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Geomechanics in Unconventionals

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Wednesday AM	Session 1	- Geomechanical Characterization
Wednesday PM	Session 2	- Engineering Applications
Thursday AM	Session 3	- Surveillance and Diagnostics
Thursday PM	Session 4	- Case Studies

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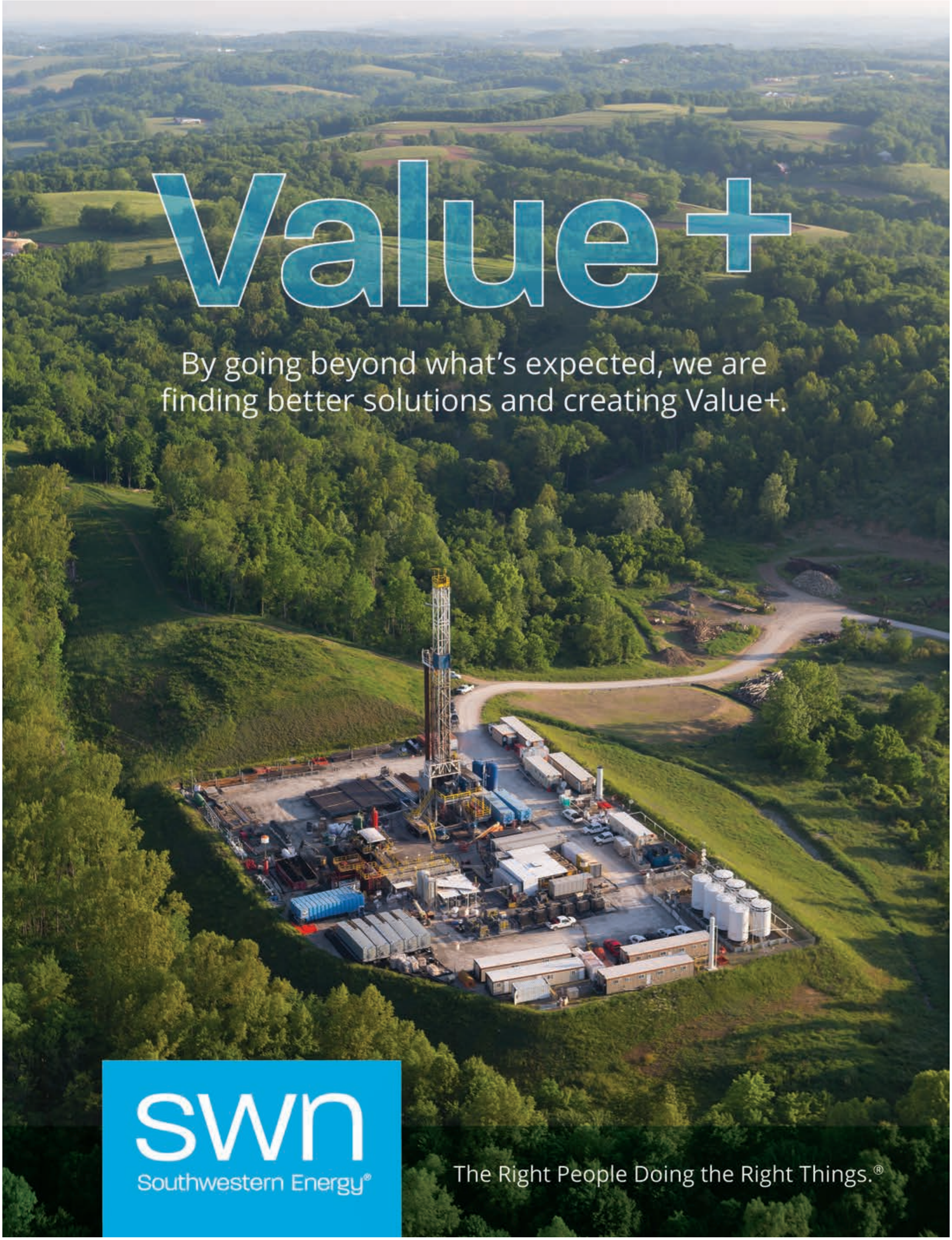
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November 8-9, 2017

Geomechanics in Unconventionals

November 8-9, 2017
Southwestern Energy · Spring, Texas

Proceedings Volume

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A LINE HAS BEEN DRAWN.
BETWEEN THE SAME WAY AND A NEW WAY.
BETWEEN ENERGY DEMAND AND ENERGY POTENTIAL.
BETWEEN MAINSTREAM AND FULLSTREAM.
BETWEEN THE INDUSTRIAL AND THE DIGITAL INDUSTRIAL.
BETWEEN SETTLING FOR TODAY AND DEFINING TOMORROW.
TODAY, A LINE HAS BEEN DRAWN.
AND THE PAST IS ON ONE SIDE AND WE'RE ON THE OTHER.
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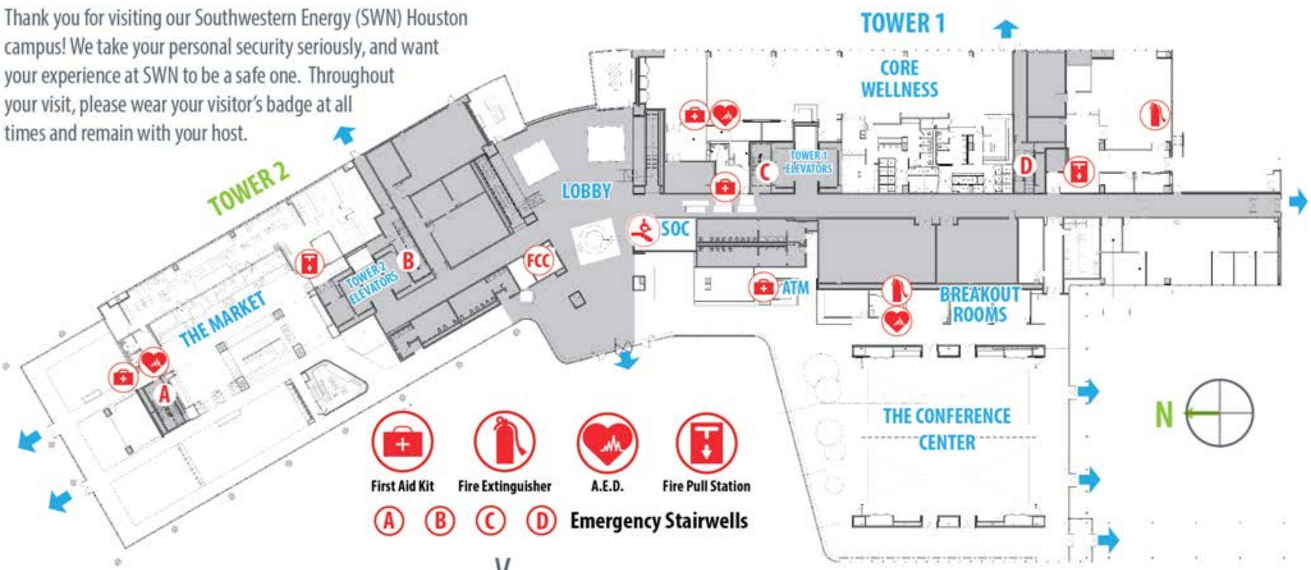

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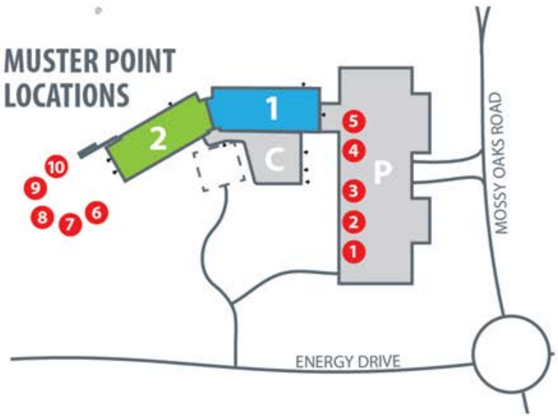

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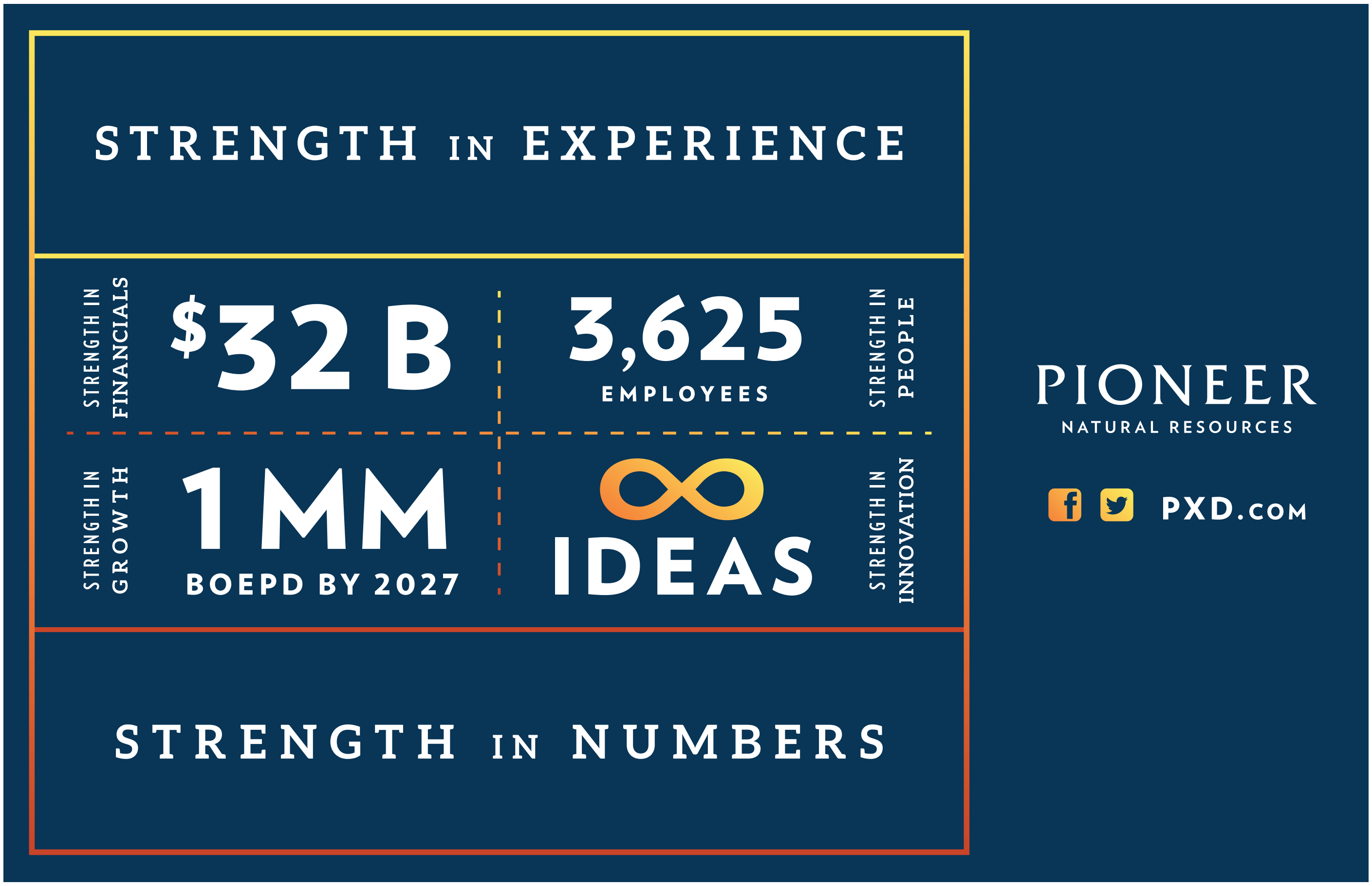
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Applied Geoscience Conference

November 8–9, 2017

Oral Presentations – Wednesday, November 8, 2017

7:00	**Registration and Coffee**	
8:00 - 8:10	**Welcome and Opening Remarks:** Robert Hurt, *Pioneer Natural Resources;* Umesh Prasad, *Baker Hughes, a GE company*; John Adamick, *TGS, HGS President 2017-2018;* Ron Hayden, *SWN Vice President of Technology*	
	Session 1: Geomechanical Characterization **Chairs:** Shihong Chi, *ION E&P Advisors* ; Farid Reza Mohamed, *Schlumberger*	
8:10 - 8:45	A Novel Geomechanical Characterization Methodology for Quantifying Fine Scale Heterogeneity	**Jesse Hampton**, *New England Research*
8:45 - 9:20	Brittleness and Fracability in Stimulating Shale Reservoirs	**Mao Bai**, *Independent Geomechanics Consultant*
9:20 - 9:40	**Coffee, Posters, Exhibits**	
9:40 - 10:15	The Relationship between Natural Fracture Distribution and Elastic Mechanical Properties in the Subsurface: Measurement and Calibration	**Ron Nelson**, *Broken N Consulting, Inc.*
10:15 - 10:50	A Novel Method for Experimental Determination of Biot's Coefficient in Unconventional Formations.	**Munir Aldin**, *MetaRock Laboratories*
10:55 - 11:55	**Open Floor Discussion & Posters**	
11:55 - 1:00	**Lunch, Posters, Exhibits**	
12:15 - 1:00	**Keynote:** What Maintains High Pore Pressure in Gas Shale During Exhumation, Long After Thermal Maturation Ceases?	**Terry Engelder**, *The Pennsylvania State University*
	Session 2: Engineering Applications **Chairs:** See Hong Ong, *Baker Hughes, a GE company*; Cem Ozan, *BHP Petroleum*	
1:05 - 1:40	Complex Fracture Network Creation in Stimulation of Uncoventional Reservoirs	**Ahmad Ghassemi**, *The University of Oklahoma*
1:40 - 2:15	Hydraulic Stimulation in the Presence of Fractures	**Tobias Hoeink**, *Baker Hughes, a GE company*
2:15 - 2:35	**Coffee, Posters, Exhibits**	
2:35 - 3:10	A Holistic Approach to Geologic and Geomechanical Modeling in Unconventional Reservoirs PART 1	**Ewerton Araujo, Sebastian Bayer, Marcus Wunderle,** *BHP Petroleum*
3:10 - 3:45	A Holistic Approach to Geologic and Geomechanical Modeling in Unconventional Reservoirs PART 2	**Ewerton Araujo, Sebastian Bayer, Marcus Wunderle,** *BHP Petroleum*
3:45 - 4:45	**Open Floor Discussion & Posters**	
5:00 - 8:00	**Social Hour**	

Applied Geoscience Conference

November 8–9, 2017

Oral Presentations – Thursday, November 9, 2017

7:00	**Registration and Coffee**	
8:00 - 8:10	**Welcome and Opening Remarks:** Robert Hurt, *Pioneer Natural Resources;* Umesh Prasad, *Baker Hughes, a GE company*; John Adamick, *TGS, HGS President 2017-2018*	
	Session 3: Surveillance and Diagnostics **Chairs:** Robert Hurt, *Pioneer Natural Resources;* Kim Hlava, *Statoil*	
8:10 - 8:45	Validating Completion Design Using Monitoring of Offset Wells	**Erica Coenen,** *Reveal Technologies*
8:45 - 9:20	DAS Microseismic Monitoring and Integration with Strain Measurements in Hydraulic Fracture Profiling	**Dan Kahn,** *Devon Energy*
9:20 - 9:40	**Coffee, Posters, Exhibits**	
9:40 - 10:15	Focal Mechanism Solutions of Microseismic Events from Hydraulic Fracture Monitoring: A Case Study of the Eagle Ford Shale	**Rongmao Zhou**, *BHP Petroleum*
10:15 - 10:50	Integration of DAS Fiber-Based Strain and Microseismic Data for Monitoring Horizontal Hydraulic Stimulations – Midland Basin Texas Examples	**Rob Hull**, *Pioneer Natural Resources*
10:55 - 11:55	**Open Floor Discussion & Posters**	
11:55 - 1:00	**Lunch, Posters, Exhibits**	
12:15 - 1:00	**Keynote:** Optimized Recovery from Unconventional Reservoirs: How Nanophysics, the Micro-Crack Debate, and Complex Fracture Geometry Impact Operations	**Lans Taylor**, *Energy and Geoscience Institute (EGI) at the University of Utah*
	Session 4: Case Studies **Chairs:** Joel Walls, *Ingrain, a Halliburton service;* BJ Davis, *Baker Hughes a GE company*	
1:05 - 1:40	Quantifying the Impact of Induced Asymmetric Fracturing from Horizontal Development Wellbores; a Geostatistical Perspective	**Doug Walser**, *Halliburton*
1:40 - 2:15	Efficient Well Delivery in Shale Plays – Examples from the Marcellus and Permian	**Julie Kowan,** *J. Kowan Consulting, LLC*
2:15 - 2:35	**Coffee, Posters, Exhibits**	
2:35 - 3:10	Characterization of Fractures from Borehole Images	**Sandeep Mukherjee,** *Halliburton*
3:10 - 3:45	Lateral Characterization and Fracture Optimization Solution with Case Studies	**Sergey Kotov,** *Baker Hughes, a GE company*
3:45 - 4:45	**Open Floor Discussion & Posters**	
	Closing Comments and Invitation to Posters	

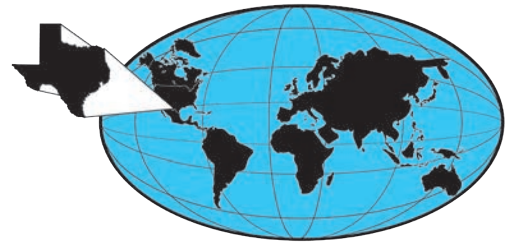
Poster Session

Invited Presentations from Graduate Students • Open during Coffee and Lunch Breaks

Posters – November 8-9, 2017

Poster Session Chair: Mike Effler

University	Student Name	Poster Topic
Georgia Institute of Technology	**Ming Lui** and Haiying Huang	A Poroelastic Solution of Rigid Sphere Indentation into a Compressible Half-Space
Texas A&M University	**Anusarn Sangnimnuan** and Jiawei Li, Kan Wu	Development of an Efficient Coupled Fluid Flow and Geomechanics Model to Predict Stress Evolution in Unconventional Reservoirs with Complex Fracture Geometry
Texas A&M University	**Arash Shadravan** and Behrouz Haghgouyan	Geomechancal Cement Sheath Finite Element Modeling to Achieve Enhanced Zonal Isolation
Texas A&M University	**Edith Sotelo Gamboa** and Richard L. Gibson	Fracture Compliance: Relationship with Fracture Conductivity and effect on Wave Propagation
Texas A&M University	**Guangjian Xu**, Judith Chester and Fred Chester	Developing a Mechanical Stratigraphic Model of the Eagle Ford Formation
The University of Oklahoma	**Ishank Gupta**, Carl Sondergeld and Chandra Rai	Water Weakening: Case Study from Marcellus, Woodford and Eagle Ford
The University of Oklahoma	**Alex Vachaparampil** and Ahmad Ghassemi	Failure Characteristics of Three Shales under True-Triaxial Compression
The University of Oklahoma	**Zhi Ye** and Ahmad Ghassemi	Mechanical Properties and Permeability Evolution of Shale Fractures under Triaxial Loading
The University of Texas	**Matthew Ramos**, D.N. Espinoza, C.I. Torres-Verdín, K.T. Spikes and S.E. Laubach	Stress-Dependent Dynamic-Static Transforms of Anisotropic Mancos Shale
University of Calgary	**Bram Komaromi**, Dr. Per Kent Pedersen and Dr. Paul MacKay	Facies-Controlled Fracture Stratigraphy in Organic-Rich Petroleum Systems, Turonian Second White Specks Formation, Southwestern Alberta
University of Houston	**Ismot Jahan**, John Castagna, and Michael Murphy	Characterization of Faults Using Seismic Attributes From 3D Seismic Data in the Bakken Formation
University of Houston	**Ali Rezaei**	Effect of Pore Pressure Depletion on Horizontal Stresses and Propagation of New Fractures during Refracturing Process



Abstracts

Oral Presentations
Day One

November 8, 2017

Southwestern Energy
Spring, Texas

Wednesday, November 8, 2017 | Session 1 | 8:10
Jesse Hampton, G. Boitnott, L. Louis
New England Research
White River Junction, Vermont

A Novel Geomechanical Characterization Methodology for Quantifying Fine Scale Heterogeneity

Summary

The integration of plug and log scale characterization is key to generating representative engineering inputs for geomechanical models in oil and gas exploration and development. The importance of plug measurements is especially vital in finely laminated rocks where well-log scale measurements miss mechanical heterogeneities that are required for realistic mechanical models. The presence of mechanical heterogeneity and anisotropy under the well log resolution is commonplace in unconventional plays and can deeply impact geomechanical assessments ranging from wellbore integrity to horizontal stress estimates.

The first part of the presentation will focus on a few laboratory-based inputs that are increasingly being recognized as high impact. We will address the topics of continuous mechanical profiling, and anisotropy quantification for both poroelastic constants including the extraction of an anisotropic stiffness tensor and Biot coefficients.

In a second part, we will address the optimization aspect. To that effect, we will suggest ways to greatly increase workflow relevance and efficiency by relying on the use of petrophysical core scanning for screening, rock typing, and plug picking. New closed loop workflows allow for upscaling lab observations to the log scale at different stages of the process, thus providing an early option for decision making.

Continuous Mechanical Profiling

NER's Core AutoScan is a unique measurement platform developed for the detailed quantitative and efficient description of core properties. It is capable of scanning at the millimeter scale slabbed whole core or plugs for gas permeability, resistivity, ultrasonic compressional- and shear-wave velocities, composition, mechanical strength, and elastic stiffness (Impulse Hammer). The Impulse Hammer was originally developed to provide a non-destructive method to measure the mechanical profile along a core. The Impulse Hammer captures the physics of the impact by measuring the force-time function as the indenter is free falling onto the sample surface, and thus two independent parameters can be extracted, reduced Young's modulus and an impulse hardness. An example of fine scale heterogeneity observed in a Wolfcamp core can be seen in **Figure 1.**

Mechanical and Poroelastic Anisotropy

It is possible to measure 4 of the 5 independent static moduli for a single plug with the plug axis parallel to bedding. The static elastic moduli are measured by fitting the stress versus strain response to a sequence of loading cycles. Using this method we measure all the static moduli except C44=1/S44=G. The static test can be continued with a sequence of confining and pore pressure cycles after the introduction of pore fluid to constrain a poroelastic model including the anisotropic Biot parameters αv and αh.

The horizontal samples can then be conditioned and tested for anisotropic dynamic moduli using both axial and radial compression- and polarized shear-wave ultrasonic velocity transducers. A three-axis velocity test can be performed to measure the five independent stiffnesses (including C13), and thus compute all of the VTI elastic constants.

From a single horizontal plug, dynamic/static and poroelastic VTI properties are measured which greatly reduces the uncertainty in multiple measurements using plugs that could sample several bedding layers, if vertical or 45° can be obtained at all. This process of using horizontal plugs lends itself well to the use of rotary sidewalls as well.

Optimization and Upscaling

There arises two large core to log integration problems when fine scale heterogeneity data is not available or used, (1) plugs typically chosen based on well-log scale information in unconventionals are often consisting of several rock types (mechanical, compositional, petrophysical) which makes individual plug interpretation cumbersome at best and impossible at worst, and (2) if one is able to interpret plug data coming from a sample consisting of several rock types, how is this data then integrated back into the log scale? To this end, the mm scale measurements made with the AutoScan apparatus can provide enough information for rock typing using composition, mechanical, or petrophysical properties at several scales, and thus provide detailed estimations of where

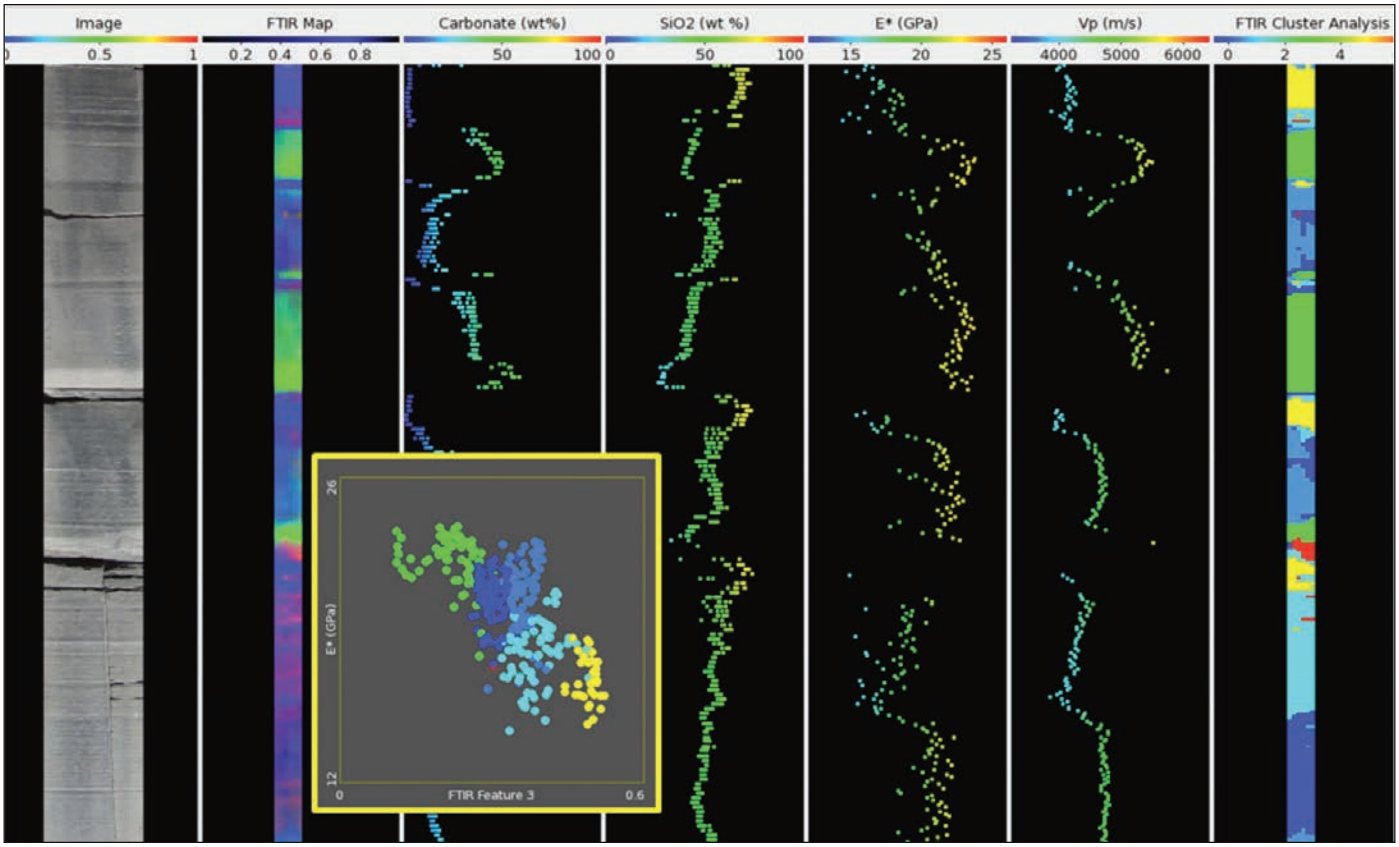


Figure 1. *Small section (three feet) of the large Wolfcamp dataset showing fine scale heterogeneity information and comparison between mechanical properties and composition, separated by mudstone type.*

plugs are required, and where traditional plugging plans may provide redundant or no information on several rock types. The optimized plug sample scheme typically requires fewer total samples, and provides a more intuitive interaction between the plug and log scale.

Upscaling workflows using these datasets can generally take three paths depending on what data is available (1) plug information applied directly to logs, (2) plugs plus AutoScan upscaling using core only, and (3) core calibrated upscaled transforms, from (2), applied to logs. The full presentation will discuss these aspects in more detail and compare/contrast the results of each using the Wolfcamp shale as an example. **Figure 1** shows some of the Wolfcamp dataset consisting of fine scale heterogeneity information from the AutoScan, as well as the rock types determined at the log and sub-log resolution (far right column).

