Applied Geoscience Conference

November 6-7, 2019

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Applied Geomechanics: Through the Life Cycle of the Field

Day 1 AM Session 1	Accessing Targets Faster with Safer Wellbores
Lunch Keynote	**Robert W. Zimmerman**, *Imperial College, London*
Day 1 PM Session 2	Optimizing Completion Footprint and Stimulation Designs
Day 2 AM Session 3	Post-stimulation Diagnostics and Monitoring
Lunch Keynote	**Tony Settari**, *CGG Services (Canada) Inc.*
Day 2 PM Session 4	Extending the Life of the Field: Production, Refracturing, and EOR

University Poster Session represented by: Georgia Tech, Oklahoma State University, Purdue University, The University of Oklahoma, The University of Texas, University of Calgary, University of Houston, Utah State University

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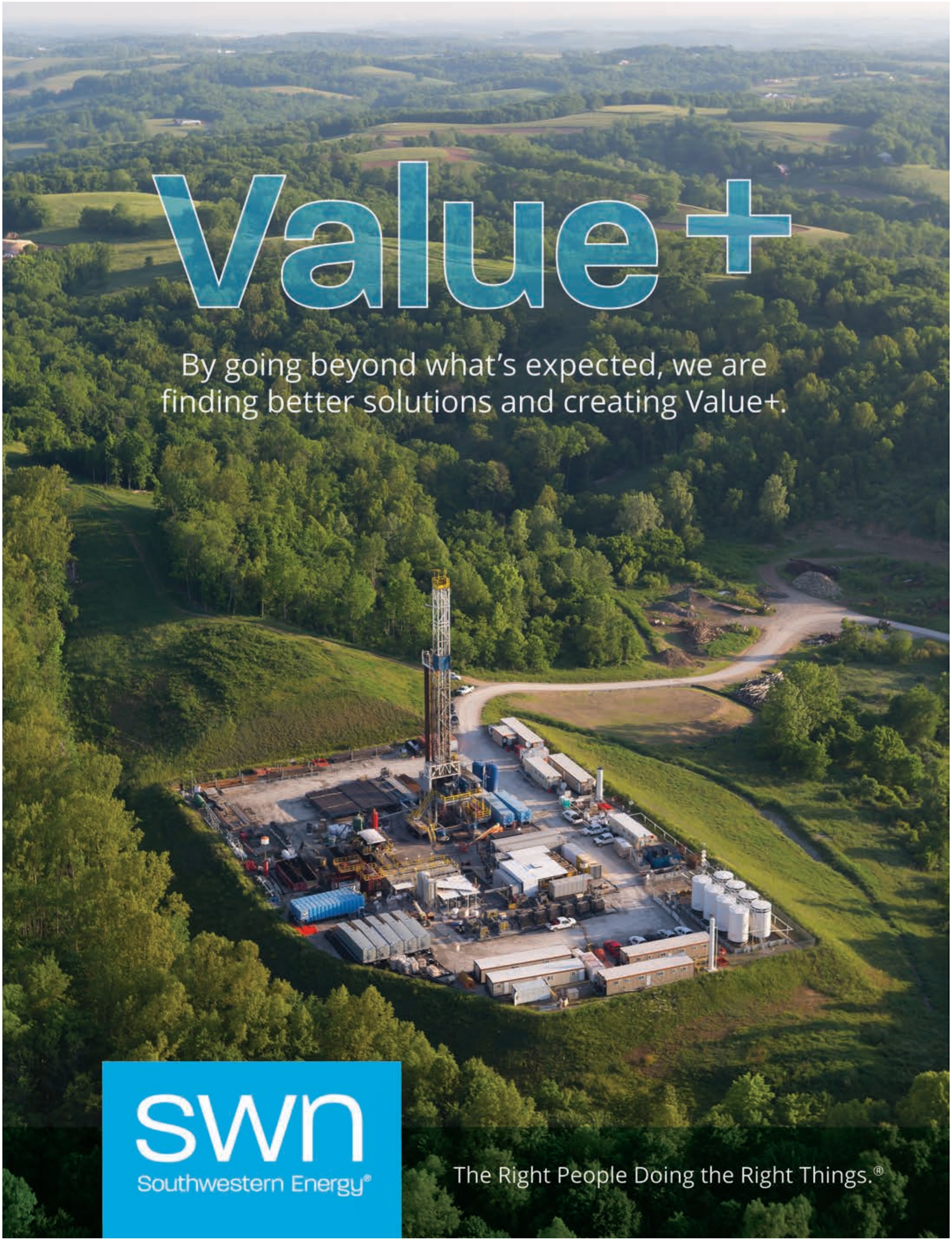
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Best Poster Award Ballot

Important Instructions:

Please cast your vote for the one poster you feel is most deserving of the conference **Best Poster Award** and return this ballot to the Registration Desk no later than 12:00 Noon on November 7.

Vote here	Student Name	University	Poster Topic
☐	**Ming Lui**	Georgia Institute of Technology	Poroelastic Indentation – Feasibility of a New Testing Method for Tight Rocks
☐	**Jingyao Meng**	Oklahoma State University	Geomechanical Characteristics of the Prospective CO_2 Sinks and Seals, Eastern Gulf of Mexico
☐	**Wenging Wang**	Purdue University	Heterogeneous Stress State in the Crystalline Crust Beneath the Western Canadian Sedimentary Basin: Observations from Borehole Image Logs to 2.4 km
☐	**Zhi Ye**	The University of Oklahoma	The Role of Pre-Existing Fractures in Shale Reservoir Stimulation
☐	**Juan Acosta**	The University of Oklahoma	Study of Creep Behavior in Barnett Shale Using Nano-Indentation
☐	**Mehdi Teymouri**	The University of Texas	Coupled Hydro-Mechanical Analyses and Modeling for Reliable Characterization of Fracture Propagation in Anisotropic and Spatially Heterogeneous Formations
☐	**Shivam Agrawal**	The University of Texas	Effect of Rock Heterogeneity at Different Length Scales on Fracture Geometry
☐	**Marco Venieri**	University of Calgary	Predicting Reservoir Potential of Unconventional Shale Plays from Wireline Logs: A Correlation Between Compositional and Geomechanical Properties of the Devonian Duvernay Formation, Alberta, Canada
☐	**Abdullah Bilal**	University of Houston	Predicting Static Data, Using Dynamic Properties and Quantitative Sample Characterization
☐	**Suresh Dande**	University of Houston	Elastic Properties of Propped and Unpropped Eagle Ford Shale and 3D-printed Fractured Rock Models
☐	**Rongrong Lin**	University of Houston	A Damped Dynamic Finite Difference Approach for Modeling Static Stress-Strain Fields
☐	**Sabyasachi Prakash**	University of Houston	Analysis of Unconsolidated Sands' Yielding Behavior Under Unloading Conditions

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Proceedings Volume

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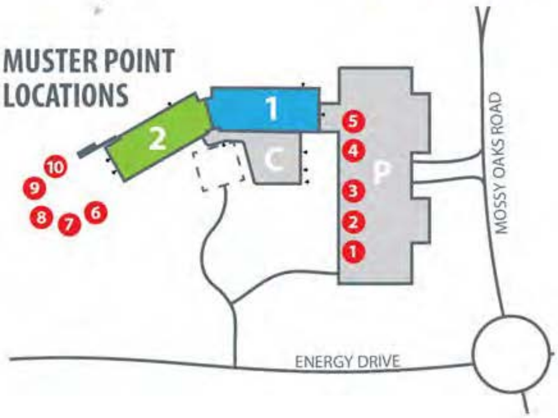

- Always dial 911 in the event of a medical emergency; bomb threat; crime in progress; intruder; fire; terrorist activity; and chemical, biological, or radiological events.
- When exiting affected floors during an emergency, use the evacuation routes designated on the Egress Maps. Once you have exited the building, proceed in an orderly fashion to closest Muster Area.
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MUSTER POINT LEGEND

