent relative location of next fracture in distance 220 ft (67m), 440 ft (134m), and 660 ft (200m) in terms of fracture height of 250 ft (76m).

In a developed shale reservoir with pre-existing natural fractures the fracture network is more complex. To explore the influence of stress shadow on hydraulic fracture geometry, an unconventional fracture model (UFM) is developed to create hydraulic fractures. This model is more suitable for shale gas reservoirs than the single planar model. It is because the model simulates not only hydraulic fracture propagation, but also interaction of pre-existing natural fractures and hydraulically induced fractures (Kresse et al. 2011; Weng et al. 2011). In our model, a discrete fracture network is created relying on the observation of natural fractures identified along the horizontal well. The azimuth of S_{Hmax} is selected based on the induced fractures observed in the vertical well, and the value 65° is used in the model. As the vertical constrain is not the key emphasis in this study, we limit the height of fracture to 250 ft (76m) determined from observation of vertical distribution of microseismic events. Types of fluid, proppant, and pumping schedule follow the treatment report summary for every stage. Dominant azimuth of natural fractures is used to create discrete fracture network. Due to low stress anisotropy in the study area, we treated reservoir as isotropic stress media. Result of simulated hydraulic fractures for stage 20 is shown in Figure 4.15. In the condition without stress shadow effect from prior stage, fractures grow symmetrically (Figure 4.15a). Simulated hydraulic fractures are not parallel planes, because the UFM calculates stress shadow for each fracture for stage 20. When introducing the stress shadow effect from the prior stage 19, the stress shadow makes hydraulic fractures of stage 20 divert and pull the fractures away from the already generated hydraulic fractures in stage 19 (Figure 4.15b, 4.15c). Figure 4.15b shows

hydraulic fracture simulation for stage 20, but these fractures are just small sample of the fractures observed in stage 20, and combination with stage 19 should be taken into consideration (Figure 4.15c). Hydraulic fractures will follow fracture paths of existing fractures when hydraulic fractures in current stage intersect with the fractures in prior stage (Kresse et al., 2012). Comparing simulated results with microseismic events, hydraulic fractures on the right side of the well (Figure 4.15c) nearly match the microseismic distribution. For the left side of the well, less microseismic events were created than observed during the hydraulic fracturing process. One possible reason is that rock between the two horizontal wells (right side of MIP3H) is more sensitive to hydraulic fracturing due to influence of stress perturbation of adjacent horizontal well MIP5H. In addition, other factors may exist to affect hydraulic fracture geometry. However, these factors are beyond the scope of this analysis.

Therefore, the concept of stress shadowing could offer an explanation of the deviated cluster of microseismic events observed in the MIP3H. Stress shadow from prior stage significantly diverts the direction of hydraulic fracture growth within the current stage. This phenomenon may play a role in the observed variation of production measured stage by stage during production logging (Figure 4.16). For an example, stage 20 has a relative low production rate, while stage 22 has highest production rate among all stages in the MIP3H. Observing adjacent stages, we found that stage 22 and corresponding area have more microseismic events that appeared to overlap into adjacent stages (Figure 4.17). To examine the microseismic event density, we built a 60 by 60 ft cell grid for stages 20 to 23 (Figure 4.18). For stages 20 and 21, the area of highest microseismic event density is not located adjacent to the well. For stage 20, the area of highest density is located to the southeast of the middle perf of stage 21, and this area is closer to stage 22. Similar to the stage 20, the area of highest microseismic event density of stage 21 is diverted, and located to the southeast part of the active stage. In the stage 22, events distribute evenly in a plane, and there is no apparent area with very high density. In the stage 23, event density is relatively higher on the right side of well, but there is also no obvious deviation in azimuth during this stage. Based on the observation of the distribution of microseismic events and event density, we found that more microseismic events appeared in the range of stage 22 indicating increased occurrence of microseismicity in the area of stage 22. These observations suggest that rock around stage 22 was fractured sufficiently, creating enhanced conditions for shale gas production. The increased occurrence of microseismicity comes from the prior stage 20 and 21, which may be a result of stress shadow. For stage 20 and 21 themselves, production rate is relative low because hydraulic fracturing may not be extensive enough in the surrounding rocks to support long-term production at high rates.