Biographical Sketch

Jesse Hampton joined New England Research, Inc. as a Principal Scientist in 2015. His specialties include experimental rock mechanics and non-destructive evaluation (NDE) for the purpose of reservoir rock and fracture characterization. He has previously been involved with development of several NDE analysis techniques and equipment design aimed at scale model testing of microfracture generation and coalescence. Jesse has also developed multiple patents related to material characterization, both downhole and in the laboratory, as well as downhole fracture generation methods for enhanced hydrocarbon recovery. He presently helps NER in the development and anal¬ysis of geomechanics and petrophysics testing programs to aid in reservoir rock characterization and model generation. His current research involves the development of methodologies suited for contact measurements to determine elastic and inelastic rock properties and strength. He holds a PhD from Colorado School of Mines in Civil Engineering.

Mao Bai
Geomechanics Consultant

Brittleness and Fracability in Stimulating Shale Gas Reservoirs

Summary

In the present study of stimulating unconventional shale reservoirs, brittleness index profiling along the reservoir payzone to identify the most desirable perforated intervals has become a common practice. The profile is considered as an indispensable geomechanics component in the approaches in the petrophysical domain. However, this paper challenges the validity of the brittleness index profiling method. With objective review and sensible definition of brittleness used in the present petrophysical field to identify the desirable fracturing intervals, the paper presents the ambiguities of using brittleness to define the formation fracability, and points out that the formation brittleness can be unrelated to the formation fracability. As an alternative approach, this paper provides an effective method to define the most fracable formation intervals in designing the hydraulic fracturing in tight shale gas formations.

Content

With respect to brittleness, it is about the type of material and its related strength. In comparison with a ductile material under load, a brittle material has a relatively shorter plastic deformation and responds dominantly by the elastic deformation. With respect to fracability, it is about the rock failure under the ultimate rock strength in either a brittle or ductile formation. In comparison, the higher fracable formation should have smaller formation strength than the lower fracable formation. In consequence, it is not certain that the brittle formation is easier to fracture than the ductile formation since a brittle formation may have greater strength than a ductile formation even though the exceptions may exist.

More complications arise when evaluating the responses of subsurface formations at great depth than the formation types (e.g. brittle formation or ductile formation). Under this condition, the impact of confinement on the fracability cannot be ignored. In general, a formation subject to higher confinement pressure is more difficult to fracture as the formation strength is greater. Conversely, a formation subject to lower confinement pressure is easier to fracture since the formation strength is smaller.

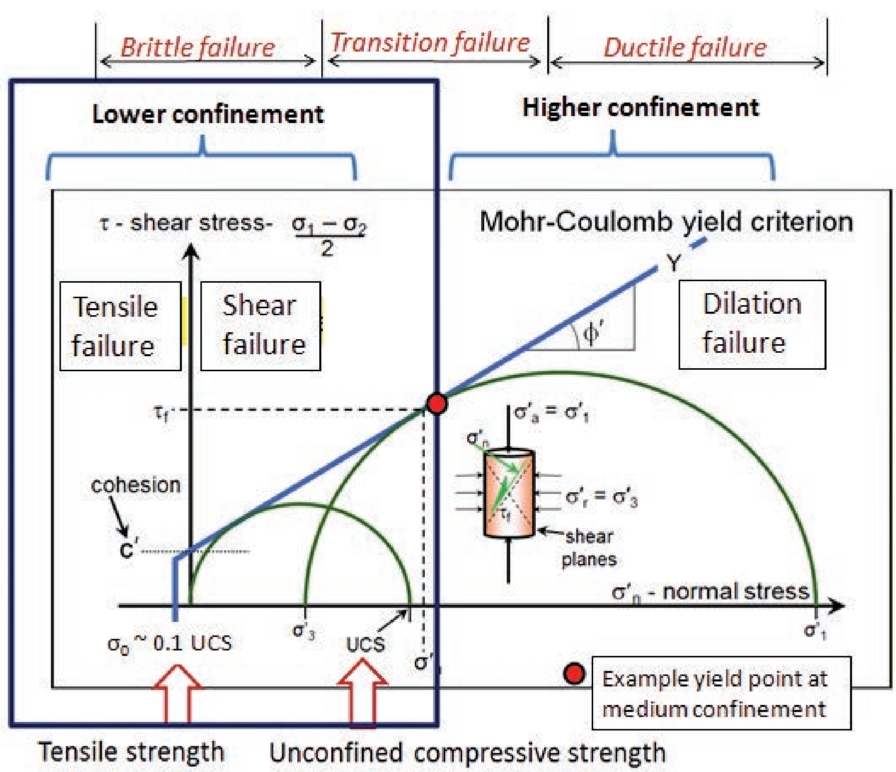


Figure 1 *Example yield point is the cutoff value in the transition failure between brittle (lower confinement) and ductile (higher confinement) rock failures in a Mohr-Coulomb chart.*

In view of efficient stimulation of shale gas reservoirs, it is unclear whether we should choose the brittle interval or the ductile interval to fracture as the strength of either interval is unknown. However, it is apparent that we should choose the formation interval with a higher fracability, which is equivalent to the lower formation strength. Under similar confinements, the lower formation strength may be indicated by a smaller unconfined compressive strength (UCS). As a result, it is advisable that the most fracable interval is the one with lowest UCS.

When evaluating present technology, the formation brittleness should no longer be the associated subject matter as we are unclear about its role to improve the fracability of a tight formation. Disassociating the brittleness from fracability enables us to focus on identifying the true mechanisms for efficient fracturing of tight shale reservoirs.

Conclusions

Formation brittleness and ductility are not related to formation mechanical properties such as Young's modulus and Poisson's ratio, as commonly used in brittleness index profiling. Instead, formation brittleness and ductility are related to the rock strength such as unconfined compressive strength (UCS) or fracture toughness.

It is ambiguous to relate formation brittleness to formation fracability, since a brittle formation may have greater rock strength under higher confinement, making it more difficult to fracture, and vice versa.

The formation fracability is about the ultimate rock failure defined by the formation breakdown pressure. The breakdown pressure can be identified in unrestricted fracturing using the unconfined compressive strength (UCS) as a benchmark value. However, it is difficult or sometimes impossible to identify the breakdown pressure in restricted fracturing since the fracturing treatment is limited in size and is often localized, while the extended free fracture propagation is not apparent from the bottom hole pressure response. Under this condition, the formation fracability may be determined from the fracture toughness based dynamic fracturing process.

Disassociating formation brittleness from formation fracability allows us to correctly determine the most fracable formation intervals to perforate.

This presentation proposes an effective approach to select the desirable intervals to stimulate, i.e., select the weak spots determined from a formation UCS profile to establish the perforated intervals. The proposed method is supported by many early experimental studies. ■

References

Bai, M. (2016), Why are brittleness and fracability not equivalent in designing hydraulic fracturing in tight shale gas reservoirs, Petroleum, Vol. 2, 1-19, ISSN 2405-6561, SwPU, Elsevier.

Biographical Sketch

Mao Bai received the Ph.D. degree in mineral engineering in 1991 from Pennsylvania State University. Afterwards, he worked as a senior research associate at the Rock Mechanics Institute (University of Oklahoma) between 1991 and 2000; as a senior engineer at TerraTek (a Schlumberger company) between 2000 and 2007; as a senior geomechanics specialist at Geomechanics International (a Baker Hughes company) between 2007 and 2008; as a principal consultant/senior advisor at global consulting division of Halliburton between 2008 and 2013; and as a staff geomechanics specialist at BHP Billiton between 2013 and 2015. He is currently a geomechanics consultant.

Wednesday, November 8, 2017 | Session 1 | 9:40
Ron A. Nelson,
Broken N Consulting
Cat Spring, Texas

The Relationship Between Natural Fracture Distribution and Elastic Mechanical Properties in the Subsurface: Measurement and Calibration

Natural and completion-related fractures are very important in production of oil and gas reservoirs around the world. The development of both types of fractures is the result of applied forces and the mechanical properties of the reservoir rock materials as measured statically or dynamically, per **Figure 1.**

Material properties of the rocks such as Young's Modulus (E), Poisson's Ratio (γ), and a combined version called Rigidity or Shear Modulus (G), have been used to define the mechanical stratigraphy of the reservoir section, **Figure 2.**

Quantitative work on many reservoirs around the world has highlighted this relation with different classes of relations for different rock types. The presentation will show these relations and attempt to quantify the relationship and how it might vary with gross rock type and scale of observation.

In general, natural fracture intensity or fracture density increases with decreasing Poisson's Ratio and increasing Young's Modulus and, alternately, Rigidity Modulus at the time of fracturing, **Figure 3**.

Multiple periods of natural fracturing may have been related with varying mechanical properties due to diagenetic alteration of the reservoir occurring between fracturing periods. The same mechanical property control occurs for hydraulic fracture completions in low permeability reservoirs, especially for the initiation of hydraulic fractures, fracture propagation, as well as hydraulic fracture containment

This presentation will focus on how subsurface natural fracture distributions are properly quantified from core observations and analysis of interpreted Borehole Image Logs. In addition, these same sections are quantified mechanically using mechanical properties logs (eg. shear sonic logs). Lastly, the predictability of natural fracture distributions directly from mechanical properties logs will be discussed.

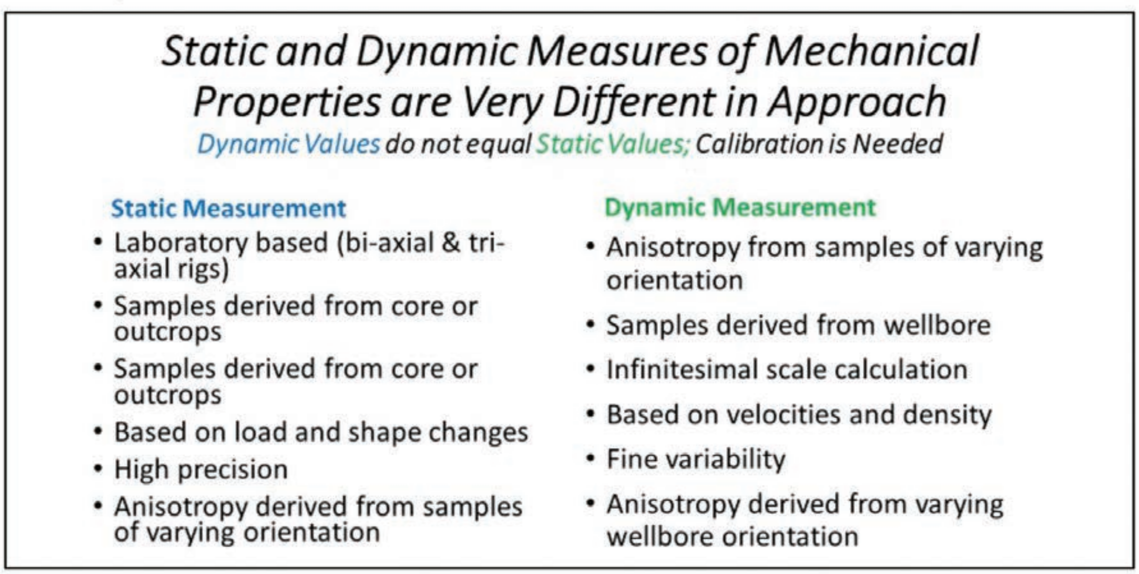


Figure 1. *Rock mechanic properties are measured in the laboratory (Static) or in the subsurface via shear logs (Dynamic). The two methods result in different values which are appropriately applied in different situations.*

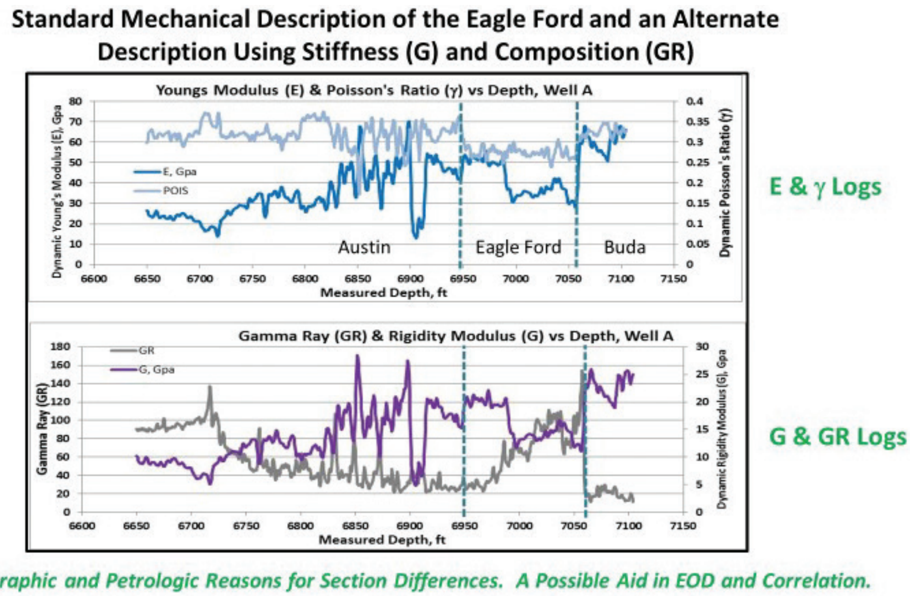


Figure 2. *Shown is an example of use of dynamically obtained mechanical data to define the mechanical stratigraphy of a reservoir section.*

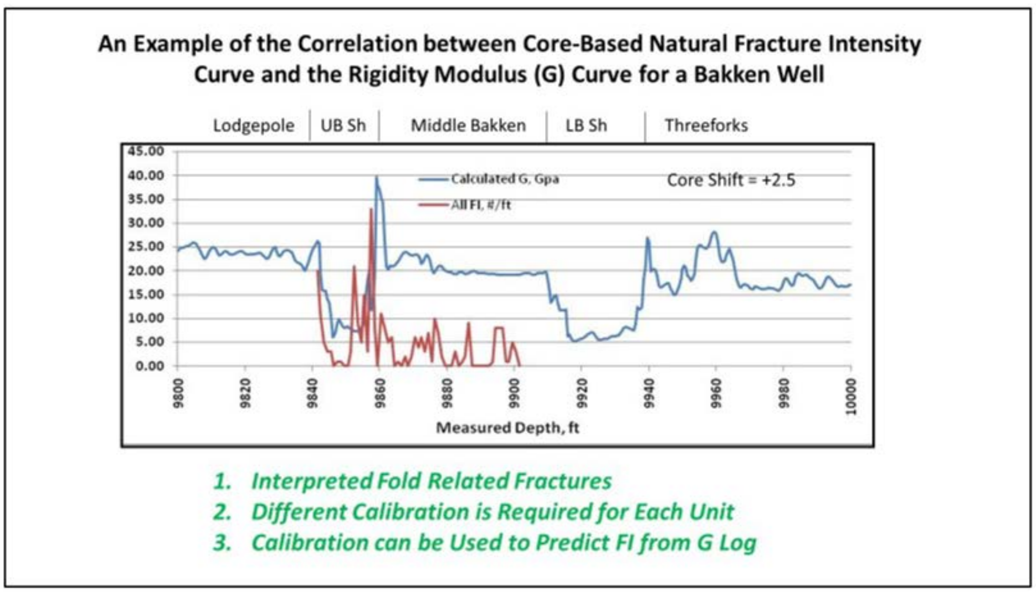
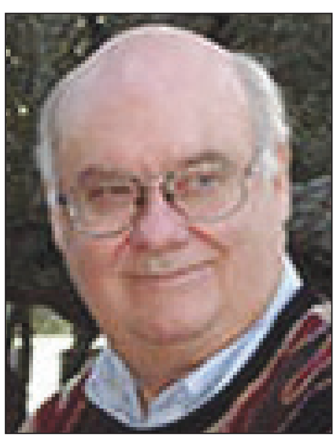


Figure 3. *Shown is an example of the relationship between core-based Natural Fracture Intensity (FI) and Rigidity Modulus (G) in a Bakken well. Relatively higher G equates to relatively higher FI.*

Biographical Sketch



Dr. Ronald A. Nelson has worked with fractured reservoirs for over 40 years with Amoco, BP Amoco and now Broken N Consulting, Inc. He has taught numerous courses on fractured reservoirs for the AAPG, SEG, and NExT, and has authored over 100 publications on the subject, including the 1985 and 2001 editions of his textbook entitled "Geologic Analysis of Naturally Fractured Reservoirs". He has lectured on the subjects of structural geology and fractured reservoirs to Geological Societies, Universities, and National Oil Companies in over 20 countries and has been an AAPG Distinguished Lecturer twice and an SPE Distinguished Author. He has served as President of the Houston Geological Society, Vice President of the AAPG and Councilor at large for the Tulsa Geological Society. He was awarded the AAPG Robert R. Berg Outstanding Research Award in 2013.

Munir Aldin, Deepak Gokaraju, Abhijit Mitra, Sudarshan Govindarajan, Samuel Aldin
MetaRock Laboratories

A Novel Method for Experimental Determination of Biot's coefficient in Unconventional Formations.

Abstract

Biot's coefficient (α) is one of the key parameters in determining the anisotropic minimal horizontal stress which is crucial to managing borehole stability, landing zones hydraulic fracturing design and reservoir compaction issues. In this study we propose a new time efficient method to characterize α by monitoring the P-wave first arrival time using a high precision device with a resolution of 1 nanosecond. This method only uses acoustic velocity as a gauge while directly quantifying the poro-elastic constant. This method was applied to multiple samples from different shales across North America. Mineralogical data is used to evaluate and analyze the poro-elastic behavior of a few shale samples.

Introduction

The efforts related to the unconventional reservoir studies have been increasing to determine the amount of hydrocarbon in place and develop techniques to produce it. Among the items of interest is the understanding of the field in-situ stresses which influence the well stability, landing zones and hydraulic fracturing design and managing reservoir compaction issues. Additionally, adds a significant contribution to field development and economic success.

Methods upon the utilization of sonic logs along with core data to determine anisotropic minimal horizontal stress are well published and found in the literature. Generally, the methods require the understating of mechanical properties and Poroelastic constant (BIOT). Due to the difficulties experienced to access the pore space in ultralow permeability formations (shale) to determine the grain modulus value, supercritical fluids was used while measuring compressional and shear ultrasonic velocity. Measurement confirms relationship between stress and ultrasonic velocity during pore pressure inflation and hydrostatic pressure deflation. This implies the real-time ultrasonic velocity measurement can be used a gauge to control the required amount of stress. The effective stress law essentially asserts that there are multiple combinations of pore pressure and confining pressure which yield equivalent effective stress states through a simple linear coefficient α.

The Biot's coefficient (α) is a poro-elastic coefficient that defines the relationship between rock matrix framework and fluids in a porous rock. The concept of effective stress was introduced by Terzaghi (1934, 1937) by observing the shearing resistance of saturated soils. Biot (1941) extended the effective stress principle by including the Biot's coefficient as shown below:

$$\sigma' = \sigma - \alpha P_P$$

σ' is the effective stress, σ is the total stress, α is the Biot's coefficient and PP is the pore pressure. Based on the concept of effective stress, multiple methods have been presented to measure or characterize Biot's coefficient. The first method involves calculating a Biot's coefficient by quantifying the grain and bulk compressibility (Cg and Cb respectively) or the grain and bulk modulus (Kg and Kb respectively) as shown below. Azeemuddin (2002) improved this technique by measuring K_b and K_g with "static" and "dynamics"' methods.

$$\alpha = 1 - \frac{C_g}{C_b} = 1 - \frac{K_b}{K_g}$$

Franquet and Abass proposed measuring Biot's coefficient by measuring the expelled fluid volume. α is the ratio of variation in pore volume (ΔV_p) and total rock volume (ΔV) with change in stress as shown below:

$$\alpha = \frac{\Delta V_P}{\Delta V}$$

He and Ling (2014) and Qiao (2012) proposed a method to estimate Biot's coefficient using changes in permeability with variation of stresses. Both methods assume that the permeability and strain follow the effective-stress law. According to the methods, Biot's coefficient is the ratio of the variation of the confining pressure to the variation of the pore pressure while maintaining constant strain (He and Ling) or studying the change in permeability (Qiao), which is

$$\alpha = \frac{\Delta\sigma}{\Delta P_P} = \frac{\Delta k_p}{\Delta k_c}$$

where Δkp is the change of permeability with the variation of the pore pressure while confining stress is kept constant, and Δkc is the change of permeability with the variation of the confining stress while pore pressure is maintained constant. In low permeability formations like shale's or tight sandstones, measuring variations in permeability or in pore volume using the above methods are difficult and time consuming. Usage of supercritical gas instead of fluid in tight formations will increase time efficiency while avoiding slippage (Klinkenberg) effect. However, permeability experiments with supercritical gas are prone to gas leakage.

Method

The proposed method involves using P-wave arrival time as a gauge to measure Biot's coefficient value instead of permeability as suggested by Qiao (2012). It is common to use ultrasonic velocity to calculate elastic properties such as Young's Modulus and Shear Modulus of Elasticity, and Poisson's ratio. The assumption involved in this method is that the change in P-wave velocity follows the effective stress law asserting that there are multiple combinations of pore pressure and confining pressure which yield equivalent effective stress states through a simple liner coefficient. While introducing a small pressure step change (~300psi) the change in P-wave velocity is small (200 ft/sec) requiring a high precision device for first arrival time (ITT_p) detection with a resolution of 1 nanosecond to monitor real time change in ultrasonic velocity. This method only uses acoustic velocity as a gauge while directly quantifying the poro-elastic constant. Since it is done real time, the confining stress is then increased until the ΔITT_p returns to 0. Biot's coefficient can then be quantified using:

$$\alpha = \frac{\Delta\sigma}{\Delta P_P}$$

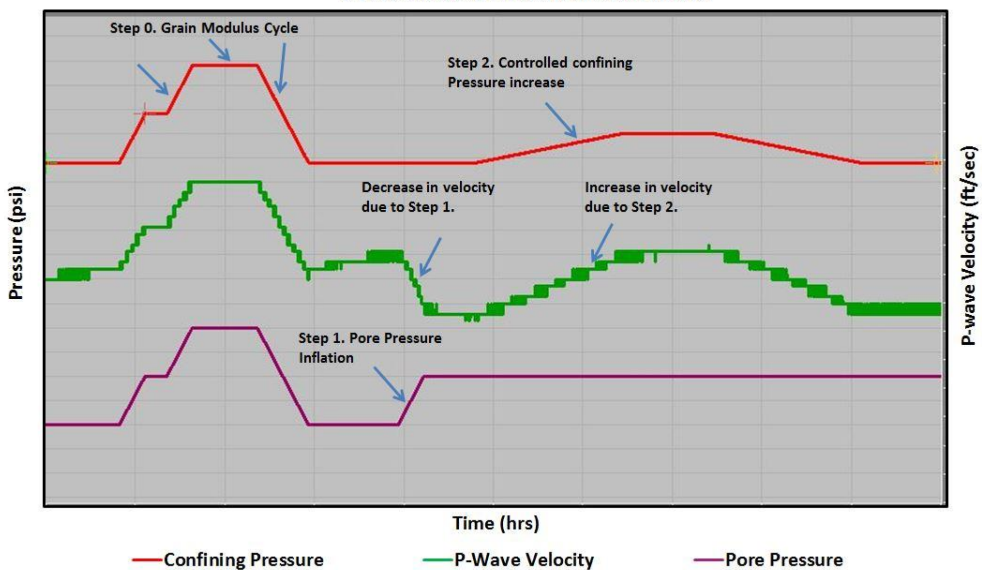


Figure 2. *Biot's Experiment*

The proposed method can increase accuracy in the experiment because of the significant difference in the resolution between permeability measurements and acoustic velocity measurements. The proposed method is also significantly quicker.

Figure 2 shows preliminary test results of an experiment conducted using the proposed method. **Figure 2** shows the increase in arrival time (Green curve) with increasing confining pressure during the first half of the experiment. The second half shows decrease in arrival time with increasing Pore pressure (red curve). The ratio of the confining pressure change during the first half of the experiment and the pore pressure change during second half of the experiment is the Biot's coefficient.

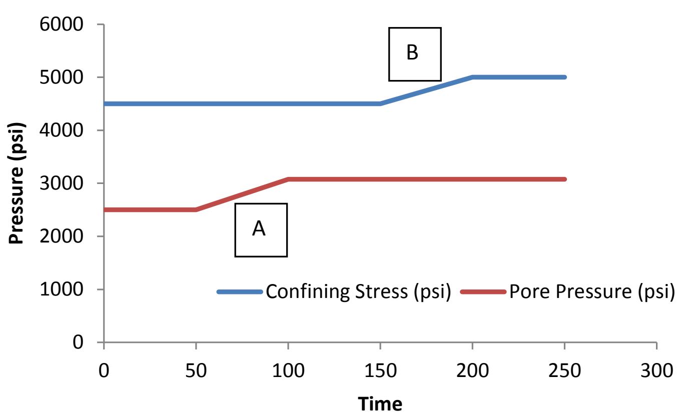


Figure 1. *A - Pore pressure increase. B - Confining pressure increase.*

The paper quantifies and compares Biot's coefficient for multiple samples. Mineralogical data is available for a select few samples which are analyzed and compared along with Biot's coefficient and other poro-elastic mechanical properties. ■

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Biographical Sketch

Munir Aldin, the founder of MetaRock Laboratories, has a Masters degree in Electrical Engineering and Computer Science. He has been involved in Rock Mechanics testing and consulting for over 20 years. Munir has been working closely with several Oil & Gas operators and research institutions/Universities in developing research grade testing equipment to better understand rock behavior under stress. This knowledge has helped MetaRock Laboratories' clients to develop techniques to devise strategies to maximize oil and gas recovery. In the past, Munir has extensively worked on anisotropy characterization, Stress Characterization studies, Compaction studies, Electrical properties, Ultra low Permeability, Porosity etc. He is currently working on developing the technology to perform experiments under HPHT conditions to help researchers better understand complex behavior in developing difficult hydrocarbons.

Notes

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What Maintains High Pore Pressure in Gas Shale During Exhumation, Long After Thermal Maturation Ceases?

The Ordovician Point Pleasant-Utica shale gas play is economic in large part because it is presently overpressured as is its counterpart the Devonian Marcellus gas shale of the Appalachian Basin (Zhou et al., 2017). Both gas shales maintain a gas reservoir at high pressure despite being exhumed and in some cases exhumation is more than 50% of their maximum depth of burial (Evans, 1995). Capillary pressure at the top and bottom boundaries of these gas shales is an effective seal for keeping gas in place and at well in excess of hydrostatic pressure for as much as 400 My as is the case for the Point Pleasant-Utica gas shale (Engelder et al., 2014). This is a bit of a paradox because exhumation of a gas shale should cause the relaxation of some fraction of the gas pressure generated during maturation, especially after oil has cracked to gas. The mechanism for maintaining pressure even during relaxation accompanying exhumation is known as Skempton's behavior which is enabled by the relatively high compressibility of gas in pore space. Relaxation of rock stress allows the expansion of pore space but gas expands into this larger pore space without losing much of its pressure because of its high compressibility (Katahara and Corrigan, 2001). During exhumation, Skempton's behavior maintains pore pressure so that eventually the residual pore pressure exceeds the least stress within the rock, thus leading to late-stage natural hydraulic fracturing (Engelder and Behr, 2017).