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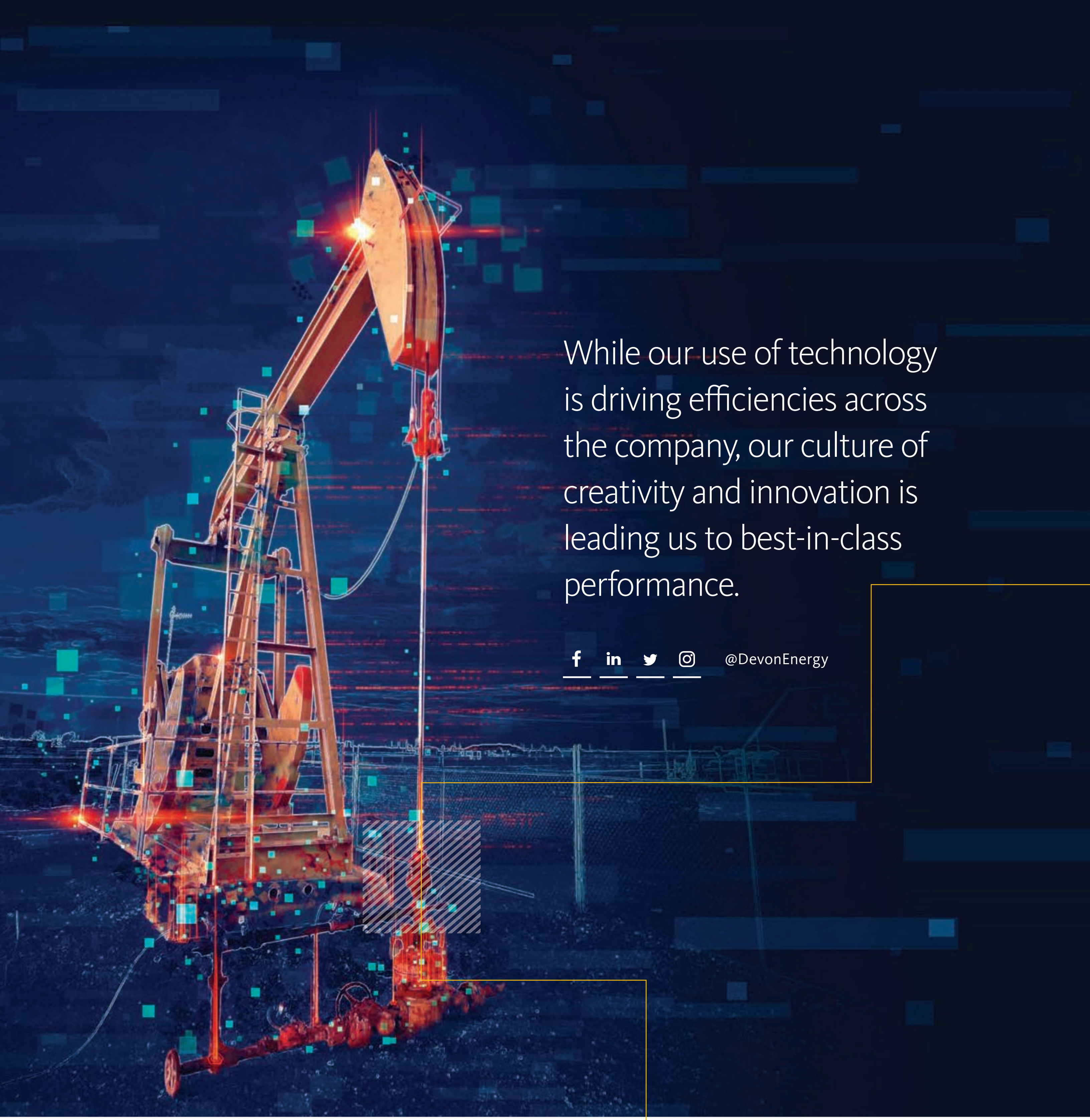
Muster Point	1	2	3	4	5	6	7	8	9	10



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Applied Geoscience Conference

November 6-7, 2019

Oral Presentations – Wednesday, November 6, 2019

7:00	**Registration and Coffee**	
8:00 - 8:10	**Welcome and Opening Remarks:** Jon Blickwede, *HGS President*; Umesh Prasad, *Baker Hughes;* SWN representative	
	Session 1: Accessing Target Faster with Safer Wellbores **Chairs:** Lauren Cassel, *Completion Imaging Analysis*; Mark Herkommer, *Excellence Logging*	
8:10 - 8:45	Advanced Seismic Inversion for Geomechanics Applications in Unconventional Reservoirs	**Colin Sayers**, *Schlumberger*
8:45 - 9:20	Lost-in-hole Diagnostics and Mitigation	**Agus Tjengdrawira**, Julie Kowan, and Namsu Park, *Baker Hughes*
9:20 - 9:40	**Coffee, Posters, Exhibits**	
9:40 - 10:15	Laboratory Modelling of Salt Deformation and its Correlation with Drilling Mechanics of Record Hybrid Drill Bit Runs in the GOM	**Ashabikash Roy Chowdhury**, Umesh Prasad and Ryckman Callais, *Baker Hughes*
10:15 - 10:50	Novel Pore Pressure Prediction Technique for Unconventional Reservoirs	**Vivek Swami**, Robert Raney, Adriana Perez, *CGG*; David P. Yale *Geomechanics Consulting*
10:55 - 11:55	**Open Floor Discussion & Posters**	
11:55 - 1:00	**Lunch, Posters, Exhibits**	
12:15 - 1:00	**Chair:** Deepak Gokaraju, *Metarock Laboratories* **Keynote:** Failure of Anisotropic Rocks such as Shales, and Implications for Borehole Stability	**Robert W. Zimmerman** and Widad Al-Wardy, *Dept. of Earth Science and Engineering, Imperial College of Science, Technology and Medicine, London, UK.*
	Session 2: Optimizing Completion Footprint and Stimulation Designs **Chairs:** Ashwani Zutshi, *Schlumberger*; Mark Morford, *FracGeo*	
1:05 - 1:40	Digital Rock Simulation: A Novel Approach for Accurate Characterization of Perforation Tunnel Damage	**Rajani Satti**, *Baker Hughes*
1:40 - 2:15	Digital Twins for Drilling Fluid and How Digitalization Could Help to Reduce the Cost and Increase the Wellbore Stability	**Mehrdad G Shirangi,** Reza Ettehadi, and Charles A Thompson Jr, *Baker Hughes*
2:15 - 2:35	**Coffee, Posters, Exhibits**	
2:35 - 3:10	Stress Sensitivity of Sonic Wave Velocity and the Reliability of Sonic Tools in Unconventional Tight Gas Sand Reservoirs	Dr. Christophe Germay and **Tanguy Lhomme**, *EPSLOG*
3:10 - 3:45	Characterizing Off-Normal Occurrence and Leakage Risk at Underground Natural Gas Storage Facilities	**Richard A. Schultz**, *Orion Geomechanics*
3:45 - 4:45	**Open Floor Discussion & Posters**	

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Oral Presentations – Thursday, November 7, 2019

7:00	**Registration and Coffee**	
8:00 - 8:10	**Welcome and Opening Remarks:** Umesh Prasad, *Baker Hughes*	
	Session 3: Post-stimulation Diagnostics and Monitoring **Chairs:** David Katz, *Baker Hughes*; Jing Zhang, *The University of Oklahoma PhD Student*	
8:10 - 8:45	Geomechanics of Unconventional Hydraulic Fracturing: Clusters, Complexity, "Frac-Hits" and All That	**Ahmad Ghassemi**, *The University of Oklahoma*
8:45 - 9:20	Estimation of Propped Fracture Geometry Using Electromagnetic Geophysics	**Terry Palisch** and **Souvik Mukherjee**, *CARBO Ceramics*
9:20 - 9:40	**Coffee, Posters, Exhibits**	
9:40 - 10:15	Near and Far Field DAS Diagnostics for Unconventional Reservoir Monitoring	**Andres Chavarria**, *Optasense*
10:15 - 10:50	Early Warning Systems – Using PTA Analysis of DFITs to Understand Complex Hydraulic Fractures and Optimize Treatment Designs	**Bob Bachman**, *CGG*
10:55 - 11:55	**Open Floor Discussion & Posters**	
11:55 - 1:00	**Lunch, Posters, Exhibits**	
12:15 - 1:00	**Chair:** Deepak Gokaraju, *MetaRock Laboratories* **Keynote:** Integrating Geology and Geophysics into Engineering Workflows to Enhance Unconventional Production **Poster Winner Awards**	**Tony Settari**, *CGG Services (Canada) Inc.*
	Session 4: Extending the Life of the Field: Production, Refracturing, and EOR **Chairs:** Barbara Hill, *Schlumberger*; Chi Vinh Ly, *CGG*	
1:05 - 1:40	Role of Multiple Fracturing of Vertical And Horizontal Wells in Maximizing Production and Extending Life of the Field	**Mohamed Soliman**, *University of Houston*
1:40 - 2:15	Limits on the Accuracy of Pore Pressure Estimates by Analysis of Random Measurement Error and Means for Improvement	**Mark Herkommer**, *Qube Tech LLC*
2:15 - 2:35	**Coffee, Posters, Exhibits**	
2:35 - 3:10	Extending the Life of Enhanced Permeability Zones Created During Hydraulic Fracturing	Ron Dusterhoft, **Zeno Philips** and U. Inyang, *Halliburton*
3:10 - 3:45	Predrill Pore Pressure Estimation in Wildcat Prospectivity	**Saad T. Saleh**, *GEOMECH, USA*
3:45 - 4:45	**Open Floor Discussion & Posters**	
	Closing Comments	