(a)

(b)

(c)

Figure 4.15. Hydraulic fractures generated using an UFM for stage 20 compared with microseismic events. (a) Simulated hydraulic fractures for stage 20 in the condition without stress shadow influence. (b) Simulated hydraulic fractures for stage 20 in the condition of stress shadow from the prior stage. (c) Combination of hydraulic fractures in stage 19 and 20 in the situation of stress shadow effects.

Figure 4.16. Gas production measured by the flow scanner production log for each stage.

Figure 4.17. Map view of microseismic events from stage 20 (green), 21 (red), 22 (purple), and 23 (yellow) of the MIP3H.

Figure 4.18. Microseismic event density computed for stages 20, 21, 22, and 23 in the MIP3H. Perforation clusters of stage 22 are shown with event density grid as a reference.

4.6 Discussion

When talking about stress shadow, every stage has a stress influence from the prior stage. However, it seems there is no apparent influence on microseismic distribution on stage 22. Microseismic events are distributed evenly and just around the perforations of stage 22. One possible reason is that treatment of stage 22 is different with other stages, because the stage was pumped twice (Figure 4.8). Induced S_{hmin} from the prior stage is a kind of compressive stress, thus growth of hydraulic fractures in the current stage are limited. The growth of hydraulic fractures have to compete with the extra compressive stress to let the fracture open. In the first pumping of stage 22, this part of pressure may play a major role on balancing the induced stress. In addition, the time difference between first and second pumping is about 4.7

hours. In this long-time duration, the induced stress in the rock may disappear gradually because stress in the formation tends to exist in the status of balance. These two conditions make the second pumping in the situation of less stress shadow effect from prior stage. Therefore, distribution of microseismic events is symmetrical around the well. Another possible reason is there is no large variation in azimuth of natural fracture around the stage 22. Based on the observation of natural fractures in the range of stage 22, dominant azimuth falls between 61° to 70° , and they are more uniform (Figure 4.11). In addition, the range of dominant azimuth of natural fractures is same as that of S_{Hmax} . Although natural fractures are distributed randomly in the space, hydraulic fractures do not divert significantly from the direction of S_{Hmax} .

4.7 Summary

In this study, microseismic events for every stage along the horizontal well MIP3H are examined by statistical methods using the b-value and D-value. Computed results show that both values vary stage by stage. Combining these two values, we found that the results can be divided into the three conditions. The first condition has both relative lower b-value and D-value, indicating activation of large events such as activation of faults. The second condition has relative lower b-value and higher D-value, suggesting natural fractures have larger influence on microseismic spatial distribution except of activation of faults. Both b-value and D-value are relative high for the third condition, suggesting natural fractures are primary influence factor. The three conditions can be used to interpret the activation of faults and natural fractures during the hydraulic fracturing. By employing hydraulic diffusivity to explore hydraulic conductivity, we found that reactivation of natural fractures or faults can be easily separated from hydraulic fractures of the matrix. Presence of faults or natural fractures usually results in higher value of hydraulic diffusivity. Based on the study of stage 22, the diffusivity of the second pumping does not follow the diffusivity of first pumping. It suggests that area of hydraulic fracturing was extended beyond the area of first pumping, and it may benefit production.

To explore the variation of dominant microseismic azimuth, natural fractures and stress shadow have influence on distribution of microseismic events. Azimuth of natural fractures from the study ranges at a low angle around the azimuth of S_{Hmax} . In this situation, hydraulic fractures are easily captured by these natural fractures. Through studying of Mohr's circle, these fractures are easily activated in the process of hydraulic fracturing. Activation of natural fractures affects the growth of hydraulic fracturing. In addition, stress shadow from the prior stage has a strong effect on the next stage. The stress shadow causes hydraulic fractures to divert away from the original pumping direction. Applied stress shadow in the UFM was compared with microseismic distribution, which shows that stress shadow has an influence on hydraulic fracture growth. As these diverted fractures appeared in the location of next stage, they may be activated and connected with hydraulic fractures created in the next stage. The deviation of hydraulic fractures may contribute to production in the adjacent stage. However, for the current stage, fracturing is not enough to create additional fractures, which may result in the lower production in this stage.