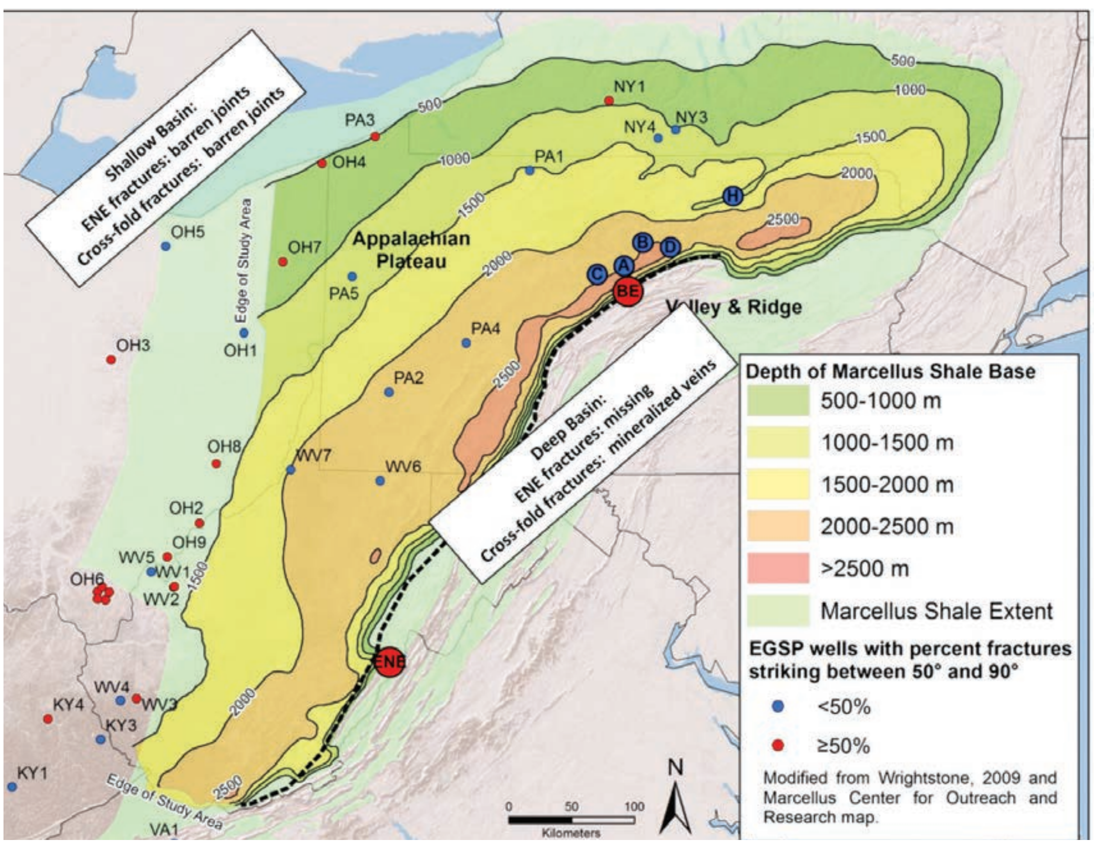

Figure 1. *A map of the Appalachian Basin showing the depth to the base of the Middle Devonian Marcellus Gas shale (Wrightstone, 2009). Map shows the general location of the Bald Eagle well (BE), industry wells (A,B,C,D, and H) Wilkins et al., 2014), Eastern Gas Shales Project (EGSP) wells, labeled by state as KY, NY, OH, PA, VA, and WV (Cliffs Minerals, 1982*

The argument that Skempton's behavior regulates pore pressure during exhumation is based on the distribution of fracturing in Appalachian gas shale (Figure 1). At shallow depths near the NW edge of the Appalachian Basin stacked gas shales including the Marcellus, the Geneseo, the Middlesex, the Rhinestreet, and the Dunkrik-Huron all carry a joint set parallel to the contemporary tectonic stress field (Lash et al., 2004). Sampling in the deeper portion of the Appalachian Basin suggests that this ENE joint set is missing (Evans, 1994; Wilkins et al., 2014). Cross-fold joints are generally without mineralization in the shallow rocks of the foreland portion of the basin whereas they are mineralized in the deeper core in the central basin. The interpretation for shallow but not deep ENE joints is that during exhumation to depths less than 2 km Skempton's behavior maintains a pore pressure sufficiently high to cause natural hydraulic fracturing driven by an evolving gas pressure that eventually exceeds the least stress (Engelder and Behr, 2017). Skempton's coefficient is a poroelastic property dictating the interaction between pore pressure and horizontal rock stress which allows the relaxation of gas pressure but at a fraction of the rate of relaxation of least stress during exhumation (**Figure 2**). Because of the stress-pore pressure coupling, least stress does not relax as fast with exhumation as suggested by earlier elastic models (Narr and Currie, 1982; Price, 1974).

Sufficient relaxation for natural hydraulic fracturing occurs only after more than 50% of the overburden is removed by exhumation as measured from the maximum depth of burial zmax and exhumed to z so that the fraction of the present depth is $(Z_{max} - z)/z_{max}$. The governing equation for poroelastic coupling of the minimum horizontal stress (S_{hmin}) to pore pressure (P_p) during exhumation follows:

Water Density	Biot-Willis	Rock Density	Poisson's Ratio	Onset of Compaction Disequilibrium	Skempton Exhumation	Consolidation Coefficient	% Increase in maturation-related pore pressure	Thermal expansion	Young's Modulus	Geothermal Gradient	Skempton Burial	Onest of Skempton Oil
1029	0.7	2700	0.3	1000	0.7	0.53	0.1	1E-05	26000	0.03	0.7	3000

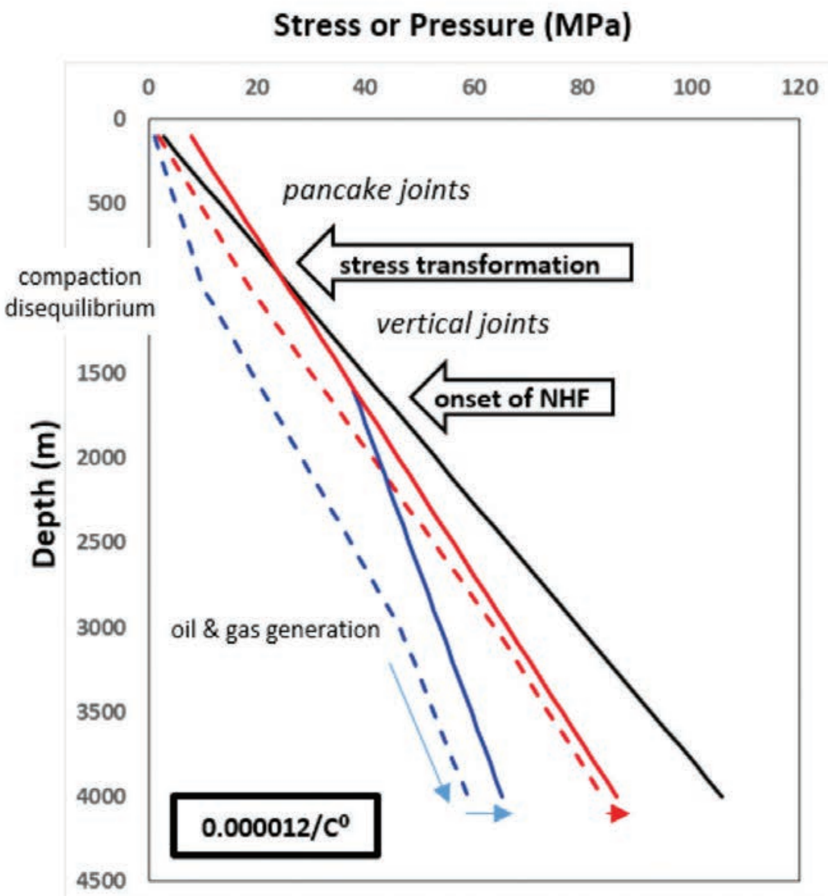

Figure 2. *Hypothetical stress-pressure-depth models for Appalachian Basin to 4,000m and completely exhumed. S_v – black line, P_p – blue line. S_{hmin} – red line. The burial portion of this model (dashed lines) is presented in more detail in Engelder and Behr 2017. The exhumation portion of this model is governed by Equations 1 to 3. The intrinsic properties are given in the key to this figure. The coefficient of thermal expansion for a shale (black box) controls the behavior in this Figure.*

$$\Delta S_{hmin} = S_{hmin}^{max} - \left(\frac{\upsilon}{1-\upsilon}\right)\rho_{rock} g(z_{max} - z) - \frac{\alpha_t E}{1-\upsilon}\Delta T + \left(\frac{1-2\upsilon}{1-\upsilon}\right)\alpha_{bw}\Delta P_p \quad 1$$

where α_{bw} is the Biot-Willis coefficient, ρ*rock* is the integrated density of the overburden, ν is Poisson's ratio, E is Young's modulus and α_t is the thermal expansion coefficient for the gas shale in question. The change in pore pressure during relaxation is governed by the Skempton effect according to

$$\Delta P_p = \rho_{rock} g(z - z_{max})\frac{B(1+\upsilon)}{3(1-\upsilon)}. \quad 2$$

where B is the Skempton's coefficient. B for black shale is calculated using

$$B = \frac{1}{1+\left(\frac{\beta_f - \beta_\phi}{\beta - \beta_s}\right)} \quad 3$$

where β is the isothermal bulk compressibility (e.g., 0.000153 MPa^{-1}), β_f is the isothermal pore-fluid compressibility (e.g., 0.00045 MPa^{-1}), β_s is the isothermal solid grain compressibility (e.g., 0.000014 MPa^{-1}), and β_ϕ is the isothermal pore-space compressibility (e.g., 0.00044 MPa^{-1}) (Katahara and Corrigan, 2001; Rice and Cleary, 1976). During exhumation, pore pressure continues to decrease by the Skempton effect until natural hydraulic fracturing is induced (**Figure 2**). Above the depth of natural hydraulic fracturing, pore pressure will follow that rock's fracture gradient which is the path that S_{hmin} takes during further exhumation. Even during fracturing, abnormal pore pressure does not drain, a result seen from several gas shales (Gale et al., 2014). This is largely because vertical joints do not rupture through the capillary seal bounding the gas shale (Engelder et al., 2014). ■

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Biographical Sketch

Terry Engelder, a leading authority on the recent Marcellus gas shale play, holds degrees from Penn State BS (1968), Yale MS (1972) and Texas A&M, PhD (1973). He is currently an Emeritus Professor of Geosciences at Penn State and has previously served on the staffs of the US Geological Survey, Texaco, and Columbia University. Short-term academic appointments include those of Visiting Professor at Graz University in Austria and Visiting Professor at the University of Perugia in Italy. Other academic distinctions include a Fulbright Senior Fellowship in Australia, Penn State's Wilson Distinguished Teaching Award, membership in a US earth science delegation to visit the Soviet Union immediately following the Nixon-Brezhnev detente, and the singular honor of helping Walter Alvarez collect the samples that led to the famous theory for dinosaur extinction by large meteorite impact.

Wednesday, November 8, 2017 | Session 2 | 1:05
Ahmad Ghassemi
Reservoir Geomechanics & Seismicity Research Group
The University of Oklahoma

Complex Fracture Network Creation in Stimulation of Unconventional Reservoirs

Summary
Shale reservoirs have heterogeneous geological and geomechanical characteristics that pose challenges to accurate prediction of their response to hydraulic fracturing. Experience in shale formations shows that stimulation often results in formation of a complex fracture structure. The fracture complexity arises from intact rock and rock mass textural characteristics, the in-situ stress, and their interaction with applied loads. Open and mineralized joints and interfaces, and contact between rock units play an important role in fracture network complexity which affects the rock mass permeability and its evolution with time. Currently, the mechanisms that generate these fracture systems are not completely understood, and are generally attributed to low in-situ stress contrast, rock brittleness, shear reactivation of mineralized fractures, and textural heterogeneity. This presentation will address issues pertaining to the design of a fracture network through interactions of hydraulic and natural fractures. Robust large scale numerical simulations of hydraulic fracture propagation in naturally-fractured anisotropic mudstones are presented. The effect of pore pressure distribution, in-situ stress anisotropy, and different completions techniques (including limited entry) will be explored in the presentation. Finally (time permitting), issues related to re-fracs and parent/child wells will be discussed with particular reference to fracture hits, using fully-coupled 3D poroelastic simulations.

Introduction
The idea of stimulation by hydraulic fracturing is to create a large volume of fractured rock with enhanced permeability.

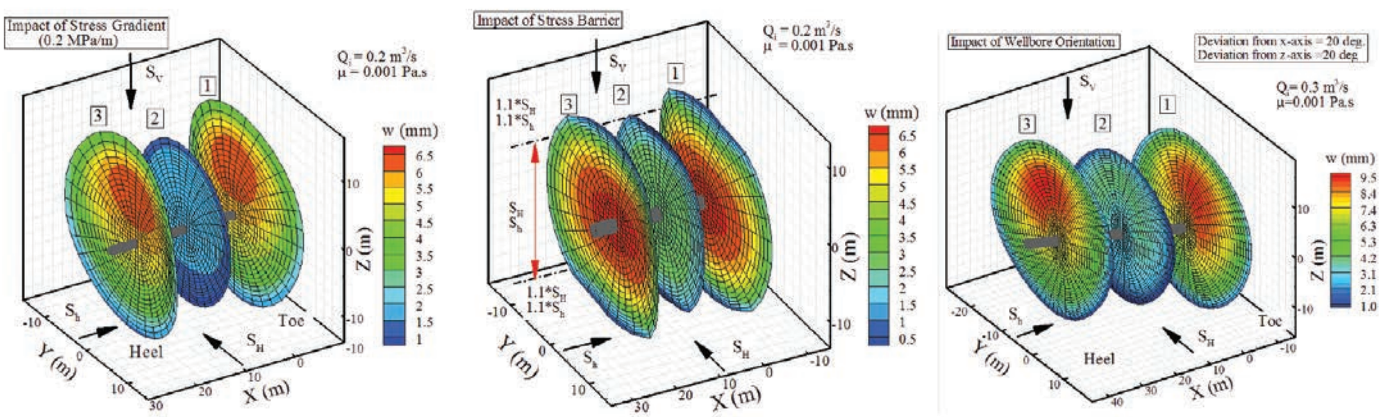

Figure 1. *Effects of in-situ stress gradient, in-situ stress barrier, and horizontal orientation (Kumar and Ghassemi, 2017).*

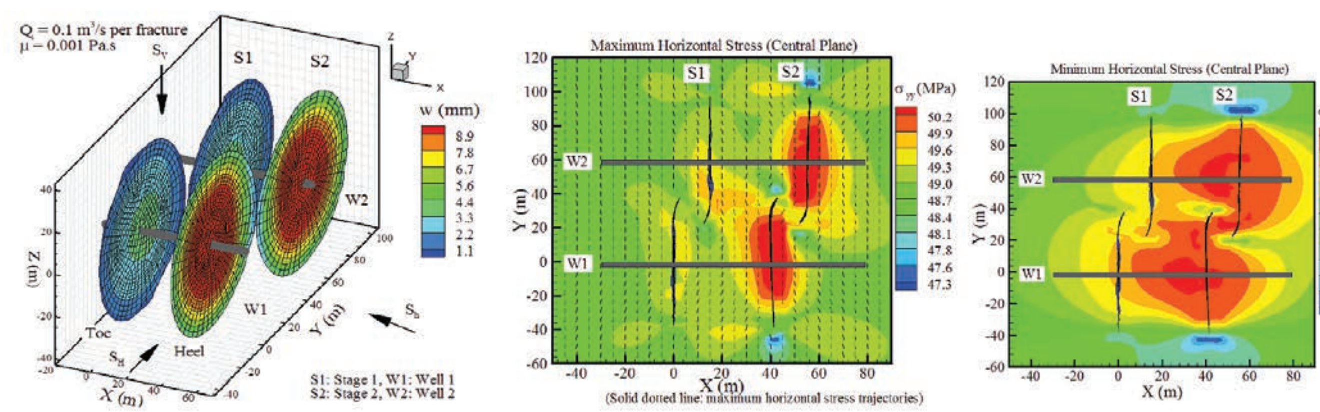

Figure 2. *Zipper fracturing of two horizontal wells with offset (Kumar and Ghassemi, 2017).*

Most field implementation of stimulation involves creation of multiple hydraulic fractures and stimulation of the neighbouring rock volume by compression and pore pressure increase. The geometry and propagation direction of a hydraulic fracture will mostly depend on the drilling direction of the horizontal well and the in-situ conditions. It is generally accepted that hydraulic fractures propagate perpendicular to the least principal stress. In addition to the in-situ stress, fracture growth will depend on many factors such as natural fractures, bed laminations, and other characteristics of a reservoir including the formation pore pressure in the reservoir. Stimulation treatments may result from slip on pre-existing critically stressed fracture systems and/or creation of new fractures. It is generally believed that fracturing is caused by both shear and tensile failure. Shear slippage is induced by altered stresses near the tip of the fractures as well as by increased pore pressure in response to leakoff through the fracture "walls". Improved understanding of these processes and design optimization can benefit from numerical simulations. In the following sections, some advanced complex fracture modelling is presented to explore some important physics involved and to illustrate some fundamental features of multiple hydraulic fracture propagation including hydraulic/natural fracture interactions.

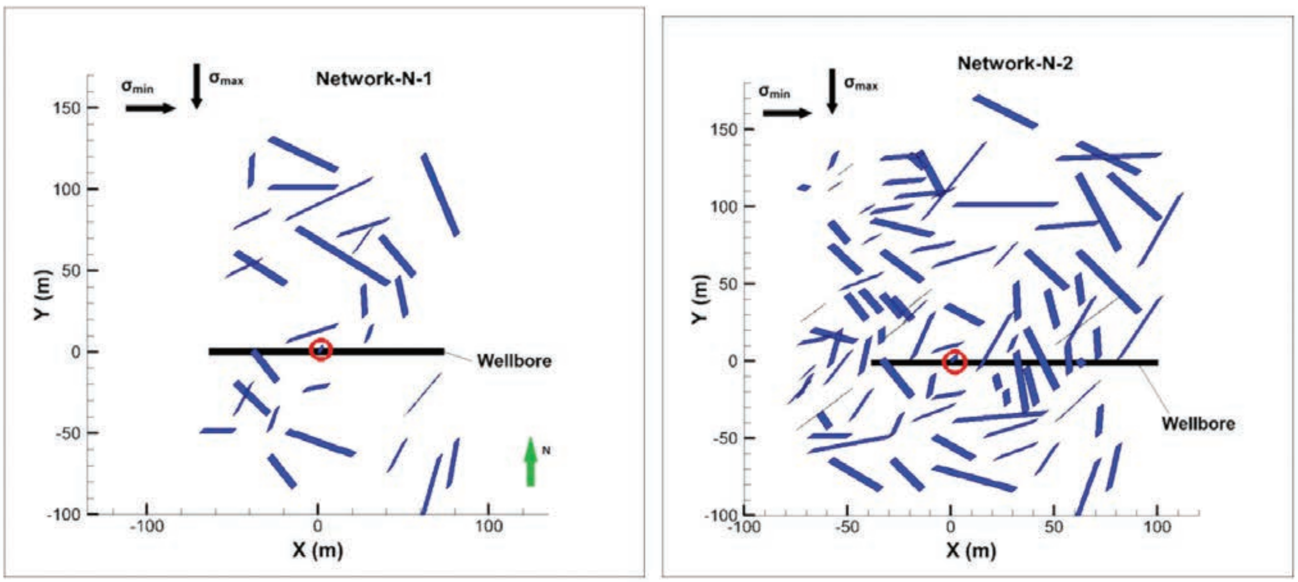

Figure 3. *Fracture networks N-1 and N-2 used in numerical simulations. Principal stresses are oriented in X-Y directions. Perforation location along the wellbore (black line) is identified by the red circle. Pre-existing natural fractures are presented in blue. Compressive stresses are taken positive. (Sesetty and Ghassemi, 2017)*

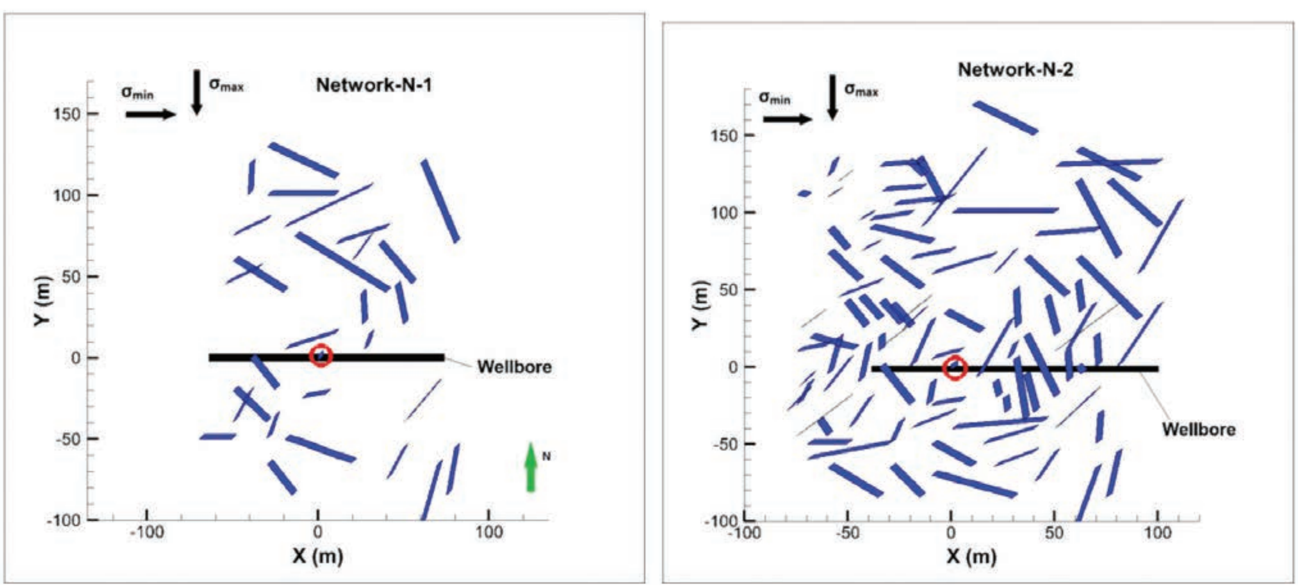

Figure 4. *Hydraulic fracture propagation in fractured shale. (a) fracture aperture, (b) pressure, (Sesetty and Ghassemi, 2017).*

Simulation Examples

In-situ stress conditions and stress shadowing or mechanical interaction among fractures are critical parameters in stimulation design. Mechanical interaction or stress shadowing is a function of spacing among fractures, net fluid pressure, and stress anisotropy and needs to be assessed in 3D. **Figure 1** illustrates the effects of in-situ stresses on multiple fracture geometries.

Zipper fracturing of two horizontal wells with offset between fractures from two wells is often suggested to be more effective in stimulation. Numerical simulations suggest that the problem of fracture coalescence and well communication can be mitigated, and relatively close horizontal wells can be stimulated.

Consider stimulation of the fracture network N-1 shown in **Figure 3**. The natural fractures are assumed to be in equilibrium with the initial stress state. The in-plane differential stress in this example is 5 MPa with 40 MPa minimum principal stress. Perforation location is indicated by a red circle along the wellbore in **Figure 3**. Slick water is injected at 20 bpm for 27 minutes. Assuming negligible fluid loss into the formation, the natural fracture geometry, aperture distribution, pressure distribution, shear displacements and status of all elements at the end of the simulation are shown in **Figure 4**.

Figure 4 shows hydraulic fracture growth is predominantly north-south. Hydraulic fractures are arrested at natural fractures at most of the intersection sites. Aperture distribution shows extreme variation along the fracture network; the highest fracture opening is seen along the segments of the fracture network that opened against the minimum in-situ stress. Fracture wings emanating from the natural fractures tend to have higher openings, however the parent natural fractures have very restricted openings because higher compressive normal stresses act on them.

Conclusions

Several numerical examples have been considered to study the effect of fracture spacing, offset, far field differential stress, and pore pressure change on stimulation. Perforation orientation with wellbore axis, spacing among fractures, and stress anisotropy, shows strong effects on the created fracture geometries. Higher in-situ stress contrasts produce fracture networks with extreme variation in fracture opening. Low angle natural fracture segments tend to close due to stress shadow even under low differential stress cases. When pore pressure changes caused by leak-off are considered, most of the unconnected natural fractures that are favourably oriented experience slip. The numerical results presented in this paper can provide insight when interpreting micro-seismic events associated with hydraulic fracture propagation. ■

Acknowledgments

The support of the University of Oklahoma Reservoir Geomechanics Joint Industry Project is greatly appreciated.

Biographical Sketch

Ahmad Ghassemi is the McCasland Chair Professor in the Mewbourne School of Petroleum & Geological Engineering, OU and is the director of the Halliburton Rock Mechanics Laboratory. He has a PhD in Geological Engineering and specializes in geomechanics for unconventional petroleum and geothermal reservoir development. He has been working on hydraulic fracturing and high-temperature rock mechanics research for the past 20 years with emphasis on modeling of multiple hydraulic fractures, coupled geomechanics/fluid flow modeling in naturally fractured reservoirs, wellbore stability analysis, induced seismicity, and experimental determination of reservoir rock properties. His teaching interests include reservoir geomechanics, numerical modeling, petrophysics, and stimulation.

Wednesday, November 8, 2017 | Session 2 | 1:40
Tobias Hoeink
Baker Hughes, a GE company

Hydraulic Stimulation in the Presence of Fractures

Summary

The only economical way to extract hydrocarbons from low-permeability shale reservoirs is to increase reservoir contact. Horizontal drilling, multi-stage completion, and hydraulic fracturing have proven key technologies in this respect. Yet, there is more to consider when engineering for optimal recovery on the quest for permeability. Many reservoirs are blessed with networks of natural fractures that are thought to act as hydrocarbon highways and contribute significantly to production. Focusing on fractured reservoirs, this presentation discusses how fractures across many length-scales contribute to permeability improvements that make unconventional reservoirs economically viable. We will discuss recent technology advances in fracture characterization and modeling, fracture network analysis techniques, and highlight case studies about the influence of fractures on stimulation and on the importance of integrated technology application for successful production.

Micro-crack Coalescence

Advanced models of fractures in geological materials can be used to understand and predict damage and fractures. **Figure 1** shows results from a mechanisms-based approach that translates fracture mechanisms into mathematically precise descriptions (Hoeink and Zubelewicz, 2016). Careful tests demonstrate the model's ability to reproduce behavior observed under uniaxial tension, compression, and under triaxial stress conditions. Examples of core plug and near-wellbore hydraulic stimulation models demonstrate emerging localized damage zones and illuminate the mechanisms responsible for permeability improvements during stimulation.

Natural Fracture Networks

Networks of natural fractures provide significant improvement in permeability that can be captured in reservoir models. **Figure 2** shows an example of field scale fracture network permeability estimation that uses local upscaling schemes (Hoeink et al., 2016).

Influence of Faults on Stimulation

The role of large fractures and faults on reservoir stimulation can be modeled with advanced modeling tools that simulate fracture propagation and the transport of fluid and proppant into hydraulically-driven and intersected natural fractures (Cruz et al., 2017). Simultaneous prediction of micro-seismic events allows model calibration with field observations. Results of this case study indicate that the presence of conductive faults can explain well interference patterns observed in the field.