Poster Session

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

Posters – November 6-7, 2019

Poster Session Chair: Mike Effler, James Kessler

University	Student Name	Poster Topic
Georgia Institute of Technology	**Ming Lui**	Poroelastic Indentation – Feasibility of a New Testing Method for Tight Rocks
Oklahoma State University	**Jingyao Meng**	Geomechanical Characteristics of the Prospective CO_2 Sinks and Seals, Eastern Gulf of Mexico
Purdue University	**Wenging Wang**	Heterogeneous Stress State in the Crystalline Crust Beneath the Western Canadian Sedimentary Basin: Observations from Borehole Image Logs to 2.4 km
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Purdue University • The University of Oklahoma
The University of Texas • University of Calgary
University of Houston

Abstracts

Oral Presentations
Day One

November 6, 2019

Southwestern Energy
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Wednesday, November 6, 2019 | Session 1 | 8:10
Colin M. Sayers
Schlumberger

Advanced Seismic Inversion for Geomechanics Applications in Unconventional Reservoirs

Summary
Due to low permeability, economic production from unconventional reservoirs requires increasing the surface area in contact with the reservoir via hydraulic fracturing. Important to the design of efficient hydraulic fractures is an understanding of pore pressure, the orientation and magnitude of principal stresses, the geomechanical properties of the rock, and the density and orientation of any natural fractures. Such understanding can be achieved using AVA (Amplitude Variation with Angle) inversion of properly processed, imaged, and well calibrated surface seismic data to build a predictive 3D Mechanical Earth Model (MEM). Because shales are usually anisotropic, MEMs built using isotropic inversion may fail to describe hydraulic fractures correctly. The use of anisotropic seismic AVA inversion for building 3D MEMs is illustrated using examples from North America. The results enable optimization of well location, borehole trajectory, well spacing, and the design of hydraulic fractures, before the well is drilled.

Introduction
Economic production from unconventional reservoirs requires increasing the surface area in contact with the reservoir via hydraulic fracturing. The design of hydraulic fractures requires understanding of pore pressure, the orientation and magnitude of principal stresses, the geomechanical properties of the rock, and the density and orientation of any natural fractures. This can be achieved using AVA (Amplitude Variation with Angle) inversion of properly processed, imaged, and well calibrated surface seismic data to build a predictive 3D Mechanical Earth Model (MEM). A 3D MEM consists of a structural framework, with geological surfaces and faults from seismic interpretation, mechanical stratigraphy, obtained by identifying the various lithoclasses using inverted P-impedance and VP/VS, elastic properties and rock strength parameters obtained from P-impedance and VP/VS using dynamic-to-static transforms calibrated to geomechanical measurements on core, and estimates of pore pressure, vertical stress, minimum and maximum horizontal stress, stress direction, and the density and orientation of natural fractures.

Shales are usually anisotropic, and a neglect of shale anisotropy may lead to an incorrect estimate of geomechanical properties and in-situ stress. As a result, MEMs built using isotropic inversion may fail to describe hydraulic fractures correctly. In addition to the intrinsic anisotropy of shales, anisotropy due to the presence of natural fractures, and due to horizontal stress anisotropy, plays an important role in determining the geometry of hydraulic fractures in unconventional reservoirs. The presentation will introduce anisotropic AVA inversion, followed by the application of the results to lithoclassification, determination of geomechanical properties, pore pressure and the prediction of minimum and maximum horizontal stress and fracture gradient using anisotropic poroelasticity. Next, the construction of a 3D FEM (Finite Element Model) is discussed with application to the determination of the spatial variation in stress based on the inversion results. The perturbation in the stress field due to faults is then discussed and the possible use of AVOAz (Amplitude Variation with Offset and Azimuth) inversion to calibrate the mechanical properties of the fault is outlined.

Example
An example of horizontal stress anisotropy

$$A = 2(\sigma_H - \sigma_h)/(\sigma_H + \sigma_h)$$

computed using a 3D FEM constructed using the results of seismic AVA inversion is shown in **Figure 1** (Sayers et al., 2019).

Conclusion
Detailed knowledge of pore fluid pressure and in-situ rock stresses are required to model the propagation of hydraulic fractures. Pore pressure and in-situ stress can be characterized by means of seismic AVA inversion, allowing well location, borehole trajectory, well spacing, and the design of hydraulic fractures, to be optimized before wells are drilled.

Acknowlegement
The author thanks Ran Bachrach, Sagnik Dasgupta, Lennert den Boer, Edan Gofer, Charles Inyang, Maria Lascano, David Ng, David Paddock, Vasudhaven Sudhakar, and Andy Walz for their contributions to this work

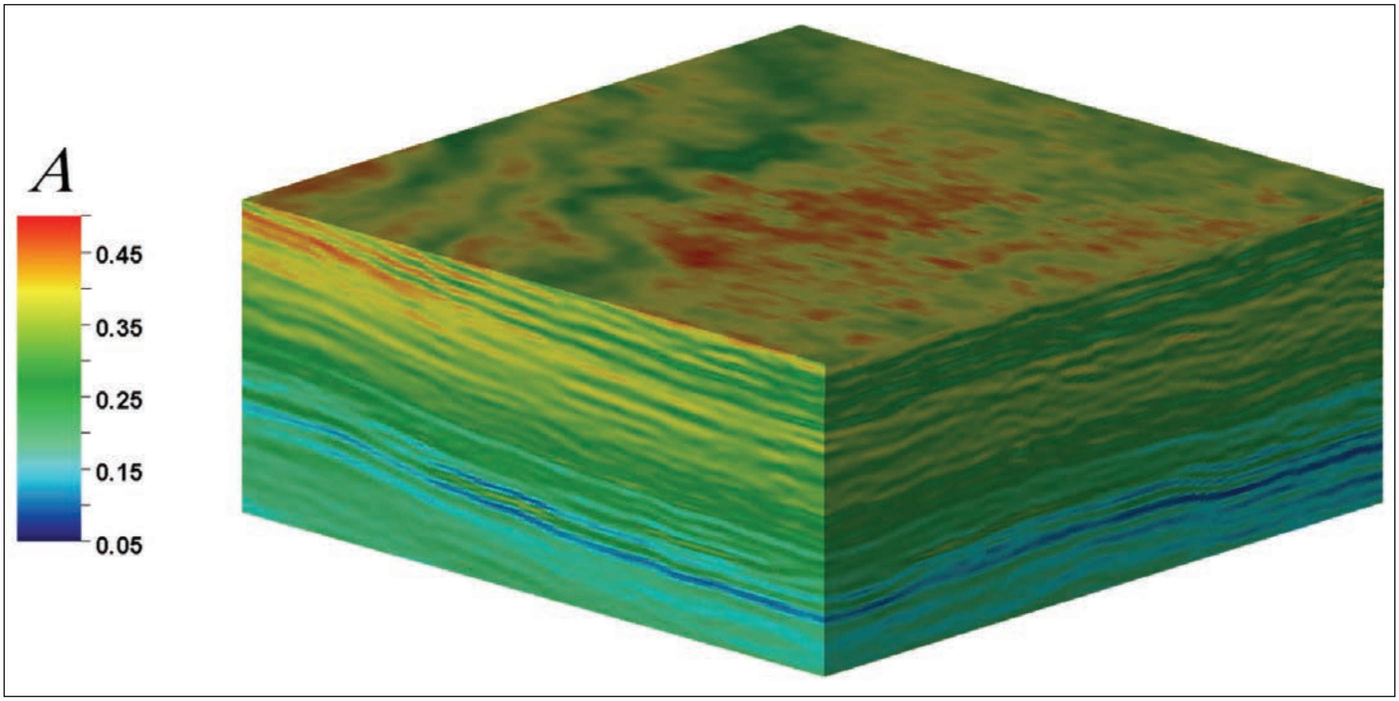

Figure 1. *Horizontal stress anisotropy derived for a region within the Permian Basin using the finite element method (Sayers et al., 2019).*

References

Sayers, C.M., Dasgupta, S., den Boer, L.D., Gofer, E., Lascano, M., Paddock, D., Sudhakar, V. and Walz, A., 2019. Seismic inversion for engineering applications in unconventional reservoirs. In *SEG Technical Program Expanded Abstracts 2019* (pp. 4740-4744). Society of Exploration Geophysicists.

Biographical Sketch

Colin M. Sayers is a Scientific Advisor in the North America Land Seismic Group in Houston. He entered the oil industry to join Shell's Exploration and Production Laboratory in Rijswijk, The Netherlands in 1986, and moved to Schlumberger in 1991.

He is a member of the AGU, EAGE, GSH, HGS, SEG, and SPE, a member of the Research Committee of the SEG, and has served on the editorial boards of the International Journal of Rock Mechanics and Mining Science, Geophysical Prospecting, and The Leading Edge. He has a BA in Physics from the University of Lancaster, U. K. and a PhD in Physics from Imperial College, London, U.K. In 2010 he presented the SEG/ EAGE Distinguished Instructor Short Course "Geophysics under stress: Geomechanical applications of seismic and borehole acoustic waves". In 2013 he was awarded Honorary Membership of the Geophysical Society of Houston "In Recognition and Appreciation of Distinguished Contributions to the Geophysical Profession". He received an award for best paper in *The Leading Edge* in 2013.