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APPENDICES

Appendix 1. Methods of Computing TOC from Well Logs

A1.1. Schmoker Method

Schmoker method is an empirical approach and give the relationship between bulk density and TOC (Schmoker, 1979; Schmoker, 1980), shown as below:

$$w_{TOC} = \left(\frac{154.497}{\rho_b} \right) - 57.261,$$

where ρ_b is bulk density (g/cm^3).

A1.2. $\Delta \log R$ Method

The method combines resistivity and density to predict TOC. Passey method (1990) modified by Charsky et al. (2003) shown as below:

$$\Delta \log R = \log \left(\frac{R}{R_{baseline}} \right) - \text{ScalingFactor}(\rho_b - \rho_{baseline}),$$

$$\text{ScalingFactor} = \frac{N}{\rho_{b_upper} - \rho_{b_lower}}, \text{ and}$$

$$w_{TOC} = \Delta \log R \times 10^{(2.297 - 0.168 \Delta \log R)},$$

where N is the number of resistivity divisions; LOM is the level of organic maturity.

Appendix 2. Methods of Computing Brittleness Index

A2.1. Mineral Brittleness Index

Rock brittleness index is dependent on the components of the rocks. Jarvie et al. (2007) reported that a high amount of quartz is an indication of brittleness compared to the total amount of quartz, carbonate and clay in sedimentary facies of the Barnett Shale.

$$BI = \frac{w_Q}{w_Q + w_{CM} + w_{Cl}},$$

where w_Q is the weight of quartz; w_{CM} is the weight of carbonate; and w_{Cl} is the weight of clay.

Wang and Gale (2009) described the brittleness index as a function of mineral composition and diagenesis. Compared to Jarvie's brittleness index, five components are taken into consideration as shown in the following equation:

$$BI = \frac{w_Q + w_D}{w_Q + w_D + w_C + w_{Cl} + w_{TOC}},$$

where BI is the brittleness index; w_Q , w_D , w_C , w_{Cl} and w_{TOC} are the weights of quartz, dolomite, calcite, clay and total organic carbon (TOC) respectively.

A2.2. Elastic Brittleness Index

In rock mechanics, Young's Modulus is the ratio of the stress and the strain, which measures the stiffness of a solid material. Another elastic parameter that measures lateral expansion relative to longitudinal contraction is known as Poisson's ratio.

With the advanced dipole sonic well logs, dynamic Young's modulus and Poisson's ratio can be calculated using the shear slowness and compressional slowness. The equations are shown below:

$$E_d = \rho \frac{4 - 3\Delta t_s^2 / \Delta t_p^2}{\Delta t_s^2 (1 - \Delta t_s^2 / \Delta t_p^2)},$$

$$\nu_d = \frac{2 - \Delta t_s^2 / \Delta t_p^2}{2(1 - \Delta t_s^2 / \Delta t_p^2)},$$

where E_d is the dynamic Young's modulus; ν is the dynamic Poisson's ration; ρ is the bulk density (g/cm^3); Δt_s is the shear slowness ($\mu\text{s/ft}$); and Δt_p is the compressional slowness ($\mu\text{s/ft}$).

Normalized dynamic Young's modulus and Poisson's ratio are given by following equations:

$$E_n = \frac{E - E_{\min}}{E_{\max} - E_{\min}},$$

$$\nu_n = \frac{\nu_{\max} - \nu}{\nu_{\max} - \nu_{\min}},$$

where $E_{\max}$ and $E_{\min}$ are the maximum and minimum dynamic Young's modulus; $\nu_{\max}$ and $\nu_{\min}$ are the maximum and minimum dynamic Poisson's ratio.

The brittleness index (BI) can be expressed as the average weighted dynamic Young's modulus and Poisson's ratio (Grieser et al., 2007; Richman et al., 2008):

$$BI = \frac{E_n + \nu_n}{2}.$$