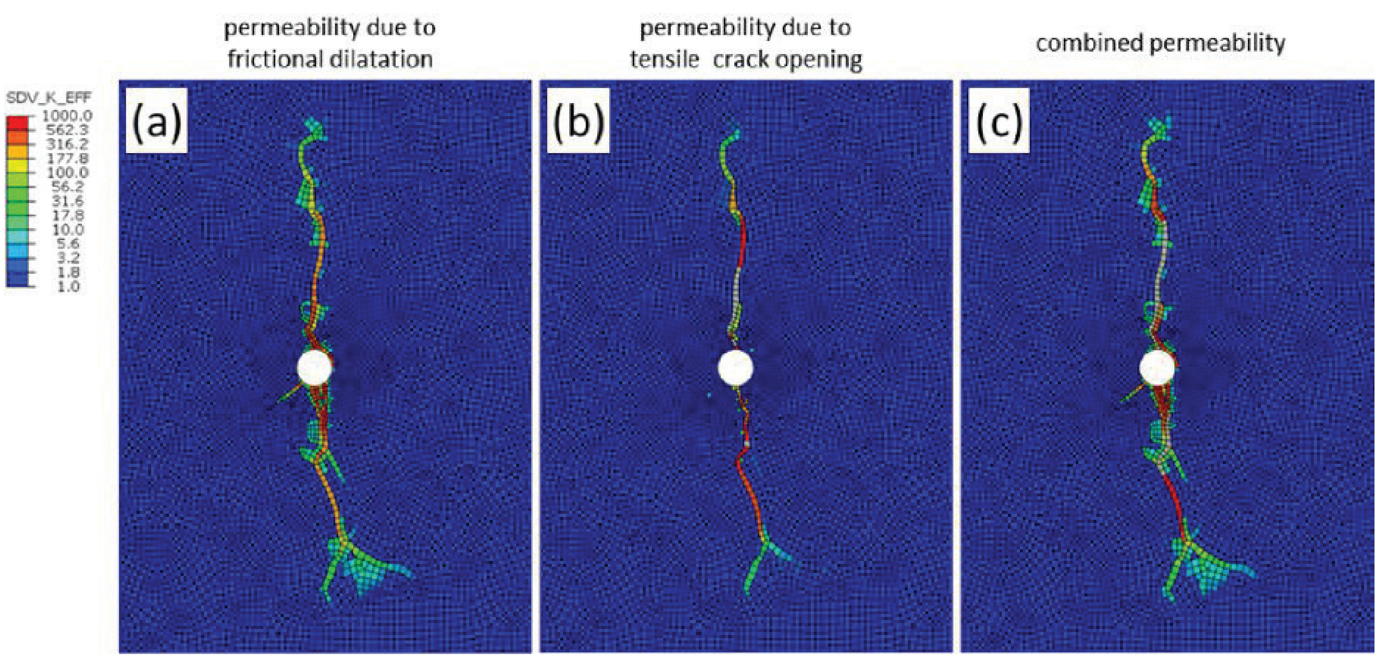

Figure. 1. *Distributions of fracture-induced enhancements of permeability caused by (a) frictional dilatation, (b) tensile crack opening, and (c) both mechanisms observed in mechanism-based fracture models in which permeability improvements are related to interlinked branches of micro-cracks. (Hoeink & Zubelewicz 2016, reproduced with permission).*

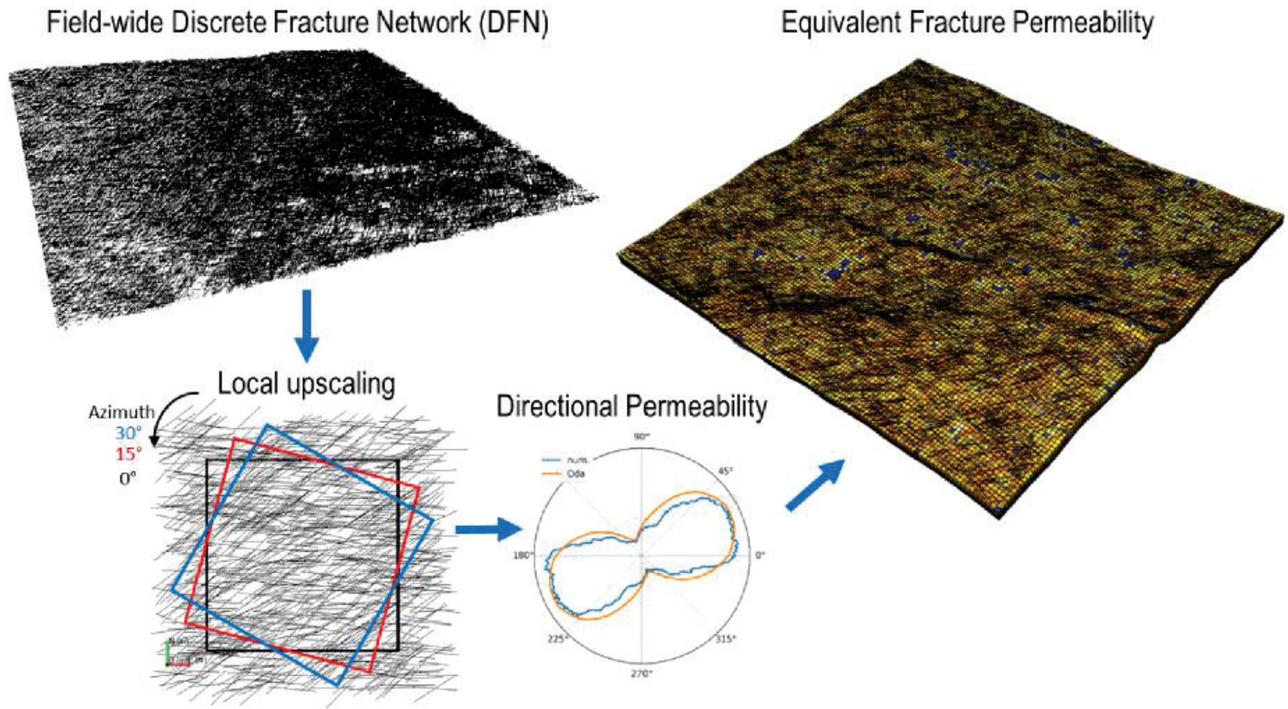

Figure 2. *The estimation of equivalent permeability from a field-wide discrete fracture network is commonly performed on local volumes. Consideration of directional permeability allows for estimates that significantly improve reservoir simulations.*

Hazard Avoidance and Completion Optimization

Reactivation of faults and creation of conductive pathways into aquifers are only some of the potential risks of subsurface operations. Avoiding hazards requires an integrated technology approach in which multiple disciplines work in close collaboration. Recently, Cazeneuve et. al. (2016) demonstrated that the combination of reservoir navigation, deep shear wave imaging, and micro-seismic monitoring enabled the imaging of fracture characteristics up to 100 feet away from the borehole, and identification of several faults along the lateral that were not identified seismically or within other previous data sets. Collectively, this information was instrumental in avoiding fault reactivation, allowed successful well treatment, enhanced production, and avoided creating a pathway into the underlying aquifer.

Acknowledgements

The author thanks Marc Holland for contributing DFN experience and imagery, and Baker Hughes, a GE company for permission to publish.

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Biographical Sketch

Dr. Tobias Hoeink leads interdisciplinary teams at Baker Hughes, a GE company, where he is responsible for the development of innovative digital technology solutions. Dr. Hoeink has 15 years of experience in numerical modeling, scientific computing, and research & development. He worked and published in computational fluid dynamics, rock mechanics, hydraulic fracturing, mantle convection, plate tectonics, planetary evolution, and recently in machine learning applications. Dr. Hoeink received a MS and a PhD in physics from Münster University in Germany.

Wednesday, November 8, 2017 | Session 2 | 2:35, 3:10
Ewerton Araujo, Sebastian Bayer
and **Marcus Wunderle**
BHP

A Holistic Approach to Geologic and Geomechanical Modeling in Unconventional Reservoirs

The development of unconventional shale oil and gas reservoirs has pushed the boundaries of subsurface models to a new level of higher collaboration between geoscience and engineering. The complexity of the reservoir stimulation by multi-stage hydraulic fracturing throughout rocks with the presence of natural fractures requires a holistic approach from the modeling perspective. In this sense, the challenge is to create workflows that allow the integration of geoscience and engineering models, by keeping it as simple as possible while maintaining the focus on the key drivers.

This presentation will cover an integrated workflow in the form of a 3D geo-cellular model, which allows for geologic and geomechanical modeling that lays the foundation for reservoir simulations models, and their applicability to field development scenarios and well completions optimization.

The geo-cellular approach covers the geologic and geomechanical attributes that impact the hydraulic fracturing of unconventional reservoirs. It starts by discretizing the reservoir in units of mechanical-stratigraphic properties; such as stiffness, based upon petrophysical analysis. The structural framework is enhanced by including over one hundred geo-steered wells, to ensure the grid resolution is properly defined to represent the key aspects of both geological and geomechanical models.

A key geological element incorporated is the presence of natural fractures, which was modelled using a Discrete Fracture Network (DFN). The DFN was built upon a systematic analysis of core data, borehole image logs, seismic attributes analysis, and populated across the geo-cellular model using the mechanical-stratigraphic units. The resulting model was further refined using geomechanical simulation of microseismic events.

The 3D Geomechanical model was built using the Finite Element Method (FEM) upon the geological model and populated with mechanical properties derived from petrophysical logs. The stress initialization was validated using 1D wellbore geomechanical models of a few pilot wells across the field, in particular, one well near the selected pad to ensure good constraint of mechanical properties and stress values. The model embeds the simulated hydraulic fracture from a stand-alone hydro-frac simulator and net pressures observed in the field in order to simulate the stress tensor update (stress shadows), and its impacts on microseismic events simulation, i.e., the slippage of natural fractures that become critically stressed.

The critically-stressed fractured volume (CSFV) and the hydraulic fractures were compared with field data such as chemical tracers to provide an image of the ultimate stimulated volume which serves as a basis for future reservoir simulation. The model can also be used for the optimization of spacing between wells and hydraulic fracture stages, using the expected stress shadows concept instead of a traditional geometrical design. ■

Biographical Sketches

Ewerton Araujo is the leader of a team of experts in geomechanics at BHP. With 15 years of experience in the petroleum industry he has applied geomechanics across the entire life cycle of oil and gas fields. He holds a Ph.D. and Master's degrees in Geomechanics from the Pontificia Universidade Catolica do Rio de Janeiro, and a BS in Civil Engineering from the Universidade Federal da Paraiba in Brazil. Currently, he is leading the implementation and leverage of cutting edge geomechanics technology at BHP with application of sophisticated Finite Element Method simulations by making the bridge between Geological and Engineering models, for both conventional and unconventional assets.

Sebastian Bayer is a Principal Reservoir Geologist at BHP working as a reservoir integrator for both conventional and unconventional projects. He has more than 10 years of industry experience focused on integrated fit-for-purpose reservoir modeling, static models designed with engineers to provide integrated solutions for dynamic simulation. He graduated from the University of Oklahoma with a MS degree focused in Structural Geology and Stratigraphy. He also holds a BS in Petroleum Geology from the Universidad Nacional de Colombia. His current interests focus on integrated reservoir characterization and implementation of discrete fracture networks (DFN) based on geologic scenarios to understand the matrix and fracture components of the system. This includes integration of well logs, petrofacies, seismic attribute volumes, and microseismic event clouds in relation to different geomechanical units and stress. His work is focused on single-well analysis and multi-well interference studies based on robust static parameters for projects to evaluate reservoir quality and production performance.

Marcus Wunderle is a Geoscience Manager at BHP. He has 10 years of experience in the oil and gas industry spanning conventional development, and unconventional exploration and development. Most recently, he has been working on the Haynesville. He is a graduate of Ohio University with a MS in geology, focusing on Geoscience Education, and a BS in Earth Science Education focusing in geology.

Wednesday, November 8, 2017 | Session 2 | Alternate Speaker
James Kessler, PhD, Senior Geologist
Occidental Petroleum Corporation

Impact of Clay Content on Elastic Anisotropy and Stresses in the Permian Basin Mud Rock Systems

TThe relationship between the horizontal elastic modulus, Eh, and the vertical elastic modulus, Ev, is a function of clay content in unconventional resource plays in the Permian Basin. Increases in clay content in the Permian Basin mud rock systems are associated with increases in elastic anisotropy, Eh/Ev. When elastic anisotropy is high, over ~1.5, calculated stresses increase and affect the results and interpretation of 1D geomechanical models, wellbore stability models, and hydraulic fracture models. To assess the significance of the impact of clay content and elastic anisotropy on the stress calculation, we analyzed data from 60 pairs of vertical and horizontal one-inch diameter core plugs, 120 plugs total, taken from three wells in the Permian Basin. The 4-inch diameter whole cores were collected from four different formations with lithotypes that included calcareous siltstones, carbonate debris flows, siliceous siltstone, calcareous mudstones, siliceous mudstones, and organic rich mudstones. Each sample was analyzed for clay content and mineralogy using FTIR and XRF techniques. Static and dynamic elastic properties, Poisson's ratio, and uniaxial compressive strength were measured in confined compressive tests. Static elastic anisotropy was calculated at discrete locations over a range of depths and lithotypes. Bivariate regressions between each vertical and horizontal static Young's modulus and a commonly available wireline log were used as a method to upscale static elastic properties from the triaxial core plug measurements to log scale. The upscaled Eh and Ev data were used as input to the vertical transverse isotropic, VTI, stress model and compared to the poroelastic plane-strain model. The results showed an increase in stress in the VTI model compared to the plane-strain model up to 2,500 psi when elastic anisotropy is high. When anisotropy is low, the models converge on similar stress magnitudes, as expected. The impact of the stress increase has a significant impact on 1D geomechanical models, bi-wing hydraulic fracture models, and wellbore stability models. Anisotropy increases proportionally with an increase in clay content and preliminary results indicate that a clay content of 4-5% can be enough to impact stress magnitudes. Higher calculated stresses can have significant business impact on well design, well spacing, SRV estimation, and more - all of which can significantly impact the bottom line.

Biographical Sketch

James Kessler is a senior geologist currently working as a geomechanics specialist in the Subsurface Technologies group at Occidental Petroleum. His work is focused primarily on the characterization of mechanical stratigraphy through the upscaling of elastic rock properties and rock strength from core to reservoir scale and the characterization of stress in the subsurface. James applies his work to solving wellbore stability problems and enhancing the quality of rock property and stress inputs to hydraulic fracture models. James has 15+ years of experience as a geologist in a variety of research, consulting, and petroleum industry roles that have been focused on structural geology, hydrogeology, and geomechanics. He has been at Oxy for ~4 years.

Notes

Notes

Abstracts

Oral Presentations
Day Two

November 9, 2017

Southwestern Energy
Spring, Texas

Thursday, November 9, 2017 | Session 3 | 8:10
Erica Coenen
Director, Engineering at Reveal Energy Services

Validating Completion Design Using Pressure Monitoring in Offset Wells

Summary
A new method has been developed and validated to estimate hydraulic fracture geometries based on pressure signals recorded from offset wells. The method relies on surface pressure gauges on the offset wells and lateral isolation (solid bridge plug) in the observation well only. No downhole tools are required in either the treatment or monitor well. This makes it a very nonintrusive and budget friendly method, which enables operators to make widespread comparisons of completion strategy across entire fields.

Besides determining final fracture dimensions, the pressure-based mapping method can determine the transient analysis as a function of time or pumped volume. This enables the analysis of diversion effectiveness, and quantifying the impact of offset producing wells. This paper covers a case study on parent well interaction.

Introduction
Given the heterogeneity and uncertainties inherent in the geology of ultra-tight reservoirs, the industry is working toward a solution that can determine fracture geometry information without relying heavily on geological interpretation. Operators are also looking for completions evaluation solutions that are less intrusive to their operations and can be deployed across entire fields.

The pressure-based method presented in this paper was created by an operating company, when their research and development team set out to find a better way to compare completion results across fields. It was designed to be a lower-cost alternative to other expensive treatment monitoring options, allowing an operator to gather information on every well in the field plan, rather than just on the science wells.

Traditional diagnostics rely heavily on rock properties, (e.g., rock stiffness) to calibrate velocity models or effective permeability for interpretation of diffusion rate. The developed pressure-based method is different because it is relatively insensitive to rock properties, as it is governed by a force (i.e., load) balance. Moreover, the load carried by a material is conserved, whether the media is compliant or stiff. This makes the analysis very data consistent and repeatable.

Methodology
Surface pressure gauges are placed on a monitor well to analyze fracture growth during treatment of nearby adjacent wells (see **Figure 1**). Because the monitor well is filled with water, an incompressible fluid that can convey pressure signals, poroelastic pressure signals can be used to indicate fracture growth geometry for the stages being treated. This includes fracture length, height, proppant distribution, and even fracture growth rate thousands of feet away from the monitor well.

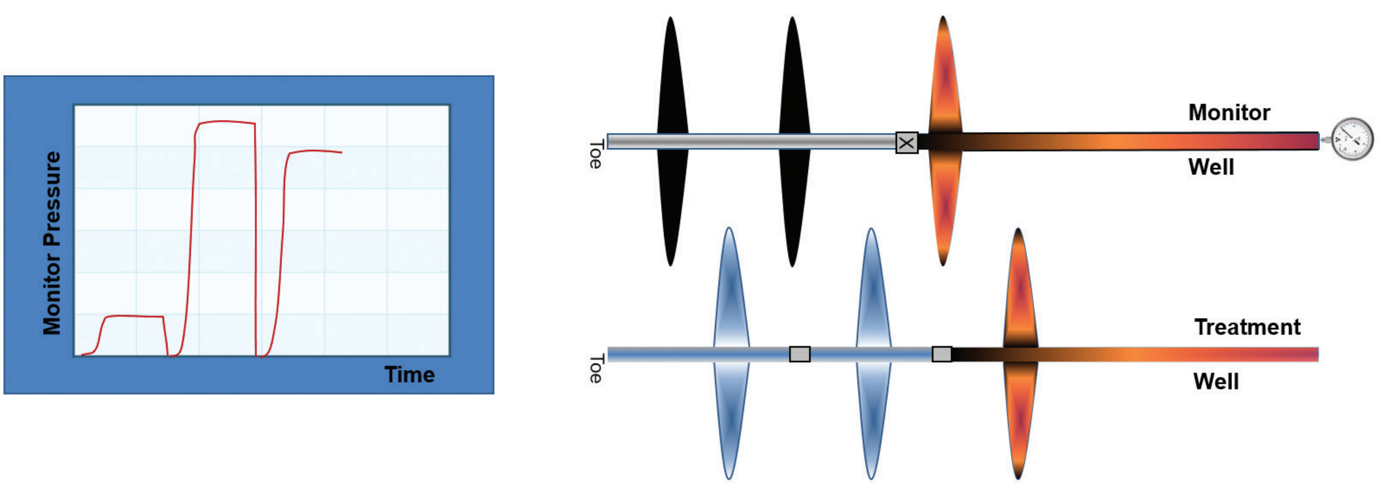
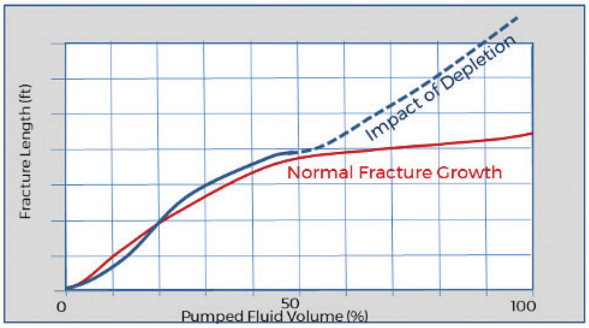
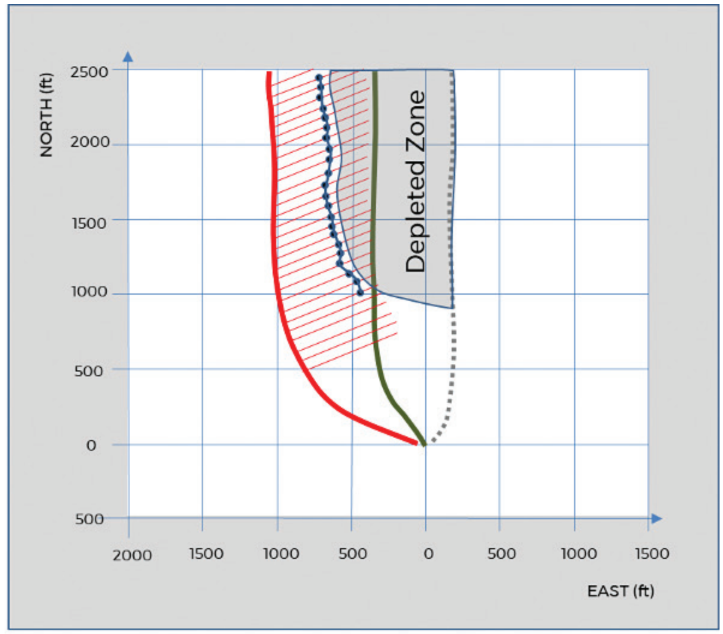


Figure 1. *Schematic setup for pressure-based fracture mapping (right), including isolated monitor stage on an offset well, treatment stages on the treatment well and recorded pressure signals (left).*





Case Study

Figure 2. *(Left) Accelerated fracture growth toward a depleted zone is observed during completion of a well. (Right) The contour of the depleted zone has been defined by the fracture acceleration point of successive stages.*

The pressure signals are recorded at 1 Hz with a resolution of 0.1 psi. This enables static analysis of the final hydraulic fracture dimensions and analysis of transient effects in growth rate. These effects may be due to completion design (e.g., diversion, fluid change) or geological factors (for example, local rock strength or stress state).

Depleted zones around previously produced wells are suspected of causing asymmetric fractures on wells being treated nearby. **Figure 2** (right) shows a baseline fracture growth curve as a function of pumped volume (in red). When a fracture grows into a depleted zone, the fracture growth rate will alter due to the perturbed in-situ stress state.

The pressure based mapping method can identify that point spatially for several successive fractures, thereby constructing the contour of the depleted zone. This data can be used to assess and alter treatment design, fluid volume, and help evaluate the effectiveness of strategies that were intended to mitigate the impact of the depleted zone on new fractures, such as during refracturing.

Conclusion

The pressure-based fracture geometry solution is intended to be used for full-field analysis. Its design enables an operator to gather fracture geometry results across a large area and compare them, to analyze the overall success of the completion design. This method also enables evaluation of treatment effectiveness, including analyzing the effects of depleted zones on nearby wells being treated.

Biographical Sketch

Erica Coenen is a technologist and expert in fracture mechanics. Erica joined Reveal Energy Services in July 2016. She has over 10 years of experience in modeling of damage and fracture at multiple length scales. She has been at the forefront of innovation for additive manufacturing and large-area electronics as a technologist at TNO, the Dutch national research lab. She holds five patents, has authored and coauthored more than 20 technical journal articles, and contributed to two books. Erica holds a PhD in Mechanical Engineering from the Eindhoven University of Technology in the Netherlands.

Thursday, November 9, 2017 | Session 3 | 8:45
Dan Kahn, Jamie Rich, Ken Silver, and David Langton,
Devon Energy
Martin Karrenbach, Steve Cole, Andrew Ridge, and Kevin Boone,
OptaSense

DAS Microseismic Monitoring and Integration with Strain Measurements in Hydraulic Fracture Profiling

Introduction

A treatment well equipped with a Distributed Acoustic Sensing (DAS) fiber-optic system can be used as an observation well for strain and microseismic activity during hydraulic fracturing of the same (in-well) or a neighboring (cross-well) treatment well. A variety of physical effects, such as temperature, strain and microseismicity can be measured and correlated with the treatment curves in the injected subsurface area to enhance our understanding of the reservoir.

Cross-well DAS microseismic data correlate strongly with low-frequency cross-well strain measurements that are commonly used to study inter-well communication. The microseismic data can also be used to estimate diffusivity in the reservoir during hydraulic stimulation. Combining the strain measurements, microseismic data, and diffusivity estimates provides an opportunity to better understand the evolution of the fracturing program and build an improved reservoir description.

DAS Microseismic Data

A fiber-optic cable was installed in a treatment well in the Meramec formation (Karrenbach et al., 2017) covering the entire length of the well from surface to target depth, resulting in approximately 1000 recorded channels. During the treatment of two wells (A and B) as shown in **Figure 1**, temperature, strain, and microseismic activity were measured.

During treatment of the well containing the fiber, three stages were recorded, and despite significant treatment-related noise, hundreds of events were detected and mapped. While treating a nearby well, 30 stages were recorded, resulting in over 4000 detected and mapped events due to the increased signal to noise ratio. Examples of crosswell microseismic events are shown in **Figure 2**. Spatially mapped event locations for a single fracturing stage (stage 15 in well B) are shown in **Figure 3**. Events are mapped up to 500 meters from the observation well A, as shown in **Figure 3**.

Correlating Microseismic to Low-frequency Strain

While we used a standard range of frequencies for microseismic analysis, at a lower frequency range we can measure crosswell strain. Temperature and strain effects can be intermingled therefore specialized data processing was applied to remove the temperature effects as much as possible and enhance the strain signatures. After obtaining differential strain estimates, we successfully correlated those signatures to the evolution of microseismic events in time and space.

Figure 4 shows the low-frequency strain estimate after suppressing temperature-related effects. The strain values are shown on a relative radian scale with yellow indicating positive strain changes, blue negative and green no change. The data cover a spatial extent of 650 meters and a period of 3.5 hours. Surface and bottomhole pressure, surface and bottomhole concentration, as well as slurry rate curves are shown on the same time scale of the strain recording, so that a temporal correlation between injection characteristics and strain changes can be made. In addition, DAS microseismic events are indicated by the black dots as an overlay to the strain changes.

The changes in injection behavior over time correlate directly with the observed changes in strain for each of the individual treatment cycles. When the treatment cycle stops, the strain changes diminish significantly. The sensor channel nearest the stage location shows the greatest strain change and coincides with a rapid onset of microseismic activity. The fluid/rock interaction manifests itself both in the low-frequency strain field and in the microseismic activity that is triggered when certain stress thresholds are exceeded in the reservoir.

Fluid/Rock Interactions

To investigate the process of pore-pressure diffusion and the potential for triggering microseismic events we follow the approach described in Hummel et al (2012). Various linear and non-linear approximations can be used to fit trigger fronts to the envelope of observed microseismic events(Cole et al., 2017). One of the key parameters obtained in this process is hydraulic diffusivity. A standard R-T plot is shown for one stage in **Figure 5**. A trigger front has been estimated for stage 20 and overlaid on the microseismic distance versus time distribution. Shortly after the fluid injection is initiated, strong strain changes are detected and the microseismic activity commences. The activity ceases with the end of the first treatment cycle.

Figure 1. *Map view of observation well A and treatment well*

Conclusions

The analysis of this DAS data set demonstrates that current fiber-optic technology can provide enough sensitivity to detect a significant number of microseismic events. Reservoir properties such as hydraulic diffusivity can be directly estimated from the DAS microseismic data. Strain changes and trigger front behavior correlate with injection rate changes. Activation of microseismic events along fluid pathways indicates reservoir heterogeneity. Combining the analysis of microseismic activity with the cross-well strain measurements contributes to understanding hydraulic diffusivity, heterogeneity and propagation of fractures helping to ensure that the treatment program achieves its desired results.