Wednesday, November 6, 2019 | Session 1 | 8:45
Agus Tjengdrawira, Julie Kowan, and Namsu Park,
Baker Hughes

Lost-in-Hole Diagnostics and Mitigation

Super-laterals are becoming more common to access reserves and improve oil and gas production in various land basins across the United States and internationally. Technology advancements, including rotary steerable systems, enable these laterals to be drilled faster, often in record times. Though intended to increase efficiency and minimize expenses, these extended laterals can sometimes result in an increased amount of drilling problems such as pack offs, tight holes, and stuck pipes, which led to numerous lost in-hole (LIH) incidents in recent years. These drilling problems can be related to operational parameters and/or subsurface conditions.

As these laterals are typically drilled with very limited petrophysical and geological data acquisition, it is often difficult to properly identify the cause(s) of any stability issues. It follows that it is also difficult to determine effective mitigation options to reduce the risk of LIH incidents and the associated cost of drilling replacement wells. Adding to the complexity of the problem, the subsurface conditions in many fields have been altered, including the formation pressure, stresses, and rock properties, due to past and ongoing stimulation and production operations.

To tackle these challenges, we have developed a diagnostic workflow to identify a set of factors likely to contribute to the stability issues commonly associated with LIH incidents. Correct identification of the contributing factors allows us to develop proper mitigation strategies. Our workflow begins with an exhaustive review of available field data including geological, seismic, petrophysical logs, and downhole measurements from nearby offset wells, along with geosteering information, drilling, completion, stimulation, and production data. We then compare our observations to the expected signs/symptoms associated with each possible contributing factor, followed by appropriate analyses, including but not limited to, geomechanical, reservoir, hydraulics, drilling dynamics modeling in order to test the likelihood of each factor contributing to the LIH event. Based on the results, we construct a table ranking the likelihood of each factor contributing to the LIH incidents and provide mitigation recommendations. We can then incorporate these specific LIH mitigation strategies into an overlying risk mitigation framework for the specific fields/areas of operations.

We have applied this diagnostic workflow in a number of LIH studies in the United States, enabling operators to employ mitigation actions in a systematic manner. Case studies are included to highlight the value of the workflow.

Biographical Sketches

Agus Tjengdrawira, Subject Matter Lead - Geomechanics: Agus gained 3 years of experience as a logging-while-drilling (LWD) field engineer, 4 years as LWD petrophysicist, and 2.5 years experience as a Geomechanics specialist prior to joining Baker Hughes Geoscience and Petroleum Engineering (GPE) group in November 2007. Since then he has gained almost 12 years experience as a senior geomechanics specialist/advisor with Baker Hughes, conducting studies for operators in the Gulf of Mexico, across unconventional plays in US Land, Canada, Southern Mexico Marine Region, Southeast Asia, Australia, and Japan.

His expertise includes wellbore stability, pore pressure prediction, rock testing management and QC, 3D finite-element (FE) modeling and simulation for near-salt drilling, compaction and subsidence, sanding production prediction, casing collapse, fault stability and lost-in-hole analyses. Agus has been the technical team lead of the GPE North American geomechanics consulting team since 2018, with responsibilities involving day-to-day operations management of the team, reviewing higher-end, more complex geomechanical studies, proposal and pricing, providing input to sales/business strategy and mentoring other specialists.

Julie Kowan, Geomechanics Advisor: Ms. Kowan has over 12 years of experience enabling operators to drill safer, more cost-effective wells and plan field development by reducing non-productive time (NPT) due to wellbore instability and improving production. She has expertise in unconventional reservoirs, pore pressure prediction, stress constraint, wellbore stability, fracture permeability and compaction. Ms. Kowan began her career as a Geomechanics Associate at GeoMechanics International (GMI) in 2005 before being promoted to Specialist and Advisor positions at GMI and Baker Hughes.

From 2016 to 2018, she ran her own successful consulting company, J. Kowan Consulting, LLC, before re-joining Baker Hughes in 2018. Ms. Kowan 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 previously served as Secretary.

Namsu Park, PhD, Petroleum Engineering Lead – North America: Dr. Park currently leads a talented petroleum engineering team consists of geomechanics, geomodeling, reservoir engineering, and completion & production engineers. His business focus is to provide expert technical advisory services to external clients and BHGE Geomarkets / Product Lines. He has been involved with numerous reservoir consulting projects from US land, Gulf of Mexico, Canada, Caribbean and other parts of world. His technical background and experiences cover various aspects of reservoir geomechanics, 3D subsurface modeling, experimental rock mechanics, and hydraulic fracture diagnostics.

Prior to joining Baker Hughes, he worked for Pinnacle Technologies as a diagnostics development engineer. He holds a PhD in petroleum engineering from The University of Texas at Austin. His PhD research was focused on the Discrete Element Modeling (DEM) of rock fracture behavior and its effect on long-term stability.

Wednesday, November 6, 2019 | Session 1 | 9:40
Ashabikash Roy Chowdhury, Umesh Prasad, and Ryckman Callais,
Baker Hughes

Laboratory Modelling of Salt Deformation and its Correlation with Drilling Mechanics of Record Hybrid Drill Bit Runs in the Gulf of Mexico

Summary

The continued focus of operators to drill wells safely and at reduced costs, leads to innovation and adaptation of practices and equipment which could help achieve these goals. Though the on-bottom drilling time for most deepwater wells in the Gulf of Mexico (GOM) is between ten to fifteen percent of the total drilling time[1], further reduction of on-bottom drilling time using suitable drill bit technology creates significant value, due to high spread costs per day. This endeavour has led to a sustained application of a hybrid drill bit with dual-cutting mechanics for drilling salt at improved penetration rates.

Target reservoirs in many areas of the central GOM lie beneath a thick sequence of salt. Due to the plastic behaviour of salt, it requires a higher compressive load to break. Conventional polycrystalline diamond compact (PDC) bits break the rock by shearing. PDC bits have a narrow stability window that moves to a dynamic instability mode under higher compressive loads. This instability mode leads to potential downhole tool failure and non-productive time (NPT). Since the introduction of hybrid bits with dual-cutting mechanics, combining the gouging action of a roller-cone bit and the shearing action of a PDC bit, salt sections are successfully drilled at record penetration rates.

The current literature uses field drilling data from very successful hybrid bits run in salt zones, and attempts to establish a correlation with laboratory-generated salt deformation data.

Introduction

Wells drilled in the central Gulf of Mexico routinely penetrate a thick sequence of salt[2] to reach deeper reservoir rocks. Because of the plastic nature of salt, it has a potential to creep that prompts operators to drill salt at a faster rate of penetration (ROP), and cover it with casing[3]. Improving the ROP also helps to lower the drilling cost. Drilling practices and technologies evolve to address the requirements of drilling salt fast.

A hybrid bit technology (**Figure 1**), combining PDC and tungsten carbide insert (TCI) cutting elements[2], has proven to be an enabling technology for drilling salt and sub-salt clastic formations and has established a benchmark for penetration rates.

The regular success of hybrid drill bits in drilling salt inspired the authors to investigate a potential correlation between laboratory data and drilling mechanics using actual field drilling data from hybrid drill bits. The study also aims to encourage drilling engineers to look beyond rock strength and abrasivity, and use the deformation properties of rocks and their compatibility with the available cutting mechanics of prevalent bit types to ensure success. Since salt has a homogenous fabric, it was used for laboratory modelling to ensure an unvarying deformation environment for comparison.

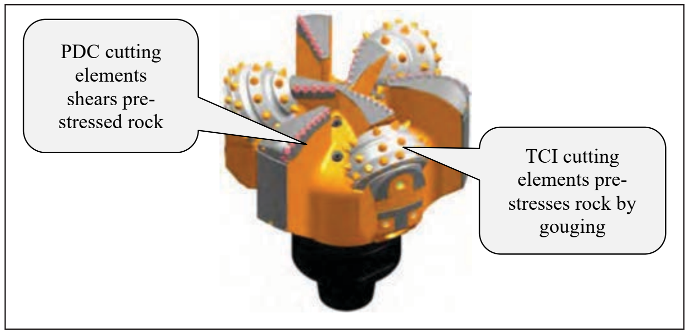

Figure 1. *Generic hybrid drill bit showing TCI and PDC cutting elements*

Background

While selecting bit types, drilling engineers take into consideration rock strength and its abrasivity to ensure cutting structures are able to cut the rock efficiently. Each selected bit type is generally equipped with cutting elements that offer a single cutting mechanics. Because of the wide variety of rocks that a single bit run penetrates, bits with a single cutting mechanics are unable to drill both commonly occurring clastic rock types and salt efficiently due to divergent mechanical

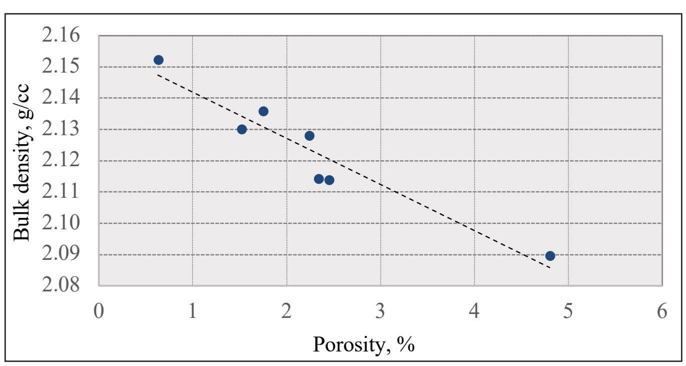

Figure 2. *Density and porosity of core plugs*

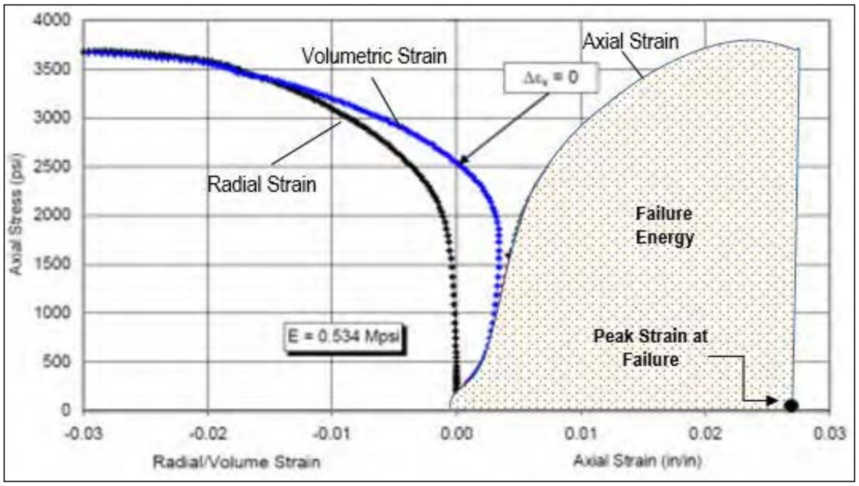

Figure 3. *Axial, radial and volumetric strain with applied stress*

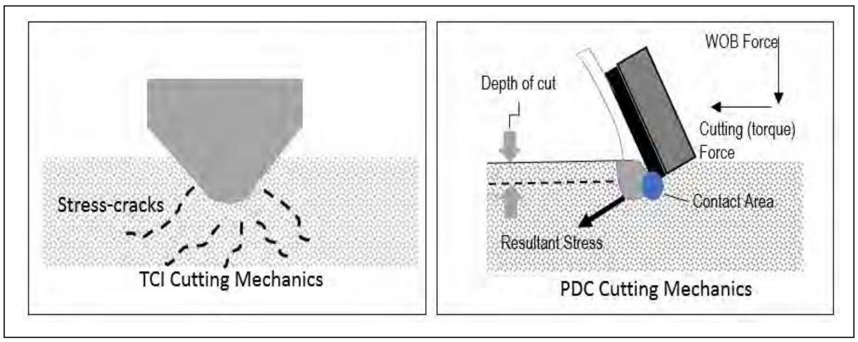

Figure 4. *Cutting mechanics and stress area for TCI and PDC cutting elements*

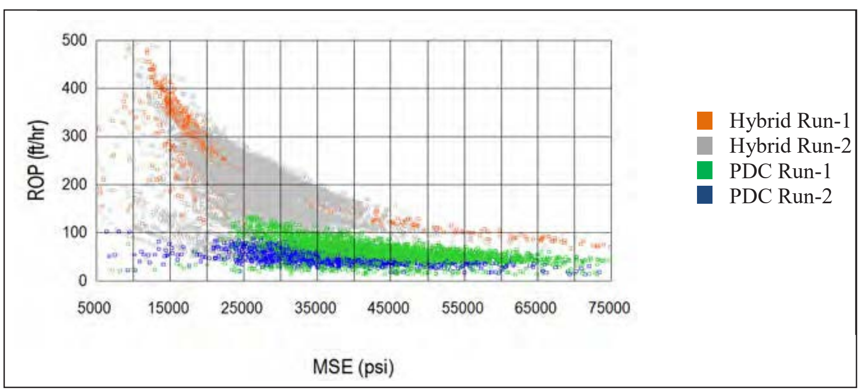

Figure 5. *Drilling efficiency of hybrid and PDC bit run*

properties. Salt at an ambient condition appears to be solid, but it is a weak rock and is unable to withstand differential stresses that makes it flow and attain unusual shapes[4,5]. Its lower-than-usual bulk density and extremely low porosity differentiates it from other rock types. As a result, using a standard PDC bit that uses shearing action to break salt compromises the penetration rate.

Unlike PDC bits, a hybrid drill bit combines simultaneous on-bottom gouging and shearing action. The gouging action pre-stresses and weakens the rock that is subsequently removed by the PDC cutting elements, easily offering an improved penetration rate. This advantage of hybrid drill bits has enabled operators in the Gulf of Mexico to drill salt at higher ROPs.

The dual-cutting mechanics of a hybrid bit offers several other benefits, such as improved torsional stability, and better bit and concentric reamer matching[6,7]. These topics are beyond the scope of the current publication.

Laboratory Testing of Salt Deformation

To establish a correlation with salt drilled in the GOM, several core plugs of 1.5 x 3.0-in. were drilled from a block of quarried salt. Porosity and density of the plugs were measured (**Figure 2**) to ensure they were within the range of salt drilled in the GOM. X-ray diffraction indicated the primary constituent being halite, but minor amounts of quartz, calcite, anhydrite and dolomite were also noted.

The compressive strength of the core plugs was tested at atmospheric pressure as well as under different confining pressures up to 15,000 psi to mimic downhole conditions. A tri-axial load frame was used for measuring axial, radial, and volumetric strain using varying rates to replicate the faster penetration rates while drilling.

The axial-stress, axial-strain and radial-strain measured during tests were plotted (**Figure 3**). The Young's modulus of 0.534 mpsi was calculated. The failure strain was excessively high, approximately 2.7% as compared to 0.3 to 0.5% in most conventional rock types. Although the unconfined compressive strength (UCS) and Young's modulus remained low in comparison to conventional rock types, the failure energy was large due to high strain at failure.

Microscopic examination of a thin section highlighted the crystalline nature of the salt, and the fracture pattern resulting from compressive loading. The absence of a failure plane was noted, and fractures were distributed all along the sample, indicating a ductile nature.

Cutting Mechanics of Hybrid Drill Bit

The dual-cutting mechanics of the hybrid drill bit were simulated using distinct element modelling, which indicated that the deeper indentation and gauging action of TCI cutters create a larger volume of weakened rock (**Figure 4**) due to stress, and they are subsequently sheared by the PDC cutters at an improved rate.

Drilling Mechanics of Hybrid Drill Bit

Real-time drilling data from a successful 26-in. hybrid drill bit run were used for comparison of the drilling mechanics of hybrid and PDC bits run in salt. The mechanical specific energy

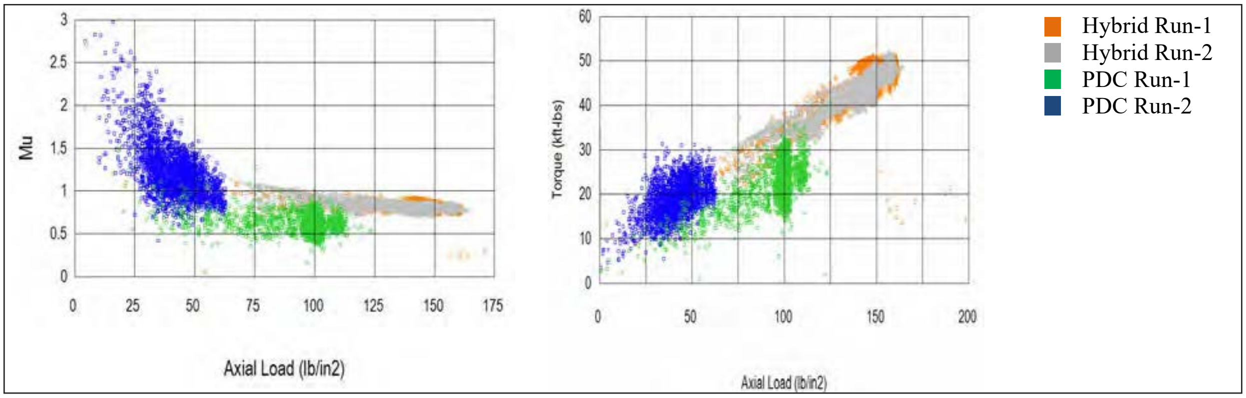

Figure 6. *Aggressiveness (Mu) and torque response comparison between hybrid and PDC bits*

(MSE)[8] was plotted against the ROP (**Figure 5**) and compared against offset PDC runs in salt.