References

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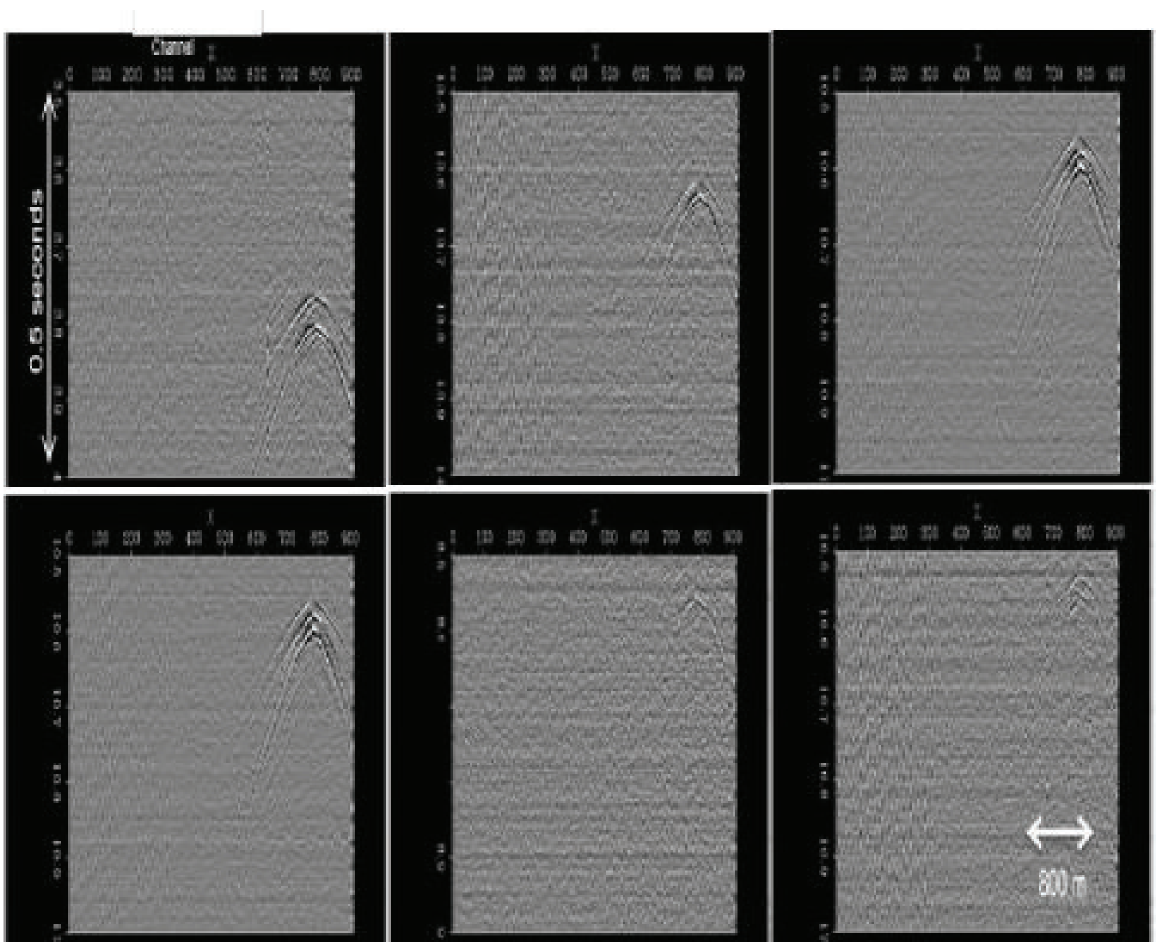


Figure 2. *Typical event wave forms with various signal and noise conditions recorded on the DAS fiber-optic sensor array in well A. Simple events show a single P and S-wave arrival, while others show complex wave forms and rapid repetitions of events induced by the rupturing process.*

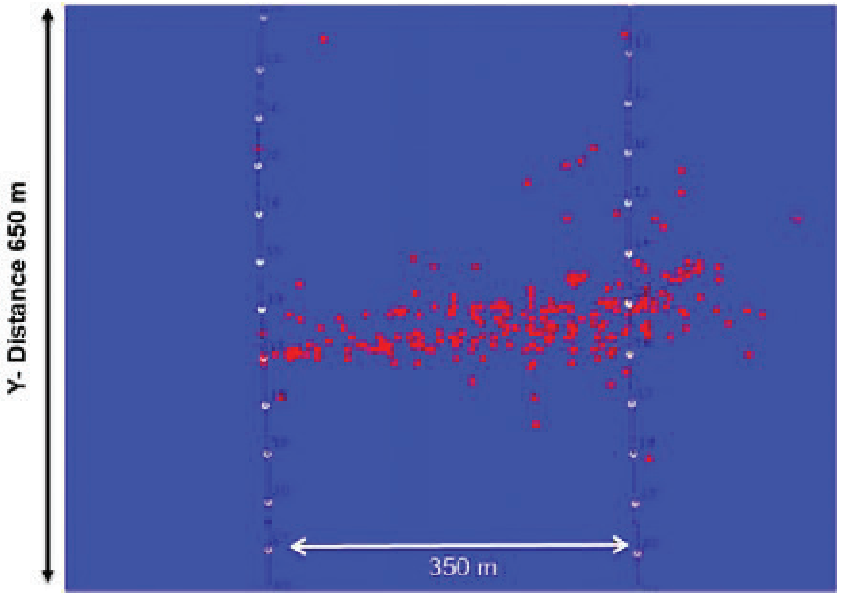


Figure 3. *Event map of a single stage. Treatment well B on the right, fibered DAS observation well A on the left.*

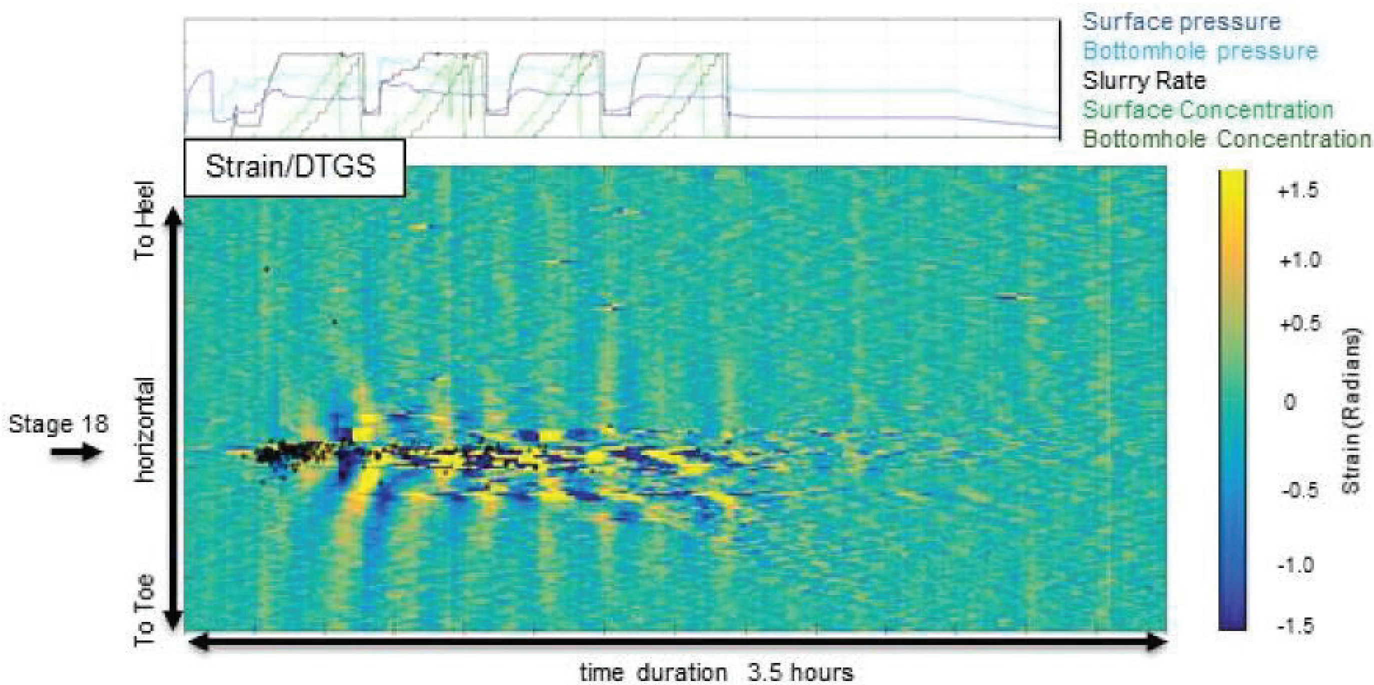


Figure 4. *Low-frequency strain estimate for one stage after suppressing temperature related effects. Microseismic events, denoted by black asterisks, have been overlaid on the strain data. There is a clear correlation between features in the strain data and the microseismic events, as well as with the treatment curves shown above.*

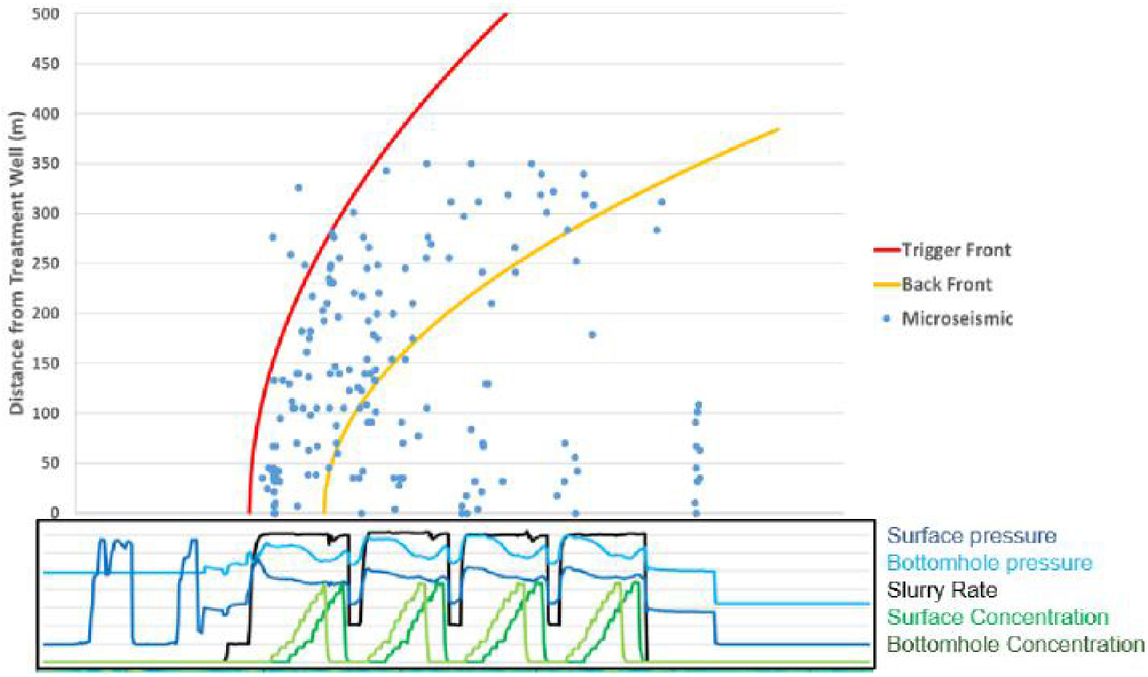


Figure 5. *R_T plot for one stage plotting distance of each microseismic event from the treatment well versus arrival time. A trigger Front has been fit to the data from which diffusivity can be estimated.*

Karrenbach, M., Ridge, A., Cole, S., Boone, K., Kahn, D., Rich, J., Silver, K. and Langton, D., 2017, DAS Microseismic Monitoring and Integration with Strain Measurements in Hydraulic Fracture Profiling, URTeC Conference, Expanded Abstracts.

Acknowledgments

We are grateful to Devon Energy and OptaSense Ltd for permission to publish the results. In particular we would like to thank the following groups at Devon that supported this project: the Strategic Innovation Group, the Anadarko Business Unit, the Technology Completion Engineering Group, and the Reservoir Technology & Optimization Group.

Biographical Sketch

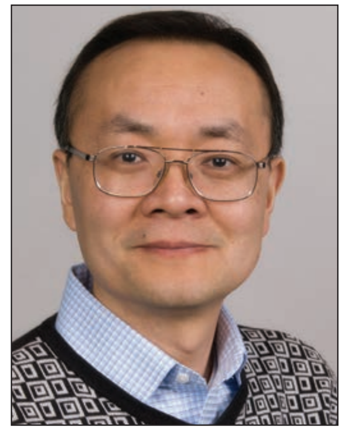
Dan Kahn, Geophysical Advisor, Devon Energy After graduating from Brown University (2001) with a BS in Geology/Physics/Mathematics, Dan Kahn received his MS in Geophysics from Georgia Institute of Technology (2004) with a thesis, Concentration of Methane Hydrate: A Study of the Blake Ridge. He then earned a PhD from Duke University (2008), working at the Krafla, Iceland geothermal station and the Basel Hot Dry Rock Project with a dissertation, Crack Propagation in Hydro-Fractured Reservoirs: A Study Using Double-Difference Location Techniques. Dan worked at Exxon as a Senior Geophysicist (2008-2011), during which time he did structural and stratigraphic interpretation of the Austin Chalk Trend and was lead survey designer for the Ranridge and Papua New Guinea projects. He was an Exxon Gold Service Medallion recipient (2008). Dan joined ION Geophysical in 2011, where he specialized in the characterization of unconventional reservoirs through microseismic fracture imaging and analysis. He was co-developer of ION's Java-based microseismic tool kit, authoring 7 patents. Dan moved to Devon in 2015 where he is responsible for overseeing data acquisition and analysis for the description of the dynamics of unconventional reservoirs, including microseismic, magnetotelluric, time domain electromagnetics, and optical fiber techniques. Dan was also a USA Olympic Trials qualifier in the Marathon with the "A" standard.

Thursday, November 9, 2017 | Session 3 | 9:40
Rongmao Zhou and Jarrett Pierce
BHP Petroleum

Focal Mechanism Solutions of Microseismic Events from Hydraulic Fracturing Monitoring: A Case Study in the Eagle Ford Shale

Microseismic monitoring of hydraulic fracturing treatments is one of the critical diagnostic tools utilized to evaluate how successful the well completion was, and to understand the fracture geometry and fracture complexity. To go beyond the "dots in the box", this paper presents a focal mechanism of all microseismic events located with a surface monitoring array for a microseismic monitoring project in the Eagle Ford Shale, with detailed analysis of one stage as an example to demonstrate the value of the moment tensor inversion. The decomposition of focal mechanism solutions indicates that the microseismic events are dominated by shear component. Fracture orientation and frac-hits obtained from microseismic data were cross-validated with distributed temperature sensing (DTS) observations and fault mapping. ■

Biographical Sketch



Rongmao Zhou received a Ph.D. from Southern Methodist University and a B.S. from Peking University (China), both in geophysics. He has more than 20 years of working experience both in academia and the oil & gas industry. His expertise includes microseismic data processing and interpretation, time-lapse reservoir monitoring, source mechanism inversion, earthquake seismology, and induced seismicity monitoring. He is currently a Senior Geophysicist at BHP.

Thursday, November 9, 2017 | Session 3 | 10:15
R.A. Hull, R. Meek, H. Bello
Pioneer Natural Resources

Case History of Integrating DAS Fiber-Based Microseismic and Strain Data for Monitoring Horizontal Hydraulic Stimulations

Summary

Distributed Acoustic Sensing (DAS) optical fiber for downhole geophysical and geomechanical measurements is a fairly new technology the industry is utilizing to better characterize hydraulic stimulations. Data were acquired with a vertical observation well that was instrumented externally with dual and single mode fiber optics for strain, acoustics (DAS), temperature (DTS), and external pressure gauges as well as internally instrumented with conventional tiltmeters and geophones. We used this instrumented well multiple times to record a number of nearby offset horizontal hydraulic stimulations as well as for a 3D/4D vertical seismic profile (VSP).

By using several tools, we can more accurately determine the height and length of the hydraulically stimulated zone to calibrate fracture models and determine where to place future horizontal wells during our field development.

While numerous papers can be written about the data collected, this paper focuses mainly on the integration of microseismic data and strain data acquired with fiber. In summary, by employing multiple sensors, including a fiber based DAS system, we are able to better characterize the stimulation as well as relate and understand key physical processes occurring within the hydraulic stimulation.

Introduction

In 2013 Pioneer Natural Resources installed a fiber optic system on the outside of a vertical well for the purposes of understanding the offset horizontal stimulations during field development and to record completion and production inflow into the vertical well. This deep well in the Permian basin was equipped with downhole pressure and temperature gauges as well as the fiber optic cable for DAS (Distributed Acoustic Sensing) and DTS (Distributed temperature Sensing) measurements. In 2015 and 2016 Pioneer stimulated a number

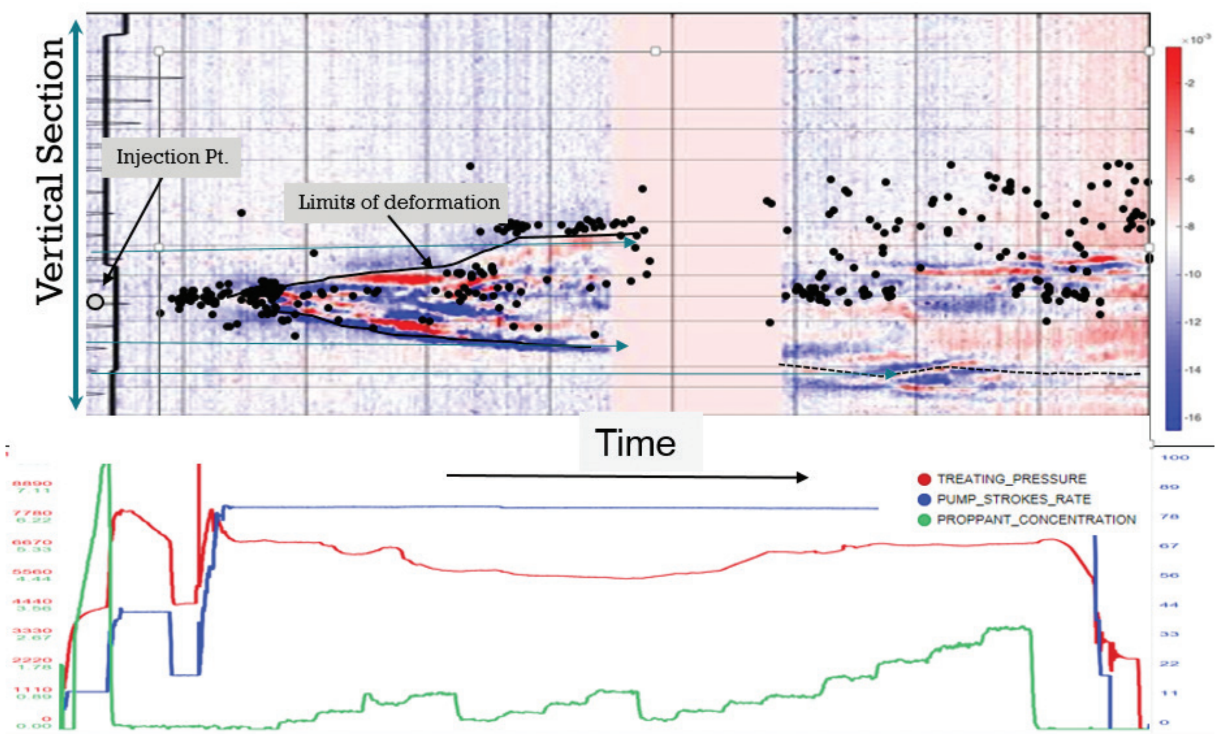


Figure 1. *shows strain data recorded over one completion stage with an overlay of the microseismic data. Units are nanostrain/sec. Note here in the strain data for a number of tens of minutes there is no growth in height but then stair steps upward and then contained again.*

of offsetting horizontals near this observation monitor well to confirm our understandings of pressure, temperature, strain, presence of proppant, fluid, and for microseismic (MS) activity. In addition to actively monitoring in real time the offset wells during their stimulations, we also tagged the proppant and ran a gamma ray (GR) tool over the vertical well after the offset hydraulic stimulation was completed to determine the presence or absence of radioactive (RA) tracers from the offset well stimulation. Lastly we recorded a multi-azimuthal 3D/4D (varying in azimuth, offset and time) VSP before, during and after the stimulation along with a traditional zero offset VSP acquired with conventional geophones. By measuring a number of effects of the offset stimulations we have been able to better understand and calibrate our data and tools, understand the multi-dimensional effects of the stimulations on the adjacent reservoir rock, as well as note some interesting effects observed in the datasets.

Method and/or Theory

DTS measurement patents extend as far back as 1989. Laurence (2001) demonstrated the use of fiber optic sensors for oil field wellbore monitoring. Advances in the technology and patents were occurring through the 2000s. Holley and Hull (2011), demonstrated the effective use of DTS and microseismic for a horizontal Barnett stimulation. Over the past eight years DAS has been used to understand completions and provide qualitative acoustic measurements of the fluid going through clusters and entering the formation during the hydraulic stimulation. Some of the first papers were by Shell (Molenaar M. et al. 2011) describing the first downhole E&P field trial of DAS. Current research in DAS is mainly focused on understanding completion efficiency. As it relates to cross well monitoring, Webster et al. 2013, from Shell published a good article describing DAS and offset well interaction. Silixa (Parker et al. 2014) highlights iDAS (intelligent DAS) recording of strain along a fiber as well as the aspects of fiber signal, fidelity, acoustic bandwidth and dynamic range as it relates to geophysical seismic applications.

Conclusions

Tagged proppant from the offset well did not reach the observation well. This suggests the hydraulic fractures did not directly contact the observation wellbore. We did record in the strain, MS, tiltmeter, and pressure instrumentation an increase in total height through time of the stimulation responses related to the pumping of the offset horizontal stimulations (**Figure 1**). DAS strain data was relatively clear, and height as imaged in the strain data ties well to our geomechanical understanding that fluid and pressure stay contained for set periods of time before breaking out into new rock. We believe the fiber may help us understand the relationships of low frequency strain, and MS, to the geomechanical processes taking place in these world class reservoirs.

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Biographical Sketch

Robert Hull is a Geoscience Advisor for Pioneer Natural Resources and is currently assigned to the Geophysics Technology Group. Robert has over twenty-five years industry experience. He has a strong background in conventional and microseismic acquisition and interpretation. He is further experienced in seismic stratigraphy, sedimentology, and geomechanics. He is a leader in 3D and microseismic acquisition for Pioneer. Recently he has been working with fiber based technologies, geomechanics, and microseismic to help characterize hydraulic stimulations primarily in the Eagle Ford formation of South Texas and Permian Basin in West Texas. He has also worked in Business Development, the Barnett Shale Asset Team, as well as internationally in West Africa and South Africa for Pioneer. He has previously worked as a geophysical specialist for Maxus Energy-YPF-Repsol in southeast Asia and the United States. Mr. Hull earned a bachelor's degree in geology from the University of Rochester and a Master's degree from the University of Texas at Dallas.

Arman Khodabakhshnejad, Yamina Aimene, Nirav Mistry, Aissa Bachir, Ahmed Ouenes
FracGeo

A Fast Method to Forecast Shale Pressure Depletion and Its Application in Poro-Elasticity Modeling and Prediction of Mid and Far Field Frac Hits

Summary

The production from a hydraulically fractured unconventional well depends on the stimulated permeability and its interaction with the naturally fractured background permeability. Since the propagation of a hydraulic fracture is often asymmetric, the ensuing pressure depletion depends on this asymmetric behaviour. An analytical asymmetric tri-linear model to approximate pressure depletion is presented. The model uses asymmetric frac design results as input and estimates the pressure depletion around a parent well. This tri-linear model was combined with our poro-elastic geomechanical modeling simulator to capture the physics created by the depleted pressure sink zone.

The pressure depletion is determined at an Eagle Ford well using the tri-linear model. Hydraulic fracture modelling of a child well located near a parent well highlighted the potential of developing a frac hit if geological features in the area were creating fluid and pressure conduits. A similar observation is made for a Wolfcamp well where a fault affected the nearby stage causing interference between potential stacked wells.

With the increasing number of infill unconventional wells, the integration of the asymmetric tri-linear model and our geomechanical simulator presents the necessary completion modelling tool to quickly, yet accurately design hydraulic fracturing while preventing frac hits.

Introduction

Many development scenarios do not account for the risks of well interference and well performance degradation resulting from infill and stacked wells planned too close to each other. These well interference problems could start during the fracing process and create frac hits that could cause major damages if appropriate measures are not taken. The potential damage includes wellbore integrity problems, and casing collapse, which could be prevented if identified prior to completion. To handle well interference, a geomechanical simulator needs to be deployed.

The geomechanical framework needs accurate mathematical representations of the driving in-situ parameters of the frac-hit physics:

1. the geological parameters like fractures and faults,
2. the non-uniform local stress field, and
3. the depleted zones due to the production of parent wells.

To capture the coupling between fluid pressure and solid stress in the reservoir during the hydraulic fracturing process and the underlying physics of the frac hit, poro-elasticity modelling in our reservoir geomechanics software module is used.

In this work, first the asymmetric tri-linear model is developed and validated. The generated depleted zone is exported to our poro-elastic geomechanical modelling simulator as input. A real Eagle Ford case is considered to show the effect of depleted zone and its potential in developing frac hits in the area where geological features are exploited as preferred fluid conduits. A Wolfcamp well is used to illustrate the potential vertical interference that may occur near a fault.

Asymmetric Tri-Linear Model

The tri-linear model was developed based on initial work of Brown et al. (2011). The tri-linear model considers 3 different regions where the Darcy's flow equation is rewritten by using dimensionless variables. The coupled equations are solved in the Laplace domain to estimate the wellbore pressure. Our improved tri-linear model uses the results of the asymmetric frac design as input (Paryani et al., 2016). A history-matching process is used to adjust the asymmetric tri-linear parameters and to estimate the key reservoir properties (inner reservoir permeability, outer reservoir permeability, reservoir thickness and porosity). Then, it is used to calculate the production and depleted zone that is further provided to our poro-elastic geomechanical simulator where the evolution of fluid pressure and rock stresses are simultaneously solved using the Material Point Method (MPM). The fluid flow and rock deformation equations are coupled based on the poro-elasticity theory introduced by Biot (1941).

Modeling Lateral Far Field Frac Hits near Depleted Zones

The effect of geological conduits, in presence of pressure depleted zone, on the hydraulic fracturing and its potential in developing frac hits is highlighted on the 9 stages Eagle Ford well. A hypothetical child well was planned near an existing parent well. This child well position could cause the development of a frac hit (Ouenes et al., 2017).

Figure 1 shows the pore pressure in the reservoir for different scenarios corresponding to the infill child well. Results show a potential frac hit when the child well is near the fault and the depleted zone. In this case, a direct communication is established between stage 4 of the parent and child wells and a noticeable pressure increase in the parent well is observed due to the fluid coming from stage 4 of the child well (reduction of the blue zone at stage 4 of the parent well).

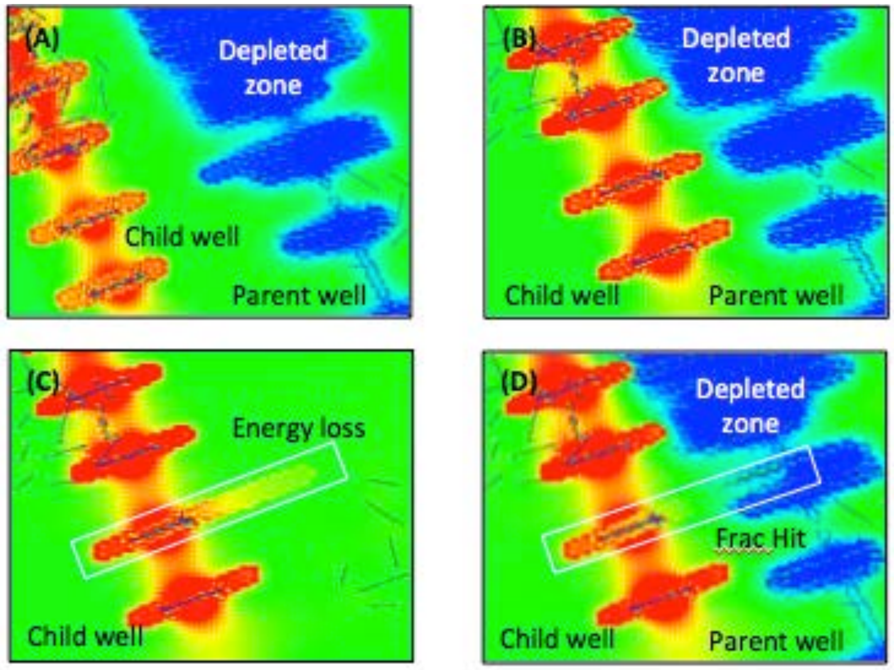

Figure 1. *Pore pressure at the end of hydraulic fracturing of the well (red is high pressure): (A) with the infill well at far position, (B) with the infill well at near position without the sub-seismic fault, (C) with the infill well at near position with the sub-seismic fault and without the depleted zone, and (D) with the infill well at near position with the permeability of the sub-seismic fault.*

Modelling Vertical Frac Hits in the Wolfcamp

Figure 2 shows a situation encountered in a Wolfcamp B well that affected the production of a lower Spraberry well. The presence of the fault shows that a large part of the fracing energy seems to be propagating vertically and lowers the pressure at stage 9. That reduction in pressure at stage 9 leads to a poorly stimulated stage and a potential frac hit with a nearby well stacked above the fraced well.

Conclusions

An asymmetric tri-linear model is used to predict pressure depletion. The model allows the simulation of the physics created by the pressure sinks as it interacts with the complex geologic features such as faults and natural fractures. Application of this model for an Eagle Ford and Wolfcamp well shows that the presence of a geological conduit like a fault changes the performance of hydraulic fracturing and sometimes provides a high permeability zone that transfers the energy of the hydraulic fracturing fluid to locations far from expected hydraulic fracturing fluid reach.

The geomechanical modeling of hydraulic fracture propagation in naturally fractured shale using the derived pressure depletion unveils the complex phenomenon that prevents the efficient stimulation of the rock. Thus, it can be used in conjunction with the geologic model of the natural fractures to predict the potential risks of frac hits.