Hybrid drill bits penetrated salt significantly faster than PDC bits. Lower specific energy values for hybrid bits highlighted this improved drilling efficiency.

A comparison of aggressiveness[7,8] between hybrid and PDC bits (**Figure 6**) highlights that hybrid bits have a lower spread value and improved linearity for aggressiveness and torque.

The torque and axial load curves also highlight the ability of a hybrid bit to operate under higher axial load with better torsional stability, delivering higher drilling efficiency. This confirms the laboratory test results mentioned earlier. Superior torsional stability of the hybrid bit provides a wider stability window of operation.

Conclusions

Based on the work included in the present paper, the following can be concluded:

1. The tri-axial test of a salt plug confirms high strain at failure, suggesting a high energy requirement for deformation.

2. Laboratory tests re-confirm the low density, low porosity, and low Young's modulus of salt.

3. The high axial load needed to drill salt is due to high strain at failure.

4. Hybrid bits have a higher drilling efficiency, and drill salt with lower MSE compared to PDC bits.

5. Due to linear and lower spread values for torque, hybrid bits have improved torsional stability.

Acknowledgements

The authors would like to thank Baker Hughes for supporting this work. Special thanks are due to the technical publication team and Subject Matter Experts of Baker Hughes for providing technical and editorial insight.

Formulas

$$Axial\ Load = \frac{WOB}{Area}$$

$$MSE = \frac{WOB}{Area} + \frac{13.33 * \mu * WOB * RPM}{D * ROP}$$

$$Mu\ \ (\mu) = \frac{36 * Torque}{D * WOB}$$

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Biographical Sketches

Roy Chowdhury, holds a MSc degree in Geology from University of Lucknow, India, and has 35 years of upstream industry experience, with Baker Hughes. He started his career in wellsite geology in far-East Asia, and gained wider field experience in drilling and evaluation portfolio available within the Baker Hughes including wellbore positioning, LWD, directional drilling, and drilling optimization. He managed the field engineer training function in Singapore, prior to moving to UAE, where he managed the drilling and LWD operation.

Roy Chowdhury holds dual Oasis™ certification in bit and drilling optimization, and currently works as an Application Engineering Advisor for Baker Hughes in Houston. His current technical interest is in the field of drilling mechanics and rock-deformation, drilling dynamics, and fluid hydraulics. He takes keen interest in the activities of SPE and AADE as a member, and has fifteen publications to his credit.

Umesh Prasad, PhD, is an Engineering Manager – Geoservices at Baker Hughes in Houston, Texas. He has been with the company for seventeen years. He is focused on Geomechanics, rock testing, and rock characterization from physical, mechanical, mineralogical, and textural points of view, including performing QA/QC on rock mechanical properties, and modeling and calibrating log-based rock properties. Previously, he conducted experimental research work at the University of Toronto. He holds a Bachelor's degree in Mining Engineering from the Indian School of Mines, and an M. Eng. and a Ph.D. in Mining and Metallurgical Engineering from McGill University, Montreal, Canada.

Ryckman Callais, is Technical Support Manager, North America Offshore at Baker Hughes, located in Broussard, Louisiana. He holds BS degree in Mechanical Engineering from Louisiana State University and leads the application engineering team for offshore operations. He is a member of several professional societies including AADE, ASME, and NACE, and has authored several papers and articles..

Wednesday, November 6, 2019 | Session 1 | 10:15
David P. Yale
Geomechanics Consulting
Vivek Swami, Adriana Perez, Robert Raney
CGG, Geoconsulting Americas

Novel Pore Pressure Prediction Technique for Unconventional Reservoirs

Standard seismic/ acoustic log pore pressure (Pp) prediction techniques developed for young sediments in offshore basins are not very effective in unconventional reservoirs. The age and lithification of shale reservoirs, the variability in lithology, and different overpressure generation mechanisms and basin histories all lead to poor quality predictions using standard Eaton or Bowers methods. However, pore pressure prediction remains important in unconventional reservoirs due to the correlation between over-pressured areas and productivity, and the correlations between thermal maturity and pore pressure.

We have developed a method that extends the theoretical basis of the Eaton and Bowers methods to the geologic and basin history conditions of unconventional reservoirs. The method has been developed using standard log suites along with dipole acoustic logs. Key components of the method are:

1. Use of a normal pressure trend section of wells and extension of that trend to deeper, over-pressured zones,

2. Correction of sonic velocities for lithologic and porosity variations through rock physics models and lithology logs,

3. Use of lith logs to determine Biot alphas and thus accurate effective stresses and thus pore pressures,

4. Calibration of the predicted pressure profile with measured pore pressures from DFIT, DST, or shut-in pressures.

A test of the method in a series of 32 wells in Wyoming's Powder River Basin have shown it to be very effective for a range of productive formations across the basin. We find little measured pressure data is needed to calibrate the results, and that most of the measured pressure data serves to validate the method and its ability to predict pressures in multiple formations. Nevertheless, the effectiveness of the method over a range of wells and formations gives credence to the theoretical underpinnings of the method. Integration of results from multiple wells and with geochemistry, thermal maturity, and basin modeling gives insight into overpressure generation and expulsion mechanisms. ■

Biographical Sketches

Mr. Swami has over 12 years of experience in geomechanics, reservoir engineering and well completions. He has participated in large reservoir and geomechanical engineering studies for clients in Canada, USA, Middle East and South America and has worked for operating companies in India as Petroleum/Well Completions Engineer. His engineering experience lies in the areas of pore pressure estimation, building 1D and 3D MEMs, shale gas simulation, caprock integrity, mini-frac analysis and hydraulic fracturing modeling and execution within a multi-disciplinary team environment. He holds B.Tech (Indian School of Mines, India) and M.Sc. (U. of Calgary, Canada), both in Petroleum Engineering.

Wednesday, November 6, 2019 | Keynote | 12:15

Robert W. Zimmerman
Earth Science & Engineering, Imperial College London

Failure of Anisotropic Rocks such as Shales, and Implications for Borehole Stability

Summary

A new model for borehole stability in shale formations is described. The stress state around the borehole is computed as a function of the the in situ principal stresses, the elastic moduli, and the orientation of the borehole, using Lekhnitskii's anisotropic elasticity solution. Shear failure around the borehole is modeled with a modified Jaeger plane of weakness model, in which failure through the "intact rock" is assumed to be governed by the fully-triaxial Mogi-Coulomb criteria. Calculations for hypothetical cases using plausible shale parameters illustrate the effect that using a true-triaxial failure criterion, and an anisotropic elastic stress model, will have on the predicted critical mud weight.

Introduction

In anisotropic rocks, the value of the maximum principal stress required to cause shear failure depends on the other two principal stresses, and on the angle β between the maximum principal stress and the normal to the bedding plane. According to Jaeger's plane of weakness model, for β near 0° or 90°, failure will occur at a stress determined by the failure criterion for the "intact rock", and the failure plane will cut across the bedding planes. At intermediate angles, failure will occur along a bedding plane, at a stress determined by the strength parameters of the bedding plane. The resulting four-parameter strength model provides a good fit to triaxial compression data on Vaca Muerta and Bossier shales (Ambrose et al., 2014). Based on this failure model, a wellbore stability model has been developed for boreholes drilled in shales.

Description of Model and Results

In Jaeger's model for the shear failure of "transversely isotropic" media containing bedding planes, failure along such a plane is assumed to be governed by the following criterion (see Ambrose et al., 2014, for details):

$$\sigma_1 = \sigma_3 + \frac{2(S_w + \mu_w \sigma_3)}{(1 - \mu_w \cot\beta)\sin 2\beta},$$

where S_w is the inherent cohesion of the planes of weakness, μ_w is the coefficient of internal friction along those planes, and β is the angle between σ_1 and the normal to the planes of weakness. In Jaeger's original model, failure was also assumed to be possible along a plane that is not parallel to the bedding; failure along these planes is assumed to be governed by the Coulomb criterion. In the present model, failure through the "intact rock" is assumed to be governed by the fully-triaxial Mogi-Coulomb criterion, which is known to be more accurate (Al-Ajmi and Zimmerman, 2006):

$$\tau_{oct} = a + b\sigma_{m2},$$

where $\tau_{oct} = \frac{1}{3}\sqrt{(\sigma_1-\sigma_2)^2+(\sigma_1-\sigma_3)^2+(\sigma_2-\sigma_3)^2}$, and $\sigma_{m2} = (\sigma_1+\sigma_3)/2$.

The fully anisotropic Lekhnitskii (1963) solution is then used to compute the stresses around the borehole wall. The model can be used to predict the minimum mud weight required to avoid shear failure, for arbitrary borehole orientations and anisotropy ratios. A graphical illustration of the estimated critical mud weight is shown in **Figure 1**; more details can be found in Setiawan and Zimmerman (2018). ■

Acknowledgements

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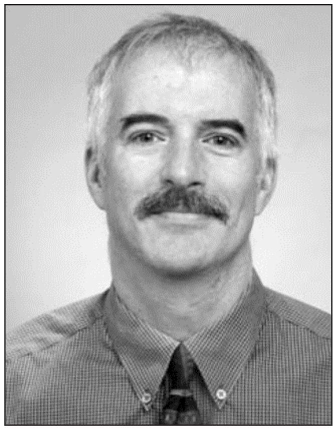
Biographical Sketches

Robert Zimmerman is Professor of Rock Mechanics in the Department of Earth Sciences at Imperial College, London. He received a BS and MS in mechanical engineering from Columbia University, and a PhD in continuum mechanics from the University of California at Berkeley. He has been a lecturer at UC Berkeley, a staff scientist at the Lawrence Berkeley National Laboratory, and Head of the Division of Engineering

Geology and Geophysics at the Royal Institute of Technology in Stockholm.



He is Editor-in-Chief of the *International Journal of Rock Mechanics and Mining Sciences*, and is also on the Editorial Boards of *Transport in Porous Media*, and the *International Journal of Engineering Science*.

He co-author, with J. C. Jaeger and N. G. W. Cook, of the definitive monograph "Fundamentals of Rock Mechanics", 4th ed. (Wiley-Blackwell, 2007). He is the author of the monograph "Compressibility of Sandstones" (Elsevier, 1991) and the textbook Fluid Flow in Porous Media (World Scientific, 2018).

In 2010 he received the Maurice A. Biot Medal for Poromechanics from the American Society of Civil Engineers, for "his outstanding contributions in applying poroelasticity to rock mechanics and fluid flow in fractured media".

His papers and books have received over 14,000 Google Scholar citations.

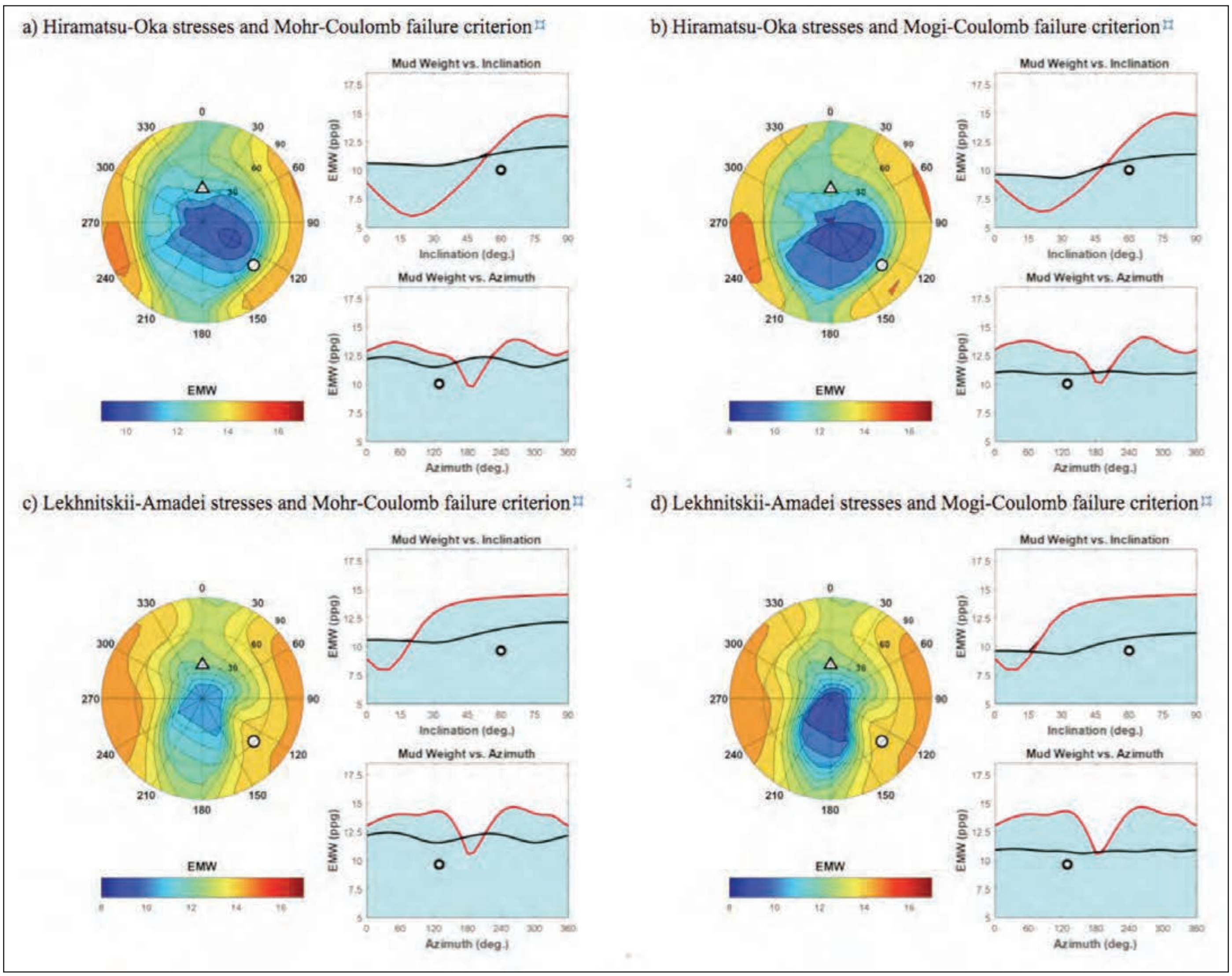


Figure 1. *Minimum mud weight to avoid shear collapse, for an inclined wellbore. The center of the polar diagram represents a vertical wellbore, and the outer ring corresponds to horizontal wellbores. The drilling azimuthal direction is measured from north (top), in the clockwise direction. The white dot indicates a deviated wellbore with a 60° inclination from the vertical, towards N 130° E. The bedding direction is shown by the small triangle which, in this example, illustrates a 30° dip of a weak bedding plane towards north. More details are given in Setiawan and Zimmerman (2018).*

Rajani Satti
Baker Hughes

Digital Rock Simulation: A Novel Approach for Accurate Characterization of Perforation Tunnel Damage

Shaped charge jet perforation is the most widely used method for establishing hydraulic communication between the formation and the wellbore. A primary objective of this method is to create “clean” tunnels that can efficiently transport hydrocarbons. However, during the perforating event, the detonation of the explosive charge inevitably compresses the formation, resulting in “crushed” or “damaged” rock surrounding the tunnel. This damaged region significantly reduces permeability and severely impedes the flow efficiency of the perforation tunnel. Consequently, it is critical to understand the physical characteristics (thickness and permeability/porosity) of the damaged zone while designing and optimizing perforating jobs. The small-length scales and arbitrary surfaces that encompass the damaged zone make it almost impossible and impractical for laboratory or traditional modeling methods to quantitatively measure the damaged perforation zone.

In this study, a state-of-the-art digital rock simulation approach is used to conduct a detailed study of the damage mechanism surrounding a typical perforation tunnel. As part of this work, an API RP19-B Section IV test was conducted using a Berea sandstone core. The perforated core was then sectioned and smaller core plugs were drilled around the expected damage zone at various locations. For each core plug, digital rock analysis was conducted in two steps. The first step relates to digital rock generation consisting of micro-scale CT scanning, sample segmentation to give the three-dimensional representation of the pore-space structure, and pore space characterization. In the second step, a Lattice Boltzmann model was used to simulate single-phase fluid flow through various subdomains of the rock and predict the absolute permeabilities.

The computed results from this study included continuous profiles of absolute permeability and porosity along with the thickness of the crushed zone. Pore size distributions (PSD) of selected subdomains were used to better characterize the pore-space. The porosity, PSD, and permeability data in the damaged zone quantified the damaged zone thickness, and showed the trends of how rock properties were significantly altered in the damage zone. The effect of the perforation process on the anisotropy of the rock properties was investigated by simulating cross-flow permeabilities in addition to the main-flow permeabilities. Further, three-dimensional whole-field visualization of physical properties and statistics within the rock structure were also presented.

This study demonstrates a novel digital rock physics simulation approach that can be used to reliably measure the complex characteristics of a crushed zone surrounding the perforation tunnel. Computed rock characteristics data provided insight into the true physical characteristics of the crushed zone. These characteristics can be used in large-scale computational fluid dynamics (CFD) models to accurately simulate productivity, produce dynamic perforation clean-up models, and most importantly, evaluate and understand the performance of shaped charges.