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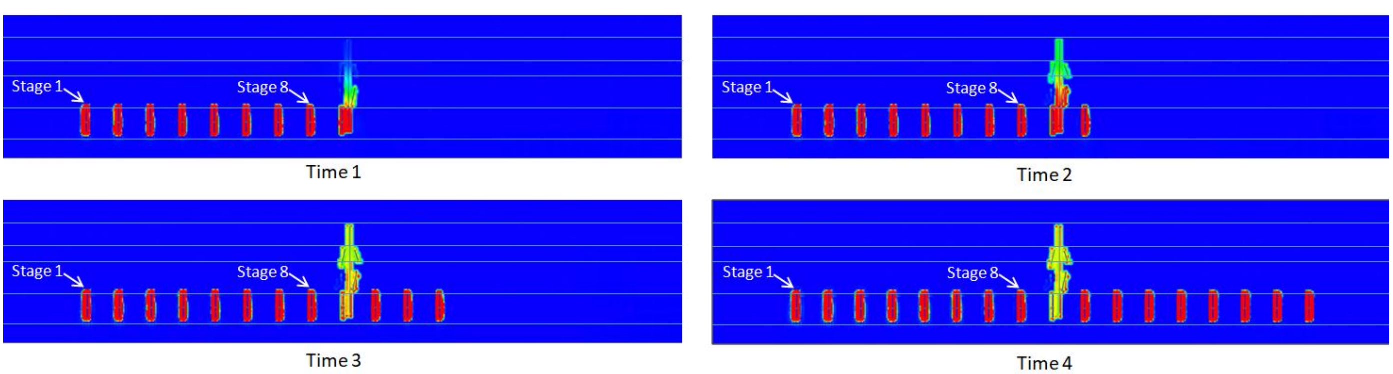

Figure 2. *Variation of pressure during hydraulic fracturing and loss of energy at stage 9 near the fault (Red is high pressure).*

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Paryani, M., Poludasu, S., Sia, D., Bachir, A., Ouenes, A. (2016). Estimation of Optimal Frac Design Parameters for Asymmetric Hydraulic Fractures as a Result of Interacting Hydraulic and Natural Fractures - Application to the Eagle Ford. Society of Petroleum Engineers. doi:10.2118/180460-MS

Biographical Sketch

Arman Khodabakhshnejad received a PhD in Petroleum Engineering from the University of Southern California, and an MS degree in Petroleum and Chemical Engineering from the Sharif University of Technology. Arman is a geomechanics specialist at FracGeo and works with a team of continuum mechanics experts to address various problems in modeling hydraulic fracturing in general and more specifically the interaction between hydraulic and natural fractures. He specializes in numerical modeling, reservoir simulation, coupled solid-fluid interaction, and geomechanical modeling.

Notes

Dr. W. Lasing Taylor, Senior Research Scientist
Energy & Geoscience Institute, University of Utah

Optimized Recovery from Unconventional Reservoirs: How Nanophysics, the Micro-Crack Debate, and Complex Fracture Geometry Impact Operations

Biographical Sketch

Dr. Taylor is Senior Research Scientist at the Energy & Geoscience Institute, University of Utah. Lans began his career as a field geologist with the USGS in 1994 and received his PhD from Stanford University in 1999. In Houston, he worked ten years as a structural geology specialist for Anadarko Petroleum, five years as an independent consultant, and 3 years with Talisman Energy. His current research at EGI examines the effects of mechanical stratigraphy on subsurface stress heterogeneity to improve our understanding of how natural and hydraulically stimulated fractures propagate through layered materials.

Thursday, November 9, 2017 | Session 4 | 1:05
Doug Walser
Pinnacle, a Halliburton Service Line

Quantifying the Impact of Induced Asymmetric Fracturing from Horizontal Development Wellbores; a Geostatistical Perspective

Summary

Sufficient production and fracture mapping evidence across North America was examined, and clearly demonstrates that groups of delineation and development wells often underperform when there is substantial production time (months or years) between the completions of the two wells. Though induced asymmetric fracturing has been attributed as a possible root cause of underperformance for a number of years, this study advanced the state of certainty of that conclusion to a higher level, and confirms the most frequent cause of incremental losses in reserves.

It is shown that the asymmetric fracturing into lower stress and lower pressure drained volumes can materially impact reserves and rate of recovery if the acreage position of a given project is substantial. It is demonstrated that the overall stimulated reservoir system permeability, the degree of permeability contrast between reservoir layers, and the degree of asymmetry are all factors that have an impact on the degree to which long-term time between completions affects recovery of hydrocarbons over and above simple volumetric depletion. Several scenarios for preventing extreme asymmetric fracturing are discussed.

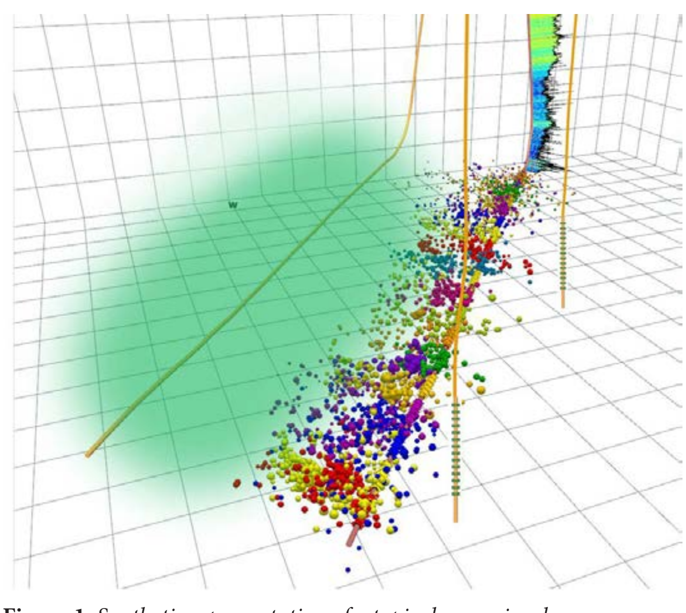

Figure 1. *Synthetic representation of a typical scenario where microseismic activity suggests asymmetric fracturing towards a lower pressure AD*

Introduction

The identification of the top technical drivers with the highest net present value (NPV) impact on large unconventional (ultra-low permeability) hydrocarbon extraction efforts have been studied by numerous authors. One of those key technical drivers relates to the mitigation of the negative effects of reduced productivity between offset laterals when there are long periods of time between adjacent completions[1-5].

Various operators have recognized that groups of delineation (parent) and development (child) horizontal lateral wells often underperform when the delineation wellbores produce substantial volumes prior to stimulation and completion of the of adjacent development wellbore(s). Initially, the industry reaction was to attribute the loss of reserves to inter-well communication across the two induced fracture networks, and focus on methods that might prevent that communication, such as adjusting lateral spacing and/or decreasing stimulation volumes pumped per unit of lateral length[6]. Reducing the stimulation volumes per unit of lateral length has an undesirable side effect of reducing the total exposed induced fracture surface area, which in turn can negatively impact the rates and volumes of reserves recovered. Increasing parallel lateral spacing to the degree that there is minimal or no communication between conductive fracture networks will most often leave a strip of unstimulated or understimulated reservoir volume in between the two wells. Contributing causes here are likely the simplification of fractures or fracture networks with increased distance normal to each wellbore, and/or uneven induced fracture lengths.

Comprehensive amalgamated microseismic records from North America over a 14-year period were examined. Results of this effort have provided confirmation that there is a statistically valid relationship between reduced proximate reservoir pressure and asymmetric induced fracturing trending toward the rock volume with the lower pressure. **Figure 1** is a synthetic summary graphic of this scenario. Numerous authors have demonstrated that asymmetric fracturing in the direction of a reduced pressure reservoir is likely if other Darcy and geomechanical parameters are held constant, but there has been some hesitation by operators to make fiscal decisions that assumed the validity of the theoretical geomechanics.

Method and Results

Two approaches were taken in the study. First, the amalgamated microseismic and microdeformation results from plays across North America were examined to statistically verify that the geomechanical assumptions were correct. Second, a series of computational reservoir simulations were undertaken[7-9] to assist in verification that the asymmetric fracturing logically resulted in production underperformance.

The fracture mapping data archives suggest that some unconventional horizontal plays typically experience asymmetric fracturing in the direction of lower-pressure drained area AD to a higher degree than other plays. The oil window of the Eagle Ford Shale and the Bakken/Three Forks are two examples where fracture asymmetry can be so extreme that induced fractures can cross multiple proximate parallel wellbores on their path to a lower pressure (and therefore lower stress) zone. Other plays can experience the asymmetry to a substantially lesser degree, suggesting that there may be fundamental physical realities that control the degree to which asymmetric fracturing can be a problem.

Mitigation of Asymmetric Fracturing

There is sufficient hard evidence that says asymmetric fracturing is the primary root cause of underperformance of a child well when a parent well has previously produced significant quantities of hydrocarbons and/or water. The fiscal impact of unmitigated asymmetric fracturing can be substantial. There is quite a bit of variation from play to play across North America, and some plays are virtually impossible to quantify due to the vulgarities of infrequent well testing and unreliable liquid hydrocarbon allocation. However, more reliable North Dakota data suggested underperformance by approximately 27%, and several gas plays across the US were in the 28 – 35% range. Recently, a number of operators in the Permian Basin (Delaware and Midland) cited ± 30% differentials between delineation and development laterals.

There are several well-known mitigation processes that have been employed[10-12], but none of them on their own are a catch-all:

a Minimize the time and production volumes between delineation and development by aggressively manipulating the D&C schedule (a number of larger majors and independents are actively practicing). This is a relatively capital-intensive process, but is extremely effective for up to approximately 75% of wellbores drilled on a given acreage position.

b Parent well re-pressurization fracs without proppant. These may not be quite as effective as many in the industry are claiming. High rate and no diversion are causing most fluids to exit casing in a limited percentage of the lateral. Not enough volume is pumped to re-pressurize original induced fractures and any reasonable percentage of adjacent matrix volume, or too much total original production from the parent well makes re-pressurization of original induced fractures and/or a measureable percentage of matrix unlikely.

c Parent well re-pressurization fracs with proppant. Very few of these are being performed in North America. Same scenario as (2) above, but with the added complication of sand fallout in pipe at low velocity is exaggerating the problem in (b) above. There may be sufficient evidence to suggest that mitigating the sand fallout with occasional viscous sweeps and/or washouts might result in more effective coverage along the lateral.

d Low-rate, high volume parent well re-pressurization. A number of operators across North America are experimenting with this technique. Though there is not enough hard public data to verify the relative degree of its effectiveness, there are signs that the practice could become more widespread over the next several years. The suggestion is that pumping these at lower rates over a long period of time could increase the percentage of fluid re-pressurizing a portion of matrix normal to existing induced and propped fractures.

e Combinations of low-rate, high volume parent well re-pressurization, followed by high-rate re-fracturing with proppant. Some very limited experimentation is ongoing across North America; no good public data verification is available. Presumably, there is a dual benefit – the prevention of asymmetric fracturing from the child or development well, and new incremental reserves produced from the parent well. Diversion is often involved. Again, like (c) above, mitigating the sand fallout with occasional viscous sweeps and/or washouts might result in more effective coverage along the lateral.

f "EOR", for cases where the primary hydrocarbon is a black oil with a bubble point Parent well repressurization with unprocessed field gas off a gathering line, followed by either immediate production, or by a refracturing operation. Like (d) and (e) above, there is potentially some good degree of matrix repressurization, leading to the dual benefit of both asymmetric fracturing prevention and lifting of incremental hydrocarbons (due to miscibility of the gas and lifting of localized static pressures back above the bubble point). If the repressurization effort is followed by a propped re-fracturing effort, then a third benefit could be realized – the incremental recovery of reserves that were not accessible by the original stimulation treatment. There are a number of large independents and major operators across North America that are actively experimenting with various manifestations of this.

Conclusions

Asymmetric fracturing into previously produced reservoir volumes is the primary root cause of underperformance of development wells. Though there are other contributing or casual causes, the interaction of development well induced fractures with partially drained reservoirs results in underperformance that can be fiscally material to companies with large acreage positions.

Underperformance can be mitigated via a number of proactive D&C and subsurface strategies.

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Biographical Sketch

Doug Walser has extensive (38 years) Permian Basin, Mid-continent, Appalachia, Rockies, and South Texas experience with Pinnacle, Dowell Schlumberger, The Western Company of North America, and BJ Services. He has specialized in the calibration of three-dimensional fracture modeling via a number of methods, including historical production transient analysis, and calibration by various fracture mapping processes. He has taught numerous seminars and short courses on subjects related to his fields of interest, including Mini-frac Evaluation, 3-D Pressure Matching, On-Location Stimulation QC, Fracturing Situations, Horizontal Completion Best Practices, Microseismicity, Fracture Mapping Techniques, and others. Most recently, he has focused on the application of integrated sensor diagnostics and the associated reservoir engineering of unconventional plays with high liquid hydrocarbon content. He has authored 40 papers & articles, and holds 7 patents in his areas of interest. He holds a BS in Natural Gas Engineering from Texas A&I University, and has worked for Pinnacle for the last 12 years.

Julie Kowan and See Hong Ong

Wellbore Stability: Special Considerations for the Marcellus Shale

Wellbore stability problems such as tight hole, pack-off, stuck pipe, inflow, and lost circulation are most commonly associated with conventional reservoirs but also occur in unconventional reservoirs. Prevention of wellbore instability saves time and money and can often be achieved by deriving a field-specific geomechanical model to inform the drilling recommendations. A basic geomechanical model consists of an understanding of the pore pressure, vertical stress, orientation, and magnitude of the horizontal stresses and the rock properties, though, of course, there are additional complexities that sometimes need to be considered.

We will use a generalized Marcellus Shale example to illustrate some special considerations regarding wellbore stability in unconventional reservoirs. First, as many areas of the Marcellus have fissile shale bedding, we investigate how much additional mud weight is required to prevent excessive wellbore collapse when weak bedding planes are present. We show that in some cases, the mud weight required to control shear failure is high enough to cause pre-existing fractures and faults to slip, which can cause additional mud to invade the formation. In such cases, if mud invasion cannot be prevented through the use of lost circulation materials, raising the mud weight can actually exacerbate the instability. We also examine the feasibility of underbalanced drilling and the effect of model uncertainties on our predictions.

Biographical Sketch

Julie Kowan is a Geomechanics Consultant with over 12 years experience helping operators drill safer, more cost-effective wells and plan field development by reducing non-productive time (NPT) due to wellbore instability and improving production. Julie has expertise in unconventional reservoirs, pore pressure prediction, stress constraint, wellbore stability, fracture permeability, and compaction. Prior to launching J. Kowan Consulting, LLC in June 2016, Julie was a Geomechanics Advisor at Baker Hughes from 2009 to 2016. Before being promoted to Advisor, Julie held several other technical geomechanics positions at Baker Hughes and GeoMechanics International from 2005 to 2009. Julie earned a Master of Science in Geology from Brown University and a Bachelor of Science in Geology from Rutgers University. She currently serves as the Vice President of the Boston Chapter of the SPWLA and was the Chapter Secretary from 2015 to 2017.

Thursday, November 9, 2017 | Session 4 | 2:35
Sandeep Mukherjee
Halliburton

Characterization of Fractures from Borehole Images

Summary

Characterization of fractures is an important aspect of formation evaluation. Fractures, when present could alter reservoir properties often to the extent where it influences exploration, completion, and development methods. Utilization of borehole images in this respect is a direct and intelligent technique in characterization of these fractures. This work presents a comprehensive review of fracture identification techniques from borehole images of two different kinds. Using these techniques detailed characterizations of both natural and drilling induced fractures are possible in a wide variety of reservoirs.

Introduction

The conventional workflows of identification of fractures and fracture networks rely heavily on seismic methods that involve elaborate acquisition, intense processing, and detailed knowledge of local geology. Though these methods provide a bigger perspective of the fracture systems in a reservoir scale, it often lacks the resolution of characterizing at a well level. Furthermore, the processing and interpretation of the acquired seismic measurements are time intensive and often fall short of generating actionable decisions for a well in progress.

Borehole image logs are a reliable way to identy and classify fractures in single well scale. These open hole logs could be acquired through a variety of conveyance methods (wireline, drill pipe, tractors), both in vertical and inclined wellbores, in post-drilling as well as in logging-while-drilling scenarios.

In both conventional and unconventional environments where reservoir drainage is contingent on the presence of fracture systems, these images provide a fast, reliable, and replicable approach of characterization that facilitates completion decisions, identifying landing targets, as well as for broad scale reservoir characterization.

Methods

This work utilizes resistivity and acoustic images of wellbores to classify and characterize fractures. This work only considers wireline image logs that were acquired post drilling. However the identification and characterization techniques that were used here, could be universally applied to all kinds of borehole images, irrespective of conveyance methods.

The resistivity images shown in this work are high resolution azimuthal micro-resistivity measurements of the wellbore obtained from a pad based image tool (**Figure 1**). The tool used in this in study is an extended range microimager that has six caliper mounted, independently articulated pads. The tool generates a total of 150 independent resistivity measurements at a given depth with a vertical resolution of 0.2 inches (Moherek et. al. 2016). These resisvity measurements are then processed to render a resistivity image around the borehole. The image has a 62% borehole coverage in a 8 inch wellbore.

The acoustic image is also a high resolution measurement that has a complete 360 degree representation of the wellbore. This image is from a circumferential acoustic scanning tool (**Figure 2**), and is constructed from ultrasonic measurements, with a vertical resolution of 0.4 inches and azimuthal resolution of 2 degrees.

Both these measurements are orders of magnitude superior from traditional seismic methods of detecting fractures.

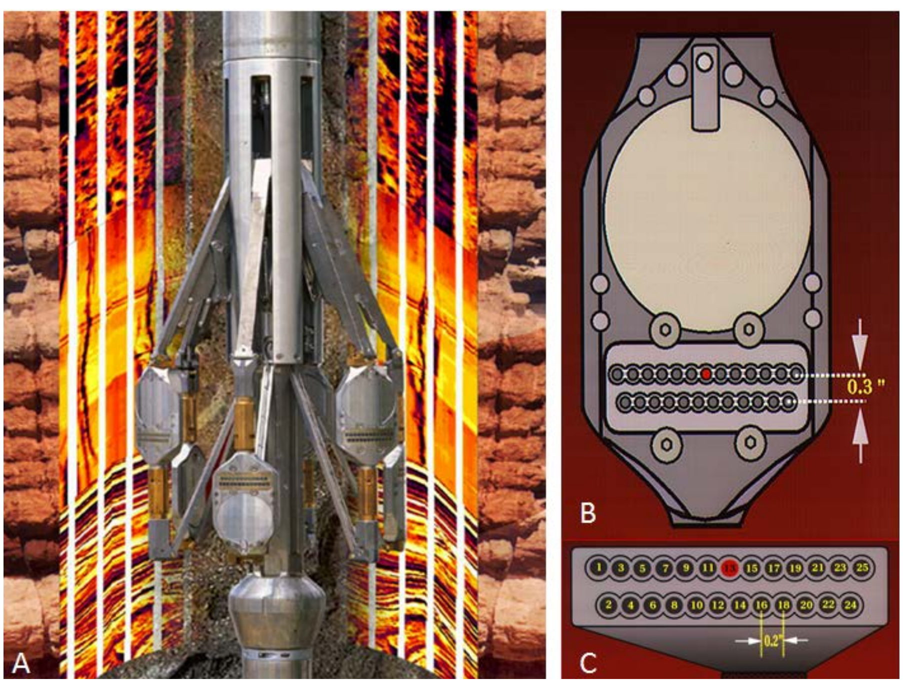

Figure 1: *A) Figure showing an extended range micro-resistivity imaging tool and the resistivity image it generates from the individual button measurements. B) Schematic of an individual extended-range micro-imaging pad and C) the arrangement of the 25 buttons in each of these pads (adopted and modified from Moherek et. al. 2016).*

Figure 2: *A) Figure showing an ultrasonic imaging tool and the amplitude image it generates from the circumferential acoustic scanning measurements. B) Magnified view of the mud cell built into the tool which measures drilling mud properties that are utilized to correct the images for attenuation of ultrasonic waves C) Magnified view of the rotating scanning head.*

Interpretation Philosophy

In classifying fractures from these acoustic and the resistivity images, this work employs an approach that is based on the morphology of planar and linear features detected in the wellbore. This approach is believed to be simple, straightforward, and could easily be adopted by any geologic workflow.

Based on this approach, the fractures are classified under four major categories as below.

- Natural Open Fractures
- Natural Healed Fractures
- Drilling Induced Fractures
- Borehole Breakouts

Based on this broad classification scheme, several other subcategories of fractures could be identified, where applicable and deemed necessary by an interpreter

The following two examples show the morphological character of a natural open fracture (**Figure 3**) and a natural healed fracture (**Figure 4**). Though both are naturally occurring, these

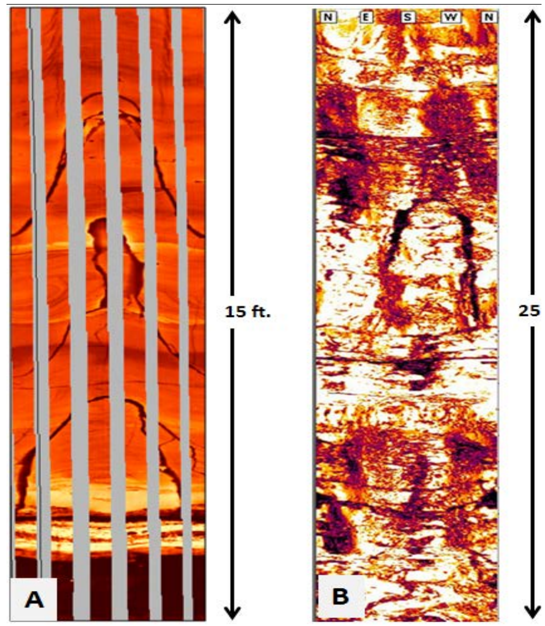

Figure 3: *Figure showing natural open fractures as observed in, A) high resolution azimuthal micro-resistivityimages in a conductive mud environment, B) Ultrasonic image. The two examples are from two different wellbore.*

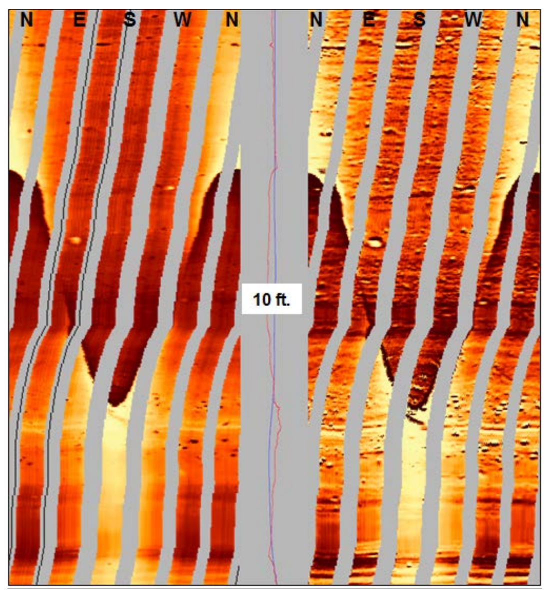

Figure 4: *Figure showing natural healed fractures as observed in a high resolution azimuthal micro-resistivityimages in a conductive mud environment.*

images could very well identify the openness of the apertures, and hence aid in granularity of classification. It is also quite remarkable to observe the aperture on the open fractures (**Figure 3**) which are no more than two inches in this case are clearly visible. The conventional techniques of fracture identification through seismic methods are not able to provide such granularity and resolution.

Applications

Characterization of fractures from borehole images has a wide variety of applications. The resolution of these images

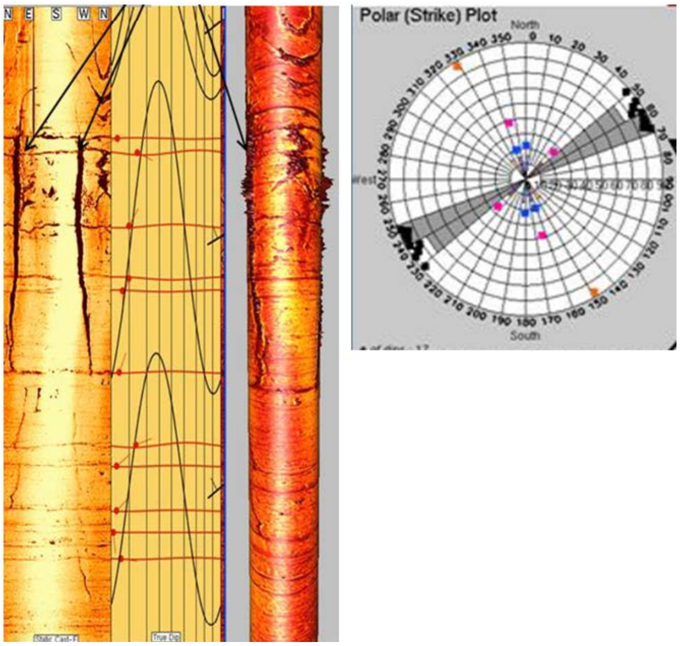

Figure 5: *Figure showing borehole stress analysis of a typical wellbore drilled in overbalanced condition. The ultrasonic image log on the left shows a drilling induced fracture with strike azimuth orientation of NE-SE. The stereonet plot on the right shows strike azimuth orientations of all the drilling induced fractures in the wellbore (in black).The mean strike azimuth orientation of the drilling induced fractures of N60E-S60W indicates the orientation of maximum horizontal stress of this wellbore.*

allows for characterization of fractures even at an individual fracture level. Apart from conventional applications of fracture identifications in reservoir characterization, the two most common application of this kind of characterization are determining orientation of borehole stress, where the wellbore has been drilled in over/under balanced conditions, and calculating fracture induced porosity of the reservoir, by quantifying the apertures of natural open fractures (Luthi & Souhaite, 1990). The fracture intensity curves determined from quantifying fracture population by units of depth, in a multi well setting, allows the users a straightforward measure of mechanical stratigraphy. All this information could further be used for designing completions, identifying lateral targets, and for broader intelligence of field development.

Conclusions

The methods presented here in this review are direct, have proven and established processing workflows, and requires less input from elaborate historical experiences. The interpretations of the characterization here become available in a significantly faster timeframe and could be included in making completions decisions. These interpretations are based on consistent characterization schemes and could be correlated across wells. The superior resolution of image logs also allows characterization from a single well and even at an individual fracture level.

In this age and time, where operators are looking for fast, reliable techniques of reservoir characterization that generates actionable ideas for time sensitive completion decisions, the methods like the ones presented here become of paramount importance. The high resolution yet direct and straightforward approach of this method makes it superior to other available methods for single well and individual feature scale evaluation of fractures. ■

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Biographical Sketch

Sandeep Mukherjee is the Geology Advisor and Technical Team lead for Halliburton's Formation and Reservoir Solutions (FRS) Group in Houston. Sandeep began his career as a Geologist with Schlumberger in 2006 where he was primarily focused on the utilization of advanced techniques in the image interpretation realm to provide sophisticated geologic solutions. Through the years in Schlumberger Sandeep managed several responsibilities including that of Geology Team Lead for Schlumberger Data Services of the Permian Basin, and Geology Domain Champion of the North American and Middle Eastern Geomarkets. Sandeep Joined Halliburton in 2014, and has been leading the FRS team of the South-eastern United States. In his present position Sandeep advises Halliburton's varied clientele in designing the right approach towards advanced, reservoir specific, geologic and petrophysical characterization. Sandeep also acts as a bridge between the FRS group, the customer and WP-BD organization in streamlining and customizing advanced measurements and high end answer products for precise representation of reservoir heterogeneity.

His broader research interests encompass interpretation of borehole images, constructing geologic reservoir models, analysis of fracture systems, sequence stratigraphy, heterogeneous rock analysis, and characterizing carbonate reservoirs. He earned a Bachelor and a Masters in Geology from University of Calcutta, India in 1998, and 2000 respectively and a Masters in Geology from University of Minnesota in 2006. He is a member of AAPG, SPE, & SPWLA.

Thursday, November 9, 2017 | Session 4 | 3:10
Sergey Kotov,
S. Stolyarov, U. Prasad and F. Walles
Baker Hughes, a GE company

Lateral Characterization and Fracture Optimization Solution with Case Studies

Market surveys (Bloomberg news, March 2016) show that approximately 70% of unconventional wells do not meet their expected production targets, and that approximately 30% of all perforation clusters are not contributing to hydrocarbon production. A review of 125 production logs across multiple shale plays (Welling & Company, SPE 144326) indicate that the best producing wells have at least 80% contributing clusters and the poorest wells have only 30% contributing clusters.

Conversely, ongoing work by leading industry operators has shown a step change in significantly improved hydrocarbon productivity within shorter lateral lengths. This has been attributed to improved targeting using advanced completion approaches with the integration of appropriate data sets, including 3D seismic, and reservoir characterization (specific vertical and lateral logs and core data).

Recent advances in rig-site equipment, technology, and fast data processing has resulted in an improved ability to analyze well cutting's elemental compositions and mineralogy, to better determine mineral facies, and the brittleness (or ductility) contrasts spatially within the length of the laterals. This together with offset acoustic or seismic data can give an indication of stresses and formation breakdown characteristics. The gas hydrocarbons concentrations (C1-C5, & up to C9) from gas data can indicate near-borehole fracture intensity index, reservoir fluid type, productive versus non-productive zones, potential fluid contacts, and reservoir connectivity.

The addition of advanced deep shear wave imaging technology, applied to open or cased hole logging environments, can detect shear impedance boundaries that do not intersect the borehole, i.e., geohazards such as folds, faults, and natural fractures. Combining accompanying acoustic attributes can also be used to develop or complement elastic properties and in-situ stress characteristics determinations.

Integration of these attributes can improve identification of optimal reservoir property zones with desired hydrocarbon contents, maturity, facies, brittleness, and fracability. This drives improved custom cluster and stage designs for more homogenous distribution of highly complex fractures with the right conductivity along the laterals.

If the stress or brittleness contrast is beyond a threshold limit, suitable diverters can also be utilized and multiple stages can be combined into "super-stages". This allows better distribution of proppants and fluid systems to maximize individual cluster contributions.

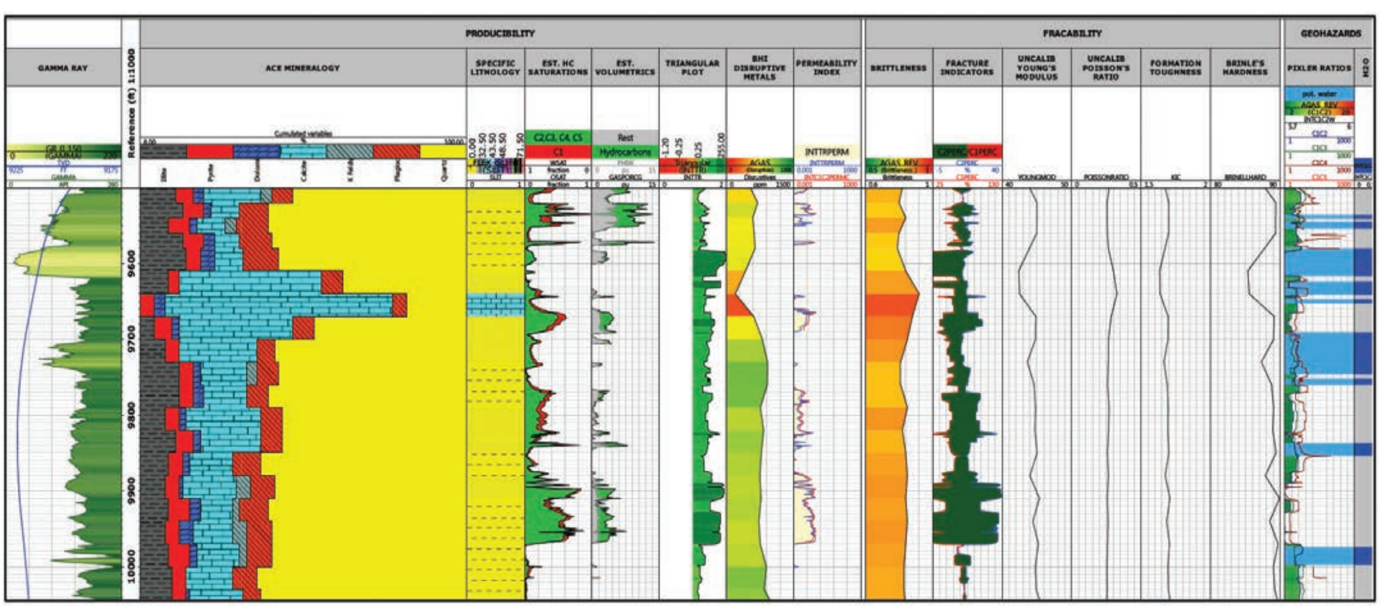


Figure 1. *A summary plot of lateral characterization from cuttings and mud-log analysis.*

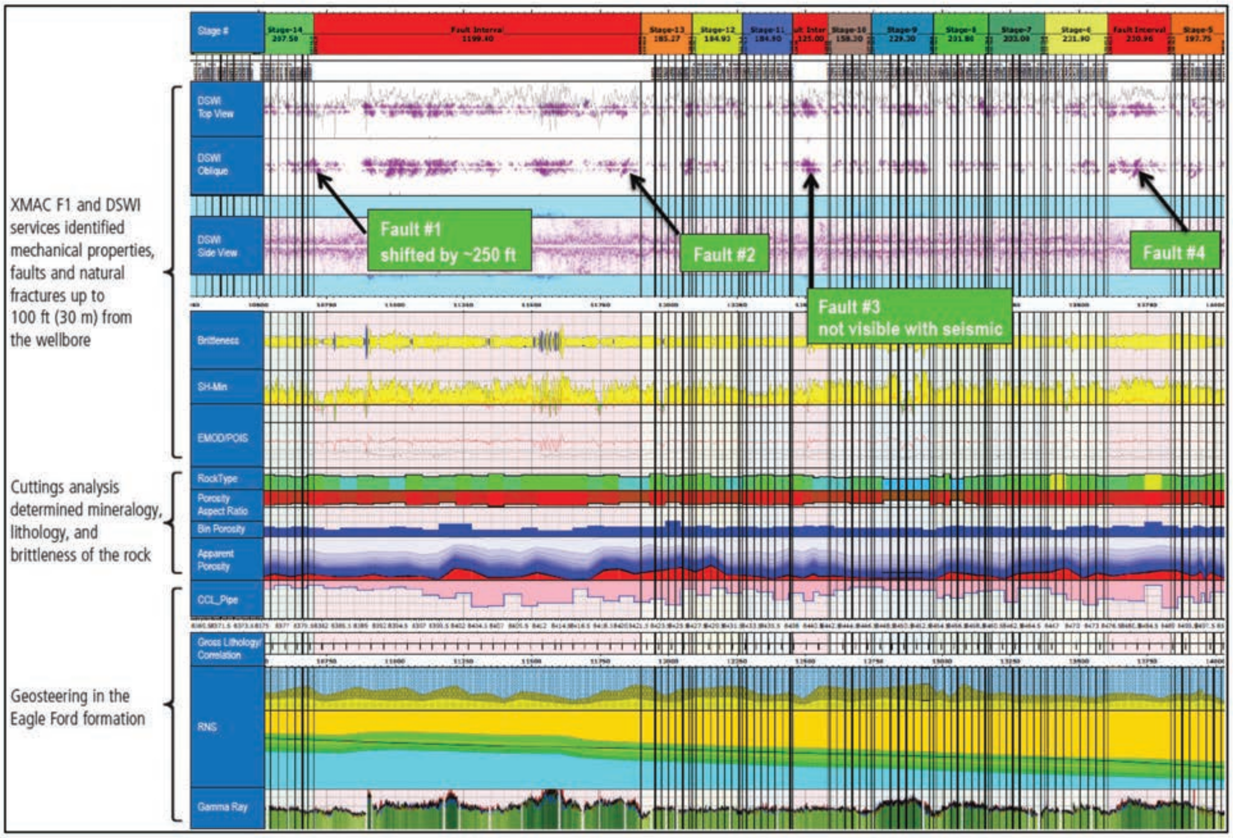


Figure 2. *Illustration of the application of deep shear wave imaging technology to detect geo-hazards or faults for avoidance and use of fracture intensity index beyond the borehole vicinity.*

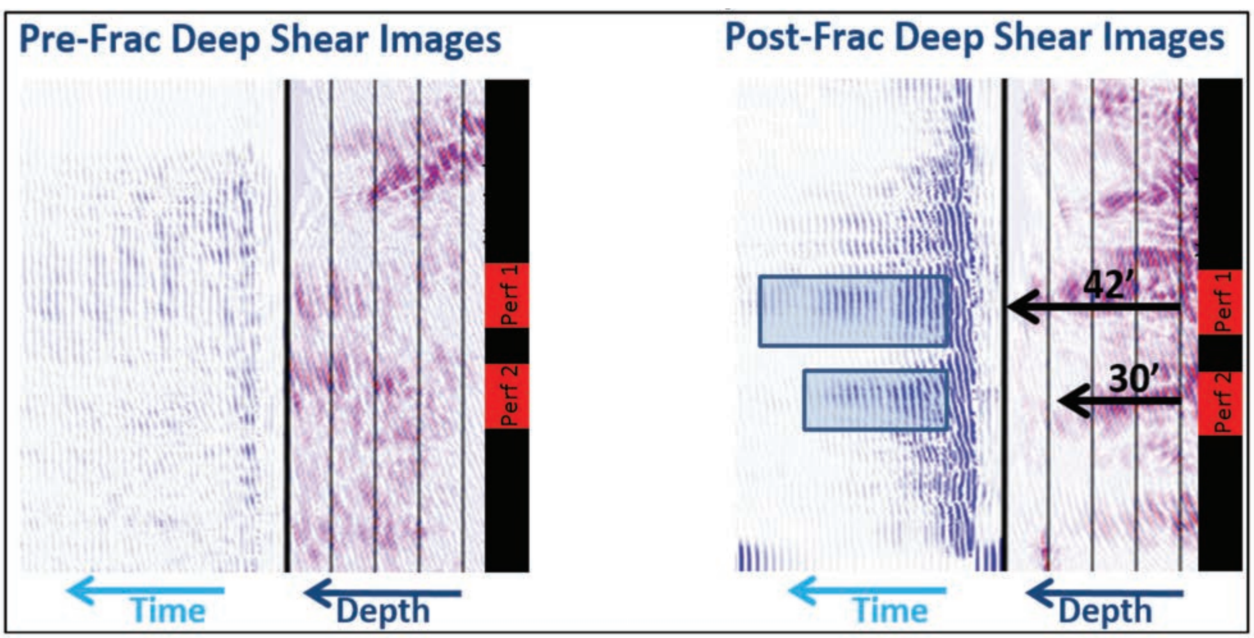


Figure 3. *Imaging frac job (height & length) in a vertical well complementary to micro seismic.*

Figure 4. *An example showing how the technology used has resulted in $2.5 MM savings.*

Biographical Sketch

Sergey Kotov is the Manager of Integrated Technology, Enterprise Technology at Baker Hughes, a GE Company. Kotov has 22 years of oil and gas industry global experience and extensive knowledge of technology, application, and integrated cross-product line solutions. Sergey has broad experience in engineering (primarily specializing in production enhancement), product line management, and business development.

Kotov started his career in Russia, participating in all aspects of pumping operations in most of the major oil and gas basins from the South to the Arctic Circle. As an application engineer at BJ Services Technology Research Center, he participated in the development and optimization of new stimulation technologies. As a senior stimulation specialist, Kotov worked in North Africa. He was involved in many stimulation projects around the world. In recent years Kotov has specialized in unconventional stimulation as a Senior Stimulation Advisor/ Stimulation Manager for Unconventional Resources, and as a Global Product Line Manager for Unconventional Fracturing, providing technical expertise and leadership globally. Currently Kotov is leading the Baker Hughes Completion Design and Production Performance Optimization Solution in Unconventional Reservoirs (Formation Evaluation focused on stage placement and risk mitigation). Kotov is also leading the Integrated Initiatives related to production rejuvenation to maximize value from the existing assets in unconventional reservoirs.

He is an active member of the SPE. He has participated in numerous industry events as a speaker and a panelist. Kotov is as instructor for the "Unconventional Completions and Fracturing" SPE course, he is a co-author of Baker Hughes' Recommended Practices / Data-Driven Solutions for Shale Gas/Oil Analysis and Development, a co-author and instructor for Baker Hughes' Shale Academy, and a co-author of "Unconventional Oil and Gas Resources: Exploration and Development" book CRC press, 2016, 2017 Winner-American Publishers Awards for Professional and Scholarly Excellence in Engineering and Technology. Projects include Best EOR Technology 2015 World Oil Awards Finalist, and 2016 World Oil Awards Winner.

Kotov holds an MS in petroleum engineering/oil and gas geology (Russia), he also earned an honors MA in linguistics (Russia).

Notes

Poster Presentations

November 8 – 9, 2017

Southwestern Energy
Spring, Texas

Ming Liu and Haiying Huang,
Georgia Institute of Technology

A Poroelastic Solution of Rigid Sphere Indentation into a Compressible Half-Space

The problem of a rigid sphere indenting a porous semi-infinite domain could be of great interest to drilling and geophysical exploration. Within the framework of Biot theory, we develop a poroelastic solution for the problem using Laplace and Hankel transforms. The current solution improves from the solution of Agbezuge and Deresiewicz (1976), where the problem formulation only assumes that the half-space is incompressible, and the numerical results of the stress, pore pressure and displacement fields are given only on the contact surface. In this study, the compressibility of the pore fluid and the solid skeleton is taken into account, and a methodology is developed to determine the full stress, pore pressure and displacement fields inside the half-space. Moreover, the accuracy and efficiency of the numerical evaluations are enhanced utilizing improved numerical schemes. Finally, effects of the compressibility of the constituents in the porous medium on the evolution of the poroelastic fields with time are investigated.

Biographical Sketch

Ming Liu earned his bachelor and master degrees in petroleum engineering from China University of Petroleum, Beijing. He is currently a PhD student in the Geosystem Group at the Georgia Institute of Technology. He has been working on numerical and analytical analyses of the indentation problems and their applications in improving drilling efficiency.

Anusarn Sangnimnuan, Jiawei Li and Kan Wu
Texas A&M University

Development of an Efficient Coupled Fluid Flow and Geomechanics Model to Predict Stress Evolution in Unconventional Reservoirs with Complex Fracture Geometry

Stress changes associated with reservoir depletion is often observed in the field. Stress evolution within and surrounding drainage areas can greatly affect further reservoir developments, such as completion of infill wells and refracturing. Previous studies mainly focus on bi-wing planar fracture geometry, which limits possibility of investigating stress evolution due to complex fracture geometry. In this paper, we have developed a novel and efficient coupled fluid flow and geomechanics model with Embedding Discrete Fracture Model (EDFM) to characterize stress evolution associated with depletion in unconventional reservoirs with complex fracture geometry as well as complex natural fractures. Coupled geomechanics and fluid-flow was developed based on well-known fixed-stress split, which is unconditionally stable and computationally efficient to simulate how stress changes during reservoir depletion. EDFM was coupled to the model to gain capability of simulating complex fracture geometries using structured grids. The model was validated against classical Terzaghi's and Mandel's problems. Local grid refinement was used as a benchmark when comparing results from EDFM for fractures with 0° and 45° angles of inclination. Following that, the model was used to analyze stress distribution and reorientation in reservoirs with three different fracture geometries, planar (90° angle of inclination), 60° inclination, and non-planar fracture geometries. As the pressure decreases, reservoir stresses tend to change anisotropically depending on depletion area. The principal stress parallel to the initial fracture reduces faster than the orthogonal one as a function of time. Decrease rate of principal stresses is distinct for different shapes of depleted areas created by different fracture geometries. Rectangular shape produced by the planar fracture geometry yields largest stress reorientation area for a variety of differential stresses (difference of two horizontal principal stresses). Squared shape produced by non-planar fracture geometry only yields stress reorientation for low differential stress. The results indicate that created fracture geometry has a significant effect on stress distribution and reorientation induced by depletion. Complex natural fractures result in more complex depleted shape, which leads to different reorientation angles. This concludes the importance of natural fracture when simulating stress evolution in unconventional reservoirs. To the best of our knowledge, it is the first time to develop a coupled fluid flow and geomechanics model incorporated EDFM to efficiently calculate stress evolution in reservoirs with complex fracture geometry. Characterization of stress evolution will provide critical guidelines for optimization of completion designs and further reservoir development. ■

Biographical Sketch

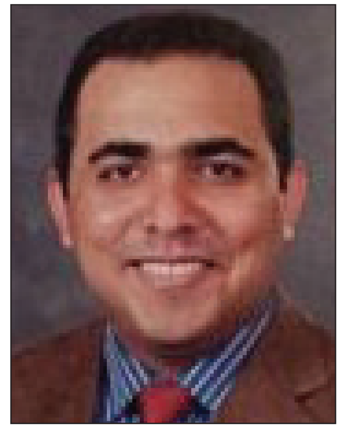
Anusarn Sangnimnuan is a PhD candidate in the Harold Vance Department of Petroleum Engineering at Texas A&M University. His research is focused on developing a coupled geomechanics with fluid-flow to investigate stress evolution due to depletion effect. His work also involves coupling the model with EDFM to predict stress evolution in complex fracture geometries. Anusarn holds BS and MS degrees in Mechanical Engineering from Chulalongkorn University (Thailand) and The University of Michigan (Ann Arbor), respectively. He is a member of SPE.

Arash Shadravan and Behrouz Haghgouyan
Texas A&M University

Geomechanical Cement Sheath Finite Element Modeling to Achieve Enhanced Zonal Isolation

We used Abaqus and Comsol finite element package for formation-cement-casing 3D modeling under operational scenarios in which the pressure and temperature inevitably change. We modeled the wellbore using a hole inside a cube. Abaqus mesh is refined close to the wellbore where internal pressure is applied. An 8-node brick, trilinear displacement, trilinear pore pressure (C3D8P) is used as element type. Two yield criteria are used for predicting the failure: Drucker-Prager and Mohr-Coulomb. Plastic strains and Mises stresses are plotted for three different values of applied internal pressure: 50 MPa, 80 MPa and 120 MPa. The Drucker–Prager yield criterion is a pressure-dependent model. This criterion determines whether a material has failed or undergone plastic yielding or not. The Drucker–Prager yield criterion has been applied to rock, concrete, polymers, foams, and other pressure-dependent materials. In this paper, we used this criterion to investigate the failure in a wellbore system. The FE models were calibrated with the analytical model and then the sensitivity analysis was executed to detect various modes of cement failures. We show the 3D map of total displacement isosurfaces inside tubing and the cement layer. It can be drawn that we should expect higher displacement at the center of the tubing and the cement, and consequently higher chance of fatigue in these areas. We also demonstrate the stress map on a system of cemented casing. The distribution of stresses show that at the interface of the tubing and the cement layer, there is a slight decrease in overall stress which helps the integrity of cement layer at the vicinity of the tubing/cement interface. ■

Biographical Sketch



Arash Shadravan has been working on his PhD at Texas A&M University since 2015. He worked at pressure pumping technology center of Baker Hughes as a R&D engineer III in Tomball. He interned with OXY in Bakersfield, with Schlumberger and Superior Energy in Houston and with GlobalData in New York City. He was a research assistant during his MS in petroleum engineering at Texas A&M University (TAMU) in College Station and a teaching assistant in a semester abroad at TAMU in Qatar.

During his PhD studies, he worked on projects related to Geomechanical finite element modeling, fracture mechanics of ductile and brittle materials, corrosion and characterization techniques such as SEM, XRD, EDS, WDS, SIMS and NMR.

Arash has been a member of Society of Petroleum Engineers (SPE) since 2006. SPE Gulf Coast Section selected him to represent the SPE Young Professionals in the 2015 Emerging Leaders Alliance in Washington, D.C. He has been a reviewer for SPE Drilling and Completion journal and other Elsevier petroleum engineering journals. Arash co-authored 35 technical papers, which gained over 300 citations.

Edith Sotelo Gamboa and Richard L. Gibson
Texas A&M University

Fracture Compliance: Relationship with Fracture Conductivity and Effect On Wave Propagation

After hydraulically fracturing an unconventional reservoir, conductivity of the created network becomes the fundamental fracture property controlling fluid flow. Thus to estimate hydraulic fracture conductivity is essential for a reliable production forecast. On the other hand, fracture compliance is a parameter used to incorporate fracture behavior in the modeling of seismic wave propagation and, in principle, it can be related to fracture conductivity. We present a mathematical model that relates fracture compliance and conductivity and we also show how variations in fracture compliance affects scattering of incident waves.

Fracture conductivity depends on its aperture, which in turn is a function of the in-situ effective normal stress. To prop open fractures and enhance permeability, proppant is commonly injected during stimulation. A mathematical model based on Hertz contact theory that relates closure of fracture aperture versus in-situ normal stress is used to estimate propped fracture conductivity. Then, to estimate normal compliance, the partial derivative of closure respect to normal stress is taken and the relationship between compliance and conductivity is established. Results from this model show that conductivity increases with increasing fracture compliance and with the number of proppant layers.

To understand the effect of compliance on wave scattering, transmission and reflection coefficients are calculated applying the linear slip model for a incident plane wave striking a fracture idealized as a non welded interface separating two half spaces. Results show that the amplitude of the scattered wave depends not only on compliance but also in the frequency content of the incident wave. In general, the higher the compliance and the frequency content of the incident wave, the higher the amplitude of the scattered wave. Future work will investigate how to use scattered and transmitted waves to invert for fracture compliance. We also want to validate our mathematical model relating conductivity and compliance with experimental work and finally be able to provide a reliable estimate of fracture conductivity.

Biographical Sketch

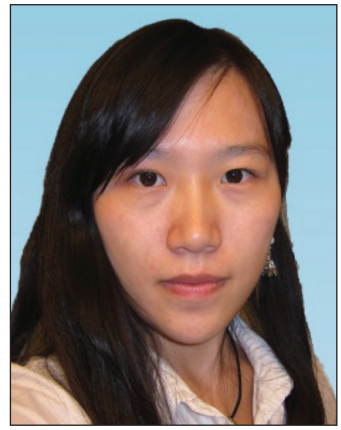
Edith Sotelo Gamboa is a PhD student in Geophysics at Texas A&M University, working under the supervision of Dr. R. Gibson. Her academic background includes a MS in Petroleum Eng. (Texas A&M University) and a BS in Chem. Eng. (Universidad Nacional de ingenieria, Peru). She also worked as a logging engineer for Schlumberger. Her research interests include fracture characterization and modeling, numerical modeling of wave propagation, microseismicity and inverse modeling.

Guangjian Xu, Judith Chester and Fred Chester
Center for Tectonophysics, Department of Geology and Geophysics
Texas A&M University

Developing a Mechanical Stratigraphic Model of the Eagle Ford Formation

A quantitative mechanical stratigraphic model of the Eagle Ford Formation is developed to characterize geomechanical properties for individual and composite lithologic units to assist in the reservoir model development, hydraulic fracture treatment design, and mechanics-based numerical simulations of fracture network development. The model is developed from a detailed lithologic characterization of outcrop and core successions of the Eagle Ford Formation, petrographic and mineralogic analyses of a suite of representative samples, and experimental rock deformation of the representative samples. Selected carbonate-rich Eagle Ford samples from outcrops in West Texas and subsurface core in South Texas present the variations in rock types, composition, texture, sedimentary structures, thermal maturity, and digenetic features. Shale elastic and inelastic mechanical properties and mode of failure (e.g., fracture modes) as a function of confining pressure and temperature are determined in triaxial compression tests. The elastic properties, rock ultimate strength, yield strength, and inferred cohesion of Eagle Ford Shale are controlled by grain size and mineralogy. The organic-rich mudstones are significantly more ductile compared to grain-supported facies (e.g., packstones), yielding at lower stress and up to 1% strain prior to fracture. The geomechanical properties determined for key individual lithologic properties are used to quantify mechanical properties of the entire Eagle Ford Formation based on detailed lithologic logs with a resolution of decimeter scale. The experimental/lithology based static Young's modulus upscaled to a resolution of the sonic log shows good agreements with geophysical log-based dynamic Young's modulus from boreholes on the same outcrop and core.

Biographical Sketch



Guangjian Xu is a Ph.D. student studying at the Center for Tectonophysics at Texas A&M University. Prior to enrolling at Texas A&M, she obtained a bachelor's degree in Geochemistry at University of Science and Technology of China and a master's degree in Geological Sciences from UT-Austin. Guangjian's research interest lies in geomechanics related problems and its application in unconventional shale gas exploration and production.

Ishank Gupta
Carl Sondergeld and Chandra Rai, Mewbourne School of Petroleum and Geological Engineering,
The University of Oklahoma
Ronny Hofmann, Shell International Exploration and Production Inc

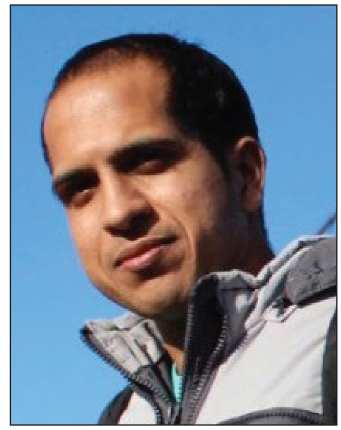
Water Weakening: Case Study from Marcellus, Woodford and Eagle Ford

Hydraulic fracturing is the completion method of choice to maximize productivity and increase profits in unconventional resource plays. Standard laboratory protocols for measuring rock strength, Young's modulus and Poisson's ratio commonly do not account for moisture content in the rocks, yet these parameters are critical in fracture designs.

The process of water weakening is particularly complicated in shales due to the combination of Total Organic Carbon (TOC), swelling clays and reactive minerals like silica and calcite. A study was carried out to determine the effects of spontaneous fluid imbibition (brine and dodecane) on Young's modulus and hardness in shale. The measurements were made using a nanoindenter on shale samples from the Marcellus, Woodford, and Eagle Ford.

A key objective is to compare weakening effects of brine versus dodecane. It was found that irrespective of the shale wettability, brine led to a greater reduction in Young's modulus (45% reduction in Marcellus, 25% in Woodford, and 12% in Eagle Ford) than dodecane (25% reduction in Marcellus, 17% in Woodford, and 4% in Eagle Ford). Clay stabilizing solutions like KCl brine had limited success in reducing the water weakening effect. Carles and Lapointe (2005) suggested that the key to water weakening effect is the access to the grains. The access to the pores and the grains is strongly controlled by wettability. Since, polar solvents like water cause greatest weakening, results show that strongly water wet Marcellus had greatest weakening (45%), followed by mixed wet Woodford (25%) and lastly, oil wet Eagle Ford (12%).

Biographical Sketch



Ishank Gupta earned a BS degree in petroleum engineering from University of Petroleum and Energy Studies (India) in 2009. He worked as a reservoir engineer in Schlumberger from 2010 to 2015. He mainly worked in the areas of reservoir characterization, field development and enhanced oil recovery. He recently completed his MS in petroleum engineering from University of Oklahoma in 2017. He worked on data analytics, unconventional shale petrophysics and rock physics. He is currently doing his PhD in University of Oklahoma.

Alex Vachaparampil and Ahmad Ghassemi
Reservoir Geomechanics and Seismicity Research Group
The University of Oklahoma

Failure Characteristics of Three Shales under True-Triaxial Compression

Popular methods for measurement and prediction of rock strength and brittleness from triaxial testing (using the Mohr-Coulomb criterion) incorporates only the effects of the maximum (σ1) and minimum principal stresses (σ3), with no significance attributed to the intermediate principal stress (σ2). Consequently, the fracture behavior of rock is not well understood under in-situ conditions, where the two horizontal stresses are distinct. In this study, true-triaxial stresses (independent stresses in all three directions) are recreated and applied over shale specimens in a specialized laboratory setting to study the fracture behavior of three different oil & gas shales (Mancos, Barnett & Eagleford) under in-situ conditions. The strength of shale is observed to increase as a function of both horizontal confining stresses (contrary to assumptions inherent in the common Mohr-Coulomb criterion). Alternative failure criteria for shale under true-triaxial stresses are described, and methods to obtain true-triaxial strength parameters from conventional triaxial tests are also outlined. Rock brittleness (assessed from stress-strain curves) increases sharply when the contrast between the two horizontal stresses (σ2 & σ3) is increased, and corresponding differences are observed in the fracture tortuosity as well as the grain structure adjacent to the fault plane. Increasing the contrast between the two confining stresses (σ2 & σ3) is seen to alter the rock failure mechanism, manifesting as an increase in rock strength and brittleness. ■

Biographical Sketch

Alex M. Vachaparampil is a doctoral researcher at the Mewbourne School of Petroleum and Geological Engineering at the University of Oklahoma. He works on characterizing the rock mechanical and petrophysical properties of reservoir rock for the oil and gas industry. He received his Bachelors in Mechanical Engineering from the National Institute of Technology, Calicut, India. He started his career working on the development of subsea well completion equipment with FMC Technologies for various deep-water fields worldwide. To gain stronger insight into reservoir development, he went on to graduate school and earned his MS degree in petroleum engineering at the University of Oklahoma, where he developed a keen interest for the petrophysical and geomechanical properties of rocks, and their influence on wellbore and reservoir behavior.

He is now pursuing his doctoral degree under the guidance of Dr. Ahmad Ghassemi. His research focuses on developing rock mechanical characterization techniques to guide drilling and well completions practices. He hopes to build a career in the industry as a rock physicist, and to apply rock mechanics principles towards well completion optimization.

Some of his research projects involve the characterization of oil shale anisotropy, determination of poroelastic coefficients for low permeability rock, quantification of rock brittleness, and true-triaxial failure criteria for shale.

Zhi Ye and Ahmad Ghassemi
Reservoir Geomechanics and Seismicity Research Group,
The University of Oklahoma

Mechanical Properties and Permeability Evolution of Shale Fractures under Triaxial Loading

Shear slip caused by increased pore pressure due to injection has been considered as a major mechanism for permeability enhancement of unconventional hydrocarbon reservoirs. Reactivated pre-existing fractures around a hydraulic fracture slip and dilate and can also propagation in the shear and tensile modes creating secondary cracks resulting in increased permeability. Control and optimization of shear stimulation can be achieved by studying how fluid flows through fractures as the stresses (shear and normal) change and how fracture permeability evolves with slip. Such data can then be used in numerical models that consider shear slip and time-dependent unpropped conductivity loss to help design stimulation jobs that are more effective potentially with less proppants, and water (reduced stages and re-frac). Therefore, fracture's mechanical properties (shear strength, friction and stiffness, etc.) and fluid flow behavior (stress-dependent permeability and permeability evolution with fracture slip) are needed. In this work, we presents the results of triaxial shear tests on shale fractures to characterize their mechanical properties and to investigate fracture's stress-dependent permeability, as well as permeability evolution with fracture slip and dilation. The mechanical properties can be combined with fluid flow behavior of shale fractures for numerical simulations to model the process of shear stimulation in shale reservoirs. ■

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Ye, Z. and Ghasssemi, A. 2016. Deformation Properties of Saw-Cut Fractures in Barnett, Mancos and Pierre Shales. In proceeeding of 50th US Rock Mechanics/Geomechanics Symposium, Houston, Texas, 26-29 June, 2016.

Ye, Z., Janis, M., Ghassemi, A., et. al. 2017. Laboratory Investigation of Fluid Flow and Permeability Evolution through Shale Fractures. In proceeeding of the Unconventional Resources Technology Conference, Austin, Texas, USA, 24-26 July, 2017.

Some results:

1. Mechanical properties

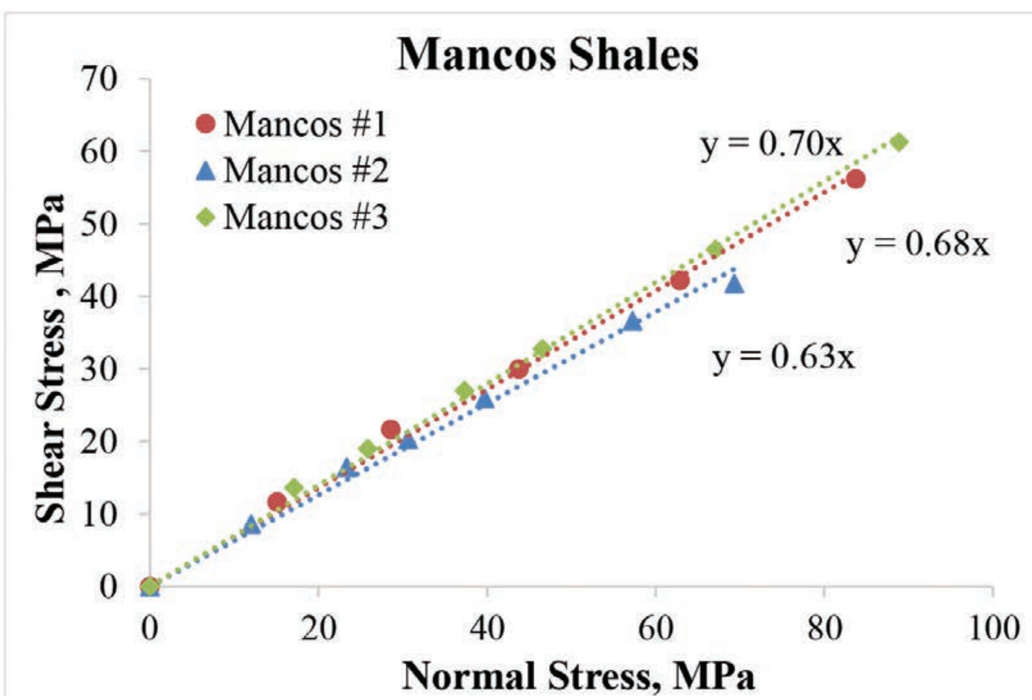


Figure 1. *Shear strength envelopes of three Mancos fractures using Mohr-Coulomb model.*

2. Stress-dependent permeability

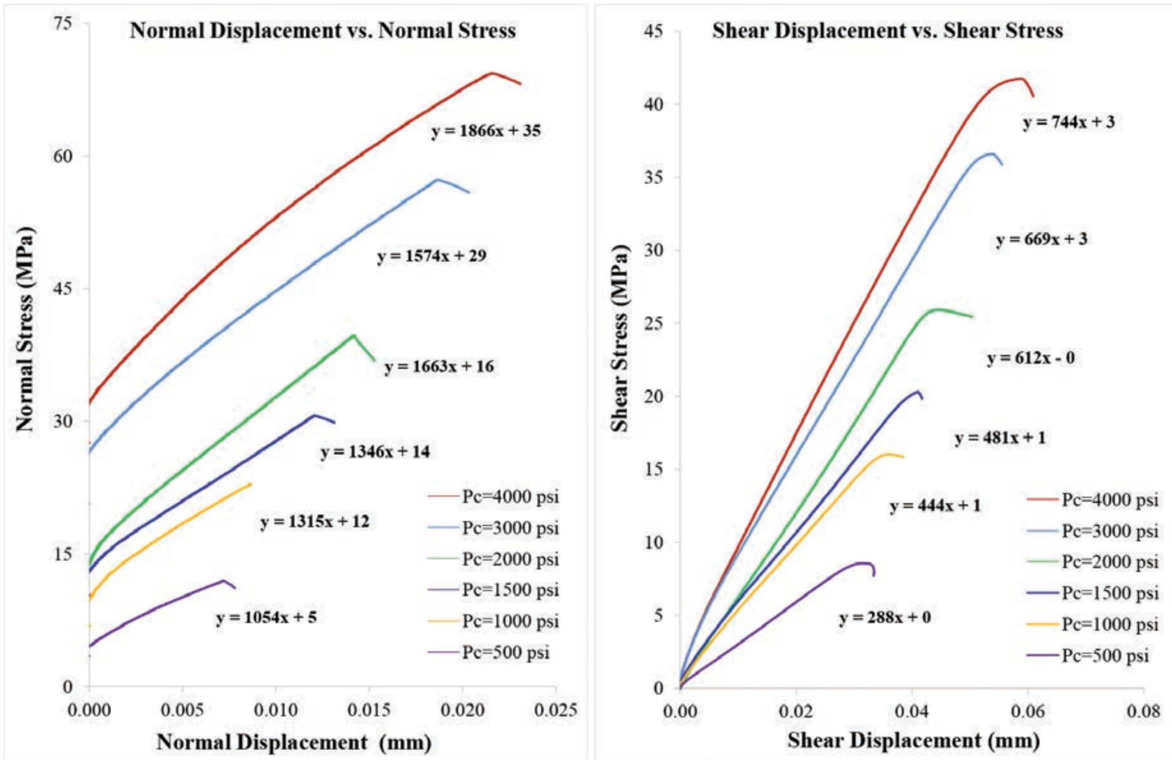
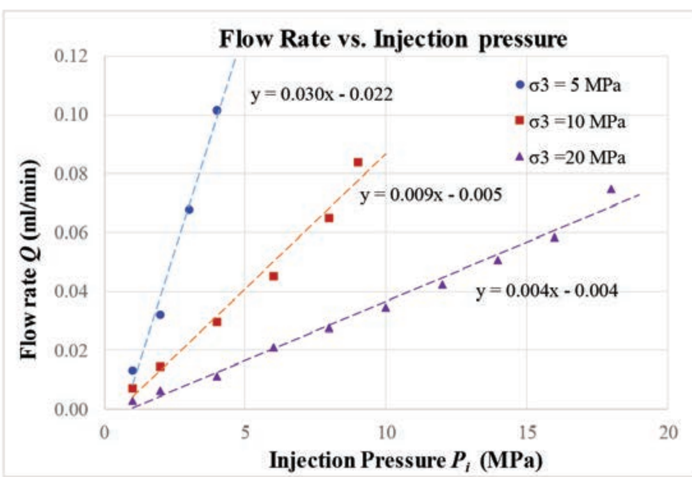


Figure 2. *Plots of stress vs. displacement on fracture plane: the slopes are normal stiffness and shear stiffness respectively.*



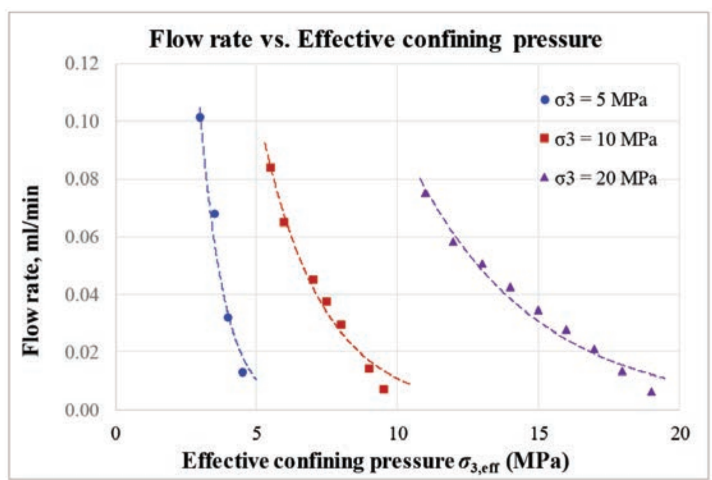
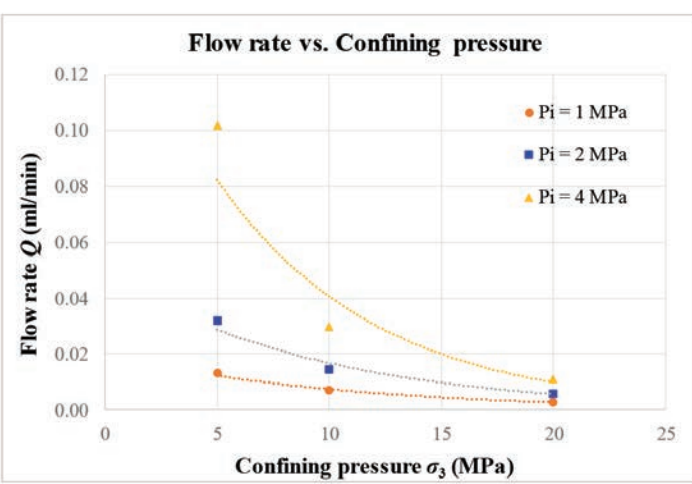


Figure 3. *Stress-dependent permeability: Linear relationship between flow rate and injection pressure, however, exponential relationships can be observed between flow rate and confining pressure, as well as flow rate and effective confining pressure.*



3. Permeability evolution with fracture slip and dilation

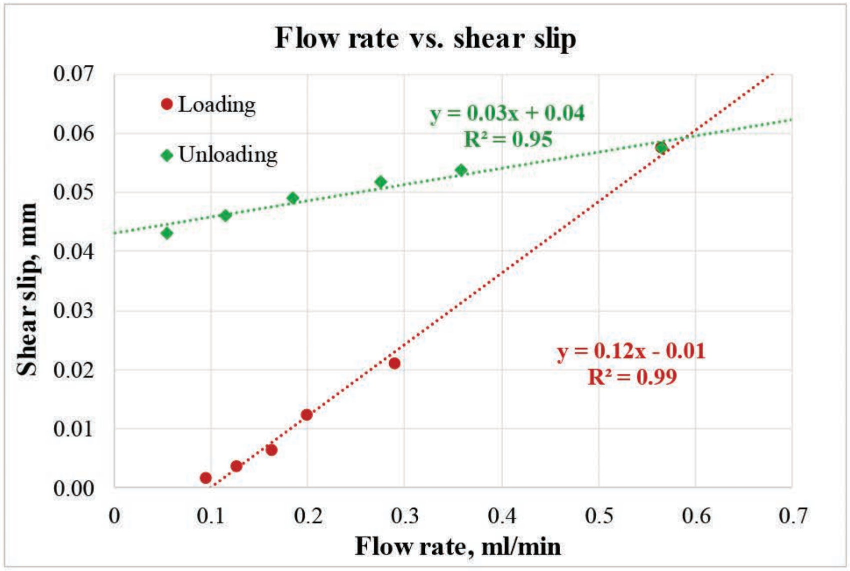


Figure 4. *Injection-driven shear test on induced tensile fracture of Eagle Ford Shale*

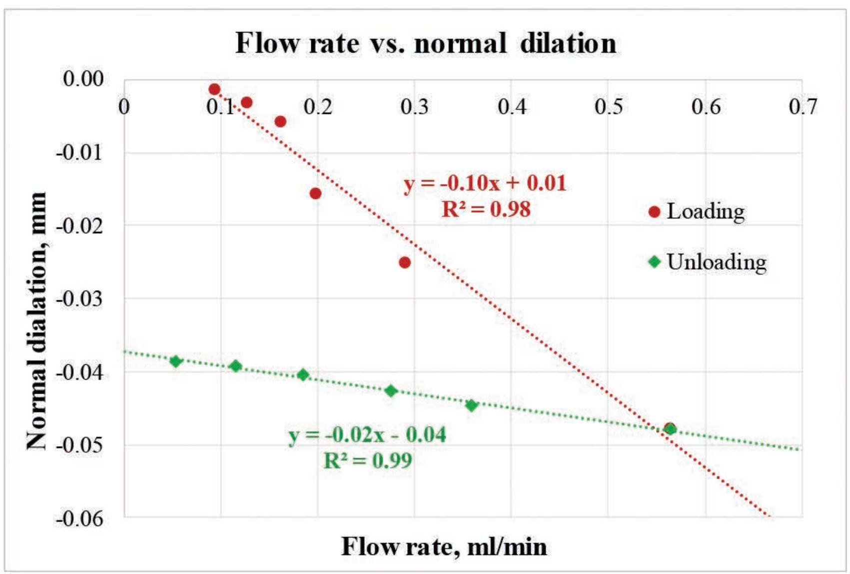
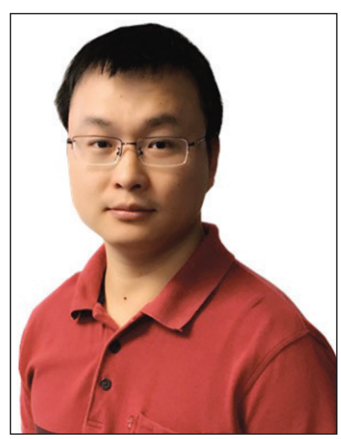


Figure 5. *Flow rate change with fracture shear slip and normal dilation.*

Biographical Sketch

Zhi Ye is a PhD Student of Petroleum and Geological Engineering at The University of Oklahoma. Until summer 2014 he was a research scholar for Wider Windows JIP program at The University of Texas at Austin. He holds a BSc Degree in mechanical engineering from Yangtze University, China; and he earned a D Eng. in oil and gas well engineering from China University of Petroleum-Beijing. He conducts research in the areas of reservoir geomechanics, pore pressure estimation and drilling performance evaluation. His recent research project focuses on experimental and numerical modeling study on rock joint deformation and fluid flow. The goal of this project is investigating the fundamental mechanisms of permeability evolution during shear stimulation for the developments of unconventional shale and geothermal reservoirs.



Matthew J. Ramos,
D.N. Espinoza and C. Torres-Verdín,
Department of Petroleum and Geosystems Engineering, The University of Texas at Austin,
K.T Spikes, Jackson School of Geosciences, The University of Texas at Austin,
S.E. Laubach, Bureau of Economic Geology, The University of Texas at Austin

Stress-Dependent Dynamic-Static Transforms of Anisotropic Mancos Shale

Shale mechanical behavior varies widely within and between formations, with layering-induced anisotropic rock properties complicating drilling, formation evaluation, and hydraulic fracturing. Core scale characterization of shale mechanical properties is valuable for understanding rock behavior in the laboratory, however measurement frequency and strain magnitude often limit upscaling to the wellbore and reservoir scales. The development of stress dependent dynamic-static transforms of shales provides a means for upscaling laboratory derived anisotropic rock properties, as well as understanding how these relationships may vary with changing stresses and induced damage. In this study, we conduct simultaneous triaxial stress tests and ultrasonic wave propagation monitoring to quantify static and dynamic stiffness anisotropy in Mancos Shale. Measurements of Mancos Shale plugs taken perpendicular, parallel, and at 45° to bedding allow for determination of the 5 independent stiffness parameters necessary to describe this pseudo transversely isotropic material, from which anisotropic quasi-static and dynamic Young's moduli and Poisson's ratios are calculated. Relationships between static and dynamic anisotropic effective moduli are presented as dynamic-static transforms, where the directional and stress dependences of stiffness are evaluated.

Results show anisotropic and nonlinear stress, strain, and damage dependences of static and dynamic moduli. In general, increases in confining stress caused increased Young's moduli for all plug orientations, but only impact Poisson's ratios corresponding to loading parallel to bedding. Increases in deviatoric stress cause increased Young's moduli until roughly 70% of peak stress, and increasing static Poisson's ratio in all loading orientations, with little change in dynamic values. Comparison between naturally fractured and intact Mancos samples show increased ratios of dynamic to static Young's moduli for fractured samples at the same confining stress, where intact samples have ratios between 2:1 to 4:1 and naturally fractured samples exhibit ratios between 4:1 and 8:1. Naturally fractured samples exhibit lower static and dynamic Young's moduli, which increase with deviatoric stress until failure, whereas intact samples decrease beyond 70% of peak stress. Overall, higher ratios of dynamic to static moduli are likely related to lower mechanical competence (due to natural fractures), and increasing ratios with increasing deviatoric stress is linked to stress-induced damage during testing.

X-ray microtomography imaging was utilized to evaluate natural fracturing and correlate mechanical behavior with microstructural changes after deviatoric loading to failure. Image analysis shows interaction between stress-induced fracturing with bedding planes and pre-existing natural fractures. Understanding the potential linkages between the dynamic and static responses of naturally fractured and intact anisotropic rocks in the laboratory provide opportunities to upscale stress-strain behavior to the wellbore environment and better utilize dipole sonic and time-lapse well logs to decrease mechanical uncertainty of unconventional reservoirs.

Biographical Sketch

Matthew Ramos is currently pursuing a PhD in Geological Sciences in the Jackson School of Geosciences at The University of Texas at Austin. His research pertains to the laboratory characterization of fractured shales through triaxial stress testing and ultrasonic wave propagation. His research and education are funded through a Statoil Graduate Research Fellowship for the 2014-2018 academic years. He holds a MS in Petroleum Engineering from UT Austin, a MS in Civil Engineering from Tufts University, and BAs in Geology and Physics from Bowdoin College.

Bram Komaromi
University of Calgary
Dr. Per Kent Pedersen Department of Geoscience, University of Calgary
Dr. Paul MacKay, Shale Petroleum Ltd.

Diagenetic Evolution of the Cherry Valley Member of the Oatka Creek Formation, Marcellus Subgroup, New York

Facies-controlled fracture stratigraphy in organic-rich unconventional petroleum systems: Implications from outcrop analysis, Turonian Second White Specks Formation, southwest Alberta, Bram Komaromi and Dr. Per Kent Pedersen Department of Geoscience, University of Calgary and Dr. Paul MacKay, Shale Petroleum Ltd.

Detailed analysis of natural fracturing style and intensity in unconventional tight reservoirs is a crucial step in their geomechanical characterization as natural fractures can provide essential permeability for hydrocarbons, impact hydraulically induced fractures, and influence wellbore integrity. Comprehensive subsurface fracture characterization can be challenging since high-resolution subsurface fracture data is limited in its extent, but outcrops provide useful 3D subsurface reservoir analogs. Outcrops of the Second White Specks Formation along Highwood River in southwest Alberta were divided into three major lithofacies: 1) black organic-rich mudstone; 2) interbedded finely laminated siltstones and mudstones; and 3) the Jumping Pound Sandstone. Fracture parameters were recorded for each facies interval at several structurally distinct outcrops using the scanline and circular estimator methods. Results were used to examine the differences in natural fracture characteristics between sedimentary facies at several structural positions. Lithofacies 1 contains conjugate shear fractures that occur at intensities of 4.2–7.4 fractures per meter with average heights of 0.41–0.86 meters. Lithofacies 2 contain extensional fractures that occur at higher intensities of 24-30 fractures per meter with much shorter average heights of 0.04–0.12 meters, the latter being related to the finely interlaminated siltstone-mudstone fabric. Lithofacies 3 contains extensional fractures that occur at intensities of 5.2–8.5 fractures per meter with average heights of 0.44–0.76 meters. Elevated fluid pressures from oil generation from Type II kerogen within the two mudstone facies likely increased pore pressure to the point that promoted the formation of extensional fractures compared to the shear fractures that occur in the overlying Jumping Pound Sandstone. The observed relationships between sedimentary facies and natural fracture stratigraphy were consistent across all structural positions, suggesting that sedimentary facies, and the resultant geomechanical stratigraphy, have a strong control on fracture stratigraphy. Results from this study suggest the anisotropy and heterogeneity of sedimentary facies characteristics have strong influences on natural fractures in the Second White Specks Formation outcrops along the Highwood River. The observed relationships and distribution of natural fractures provide valuable insight into the influence of sedimentary facies on natural fractures in unconventional reservoir targets.

Biographical Sketch

Bram Komaromi is a PhD student in the Department of Geoscience at the University of Calgary. His research is focused on understanding the role and influence of sedimentary facies characteristics on natural fracture networks in unconventional type reservoirs. Bram completed his undergraduate in 2014, graduating with First Class Honors in Geology from the University of Calgary. During the final year of his undergraduate, Bram completed an undergraduate thesis under the supervision of Dr. Per K. Pedersen which inspired him to continue his research as a graduate student. Bram was a member of the 2015 University of Calgary IBA team, which placed second in the Canada Region Competition. Bram is currently a Visiting Scientist at the Geological Survey of Canada where he is conducting research on fluid inclusions within natural fracture fills. Most recently, Bram completed an internship for Nexen where he worked on natural fracture characterization and discrete fracture network modelling in the Horn River Basin.

Ismot Jahan
John Castagna, and Michael Murphy
University of Houston

Characterization of Faults Using Seismic Attributes From 3D Seismic Data in the Bakken Formation

The success of horizontal drilling in unconventional oil and gas reservoirs mostly depends on optimal well placement which creates a large number of closely spaced fractures and thus achieves maximum reservoir contact area. Hence, it requires the operator to factor the dominant trend of the natural faults and fractures. Intersecting and crossing conjugate normal faults, ranging from microscale and mesoscale to macroscale are commonly observed in many oil fields. At smaller scales, such faults are a major factor in the development of permeability anisotropy. So, it is highly important to understand the distribution of such faulting in unconventional reservoirs such as the Bakken Formation where permeability is one of the main keys to successful production.

A variety of dip adaptive geometric attributes is generated such as curvature, coherence, chaos, variance and phase Laplacian as a function of frequency. Principal component analysis (PCA) is used to produce a composite fault attribute which shows the principal orthogonal projections where the data has the largest variance. Generally, the first few principal components are sufficient to account for the large majority of the variance in the data. The composite attribute was then post-processed with a sharpening algorithm and a noise removing chaos filter. Volumetric true dip and strike were then measured on the PCA fault attribute.

The PCA fault attribute shows significantly different, and geologically more plausible, three-dimensional fault distributions than conventional seismic attributes, such as curvature. Two distinct fault trends approximately 40°-50° NE-SW and 50°-60° NW-SE are observed in the Bakken Formation. Seismically derived fault orientations correlate to borehole image log data in the wells. We observed conjugate fault geometries in the seismic horizon and an apparent flip in dip direction of faults along strike. Those faults may result in widening of the faulted area and localized thinning of the rock sequence where the faults intersect, and could potentially enhance permeability along fault strike.

Biographical Sketch

Ismot Jahan is currently a graduate student and pursuing her Ph.D. in geophysics at the University of Houston. Previously, she received a BS (2008) and an MS (2010) from University of Dhaka in applied physics. Her current research interests include quantitative interpretation, seismic data conditioning, seismic attribute analysis, seismic modeling, and reservoir characterization. Her long-term career goal is pursuing her career as a geophysicist in oil and gas industry.

Ali Razaei
University of Houston

Effect of Pore Pressure Depletion on Horizontal Stresses and Propagation of New Fractures during Refracturing Process

Refracturing of a horizontal well is a method to restore the productivity of the well in unconventional reservoirs after the expected production decline. Placement of new fractures in a system that has been already depleted poses new challenges for operators. These challenges are due to the altered stress zones resulting from the expected pore volume depletion and corresponding pressure decline. In this study, effect of pore pressure depletion on horizontal stresses, and refracturing propagation issues in a horizontal well are studied.

A fully coupled poroelastic displacement discontinuity model has been developed to study refrac propagation in horizontal wells. Displacement discontinuity is a powerful numerical method for studying hydraulic fracture problems. The model is verified using available analytical solutions for undrained and drained fracture behavior. Maximum horizontal stress criterion is used to account for the fracture propagation. Several cases are analyzed using the model. For each set, scenarios that increase the chance of successful refracturing are suggested.

Results of this study show that the pore pressure depletion is the key factor in defining extent and severity of stress redistribution zones in the reservoir. The effect of pore pressure is shown to be asymmetric in horizontal wells between two parallel fractures. It was observed that stress anisotropy between two parallel fractures decreases in the area between two parallel fractures and increases between the tips of two fractures. After a certain time, stress anisotropy in area between two fractures becomes negative which means that the horizontal stresses orientation is reversed in that area. Placing any fracture in the stress-reversed area causes an unwanted change in direction of fracture propagation and eventually an intersection between new and old fractures. It is also observed that the new fracture tends to propagate toward the nearest old fracture. This tendency increases as pore pressure depletion becomes greater, increasing risk of refracturing failure. A sensitivity analysis is performed on the factors such as: legacy fractures spacing, fracture pressure, distance between new fracture and old fractures, etc. to investigate the best possible treatment plan for each scenario.

Biographical Sketch

Ali Rezaei is a PhD candidate in petroleum engineering at the University of Houston. Currently, his research is focused on development a fully coupled non-planar hydraulic fracture simulator. He is the author and co-author of several technical papers and a book chapter on hydraulic fracturing. His research interest areas are poroelasticity, hydraulic fracturing simulation, and computational geomechanics. Ali has a master degree in petroleum engineering from Texas Tech University. He has completed several projects on hydraulic fracturing as a member of Texas Tech hydraulic fracturing group. Additionally, he initiated TTU ARMA student chapter at Texas Tech University, and served as the president for Texas Tech SPWA student chapter.

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