Biographical Sketch

Rajani Satti received his PhD from University of Oklahoma in 2007. He received his Master’s from Kettering University in 2003. He has been with Baker Hughes for 9 years and served as both technology and product manager in the areas of drilling and completions, perforating, fracturing and stimulation. He has a successful track record of transforming research into commercial products and has more than 70 publications including journals, conferences and symposiums.

Wednesday, November 6, 2019 | Session 2 | 1:40
Mehrdad G Shirangi, Reza Ettehadi, and Charles A Thompson Jr.
Baker Hughes

Automated Machine Learning for Accurate Real-Time Prediction of HPHT Drilling Fluids Properties

Abstract

Control and timely adjustment of drilling fluids properties at the rigsite is crucial for wellbore stability and safe drilling operations. This requires real-time determination and monitoring of downhole rheological properties and equivalent circulating density (ECD) of the drilling fluids. Currently, the measurements of drilling fluids properties are performed at surface conditions on the rig site, whereas these properties may be significantly different at downhole high pressure/high temperature (HPHT) conditions. To measure drilling fluids rheological properties at HPHT conditions, fluid samples are sent to technical labs and test results become available within a few days.

In this work, we develop and apply an automated machine learning methodology that learns from historical data records, collected during 25 years of operations. The goal is to predict drilling fluids rheological properties at downhole pressures and temperatures, given the measurements conducted at surface conditions, and the mud composition data. After training hundreds of machine learning models, the most accurate model corresponds to more than 96% cross-validation accuracy. The resulting model was tested with a holdout set, and can be deployed for use at rig operations.

Introduction

It is often said that most of the drilling problems (e.g., drilling fluid losses, formation fluid influx, stuck pipe) are related to the drilling fluids ('mud'). Therefore, it is essential to measure and monitor downhole drilling fluid properties in real-time. This enables timely action to modify fluid composition and drilling hydraulic parameters such as pump rate, to adjust downhole properties to achieve efficient drilling, and to avoid drilling problems.

In this work, we are interested in obtaining an accurate predictive model of drilling fluids HPHT rheological properties in real-time conditions. We explore various machine learning algorithms to find the most accurate model. The accuracy of the predictive model is essential at the rigsite for the drilling personnel to make the right decision regarding mud composition and drilling hydraulic parameters.

Methodology

AutoML

In various problems encountered in oil & gas, the number of records/observations is on the order of thousands or tens of thousands (rather than millions). For these relatively small data sets, different machine learning algorithms compete in terms of generalization accuracy (Shirangi et al., 2019). Application of an automated machine learning (autoML) process is therefore needed to determine the most accurate predictive model. The algorithm that we developed in this work, automates the algorithm selection and hyperparameter optimization process. This enables us to explore various algorithms such as random forests, support vector regressions, and neural networks, and for each algorithm find the hyperparameters that provide the best accuracy.

It is worth mentioning that Shirangi et al. (2019) applied autoML to predict the monthly oil production of a well in the completion optimization context, and found an ensemble approach to outperform the widely used deep neural network. This further motivates us to look beyond neural networks for obtaining the best predictive model.

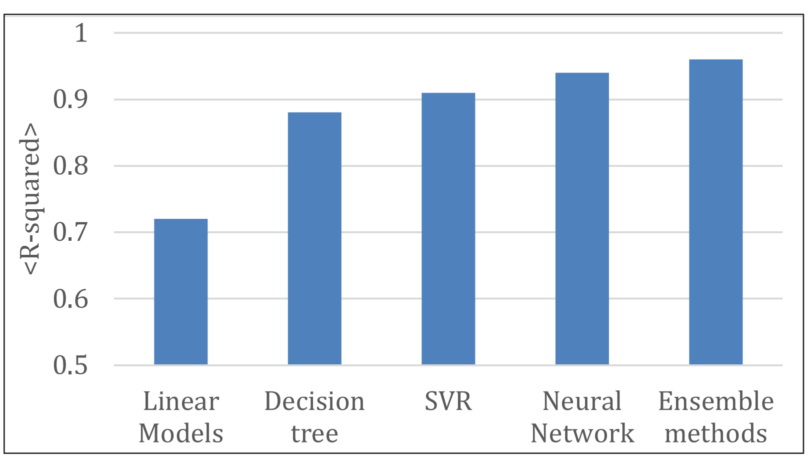


Figure 1. *Cross-validation accuracy of the best model from different algorithms*

Data Description

Data used in this work was obtained from full field fluid checks and corresponding technical lab tests to measure HPHT fluid rheological properties. The significance of this high-quality data is enormous, as tremendous cost and resources were spent to perform the lab tests, and then collect, record, and maintain the data. The value of the data, however, was not recognized until it was used in building a predictive or prescriptive model.

Results and Discussion

Our data consists of drilling fluid surface rheological properties and compositional data. After applying the autoML process to the data, we observe that an ensemble method provides the highest accuracy (**Figure 1**).

Hyperparameter Optimization and Generalization Accuracy

For every algorithm considered, the associated hyperparameters play a crucial role in generalization accuracy of the predictive model. For example, the performance of a neural network depends on the neural network architecture (number of hidden layers and the number of neurons at each layer) and the choice of the activation function. For simplicity, we use the Rectified Linear Unit (ReLU) activation function.

With autoML, we explored various network architectures to find the most accurate neural network. In this section, however, our goal is to systematically investigate the performance of a neural network for prediction of downhole fluid rheological properties. We choose the 600 reading as the target variable. We vary the number of hidden layers from 1 to 5 and the number of neurons at each layer from 10 to 220. As **Figure 2** demonstrates, there is a wide range of cross-validation scores for the cases considered (from 0.91 to 0.96). The best performance is obtained with 220 neurons and 5 hidden layers. It is also evident that the number of layers is less important than the number of neurons at each layer.

Conclusions

In this work, we developed and applied an accurate machine learning model for predicting the downhole HPHT rheological properties of drilling fluids using surface measurements and mud composition data. We developed and applied an automated machine learning process to find the best algorithm and the best associated hyper-parameters. As an example, we demonstrated that the generalization accuracy of neural network changes significantly with the network architecture.

Costly drilling problems that can affect wellbore stability may occur due to the variation in HPHT drilling fluid rheological properties. To prevent possible well stability incidents and decrease non-productive time, it is important to detect these variations in the field by using the developed ensemble method.

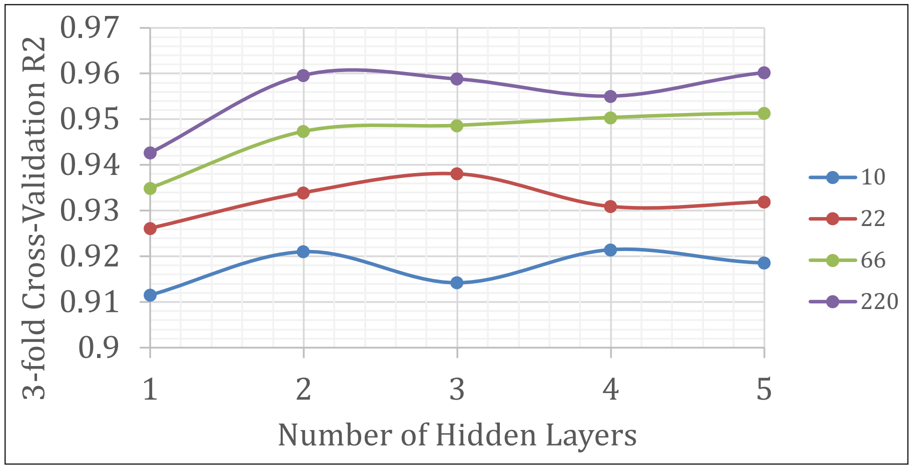


Figure 2. *Cross-validation accuracy of deep neural network versus number of hidden layers. Colors show number of neurons at each layer.*

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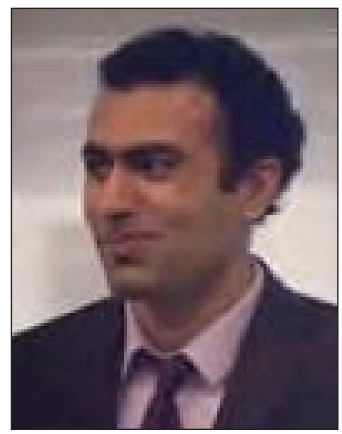
Biographical Sketch



Mehrdad Gharib Shirangi is a Senior data scientist lead at Baker Hughes (legacy GE Oil & Gas). Before joining GE, he was a PhD researcher at Stanford University. He holds BS degrees in mechanical and petroleum engineering from Sharif University, an MS degree from University of Tulsa, and a PhD degree from Stanford University. Dr Shirangi's current interests include prescriptive data analytics and digital transformation for optimal oil & gas operations.

Wednesday, November 6, 2019 | Session 2 | 2:35
Christophe Germay, **Tanguy Lhomme**
ESPLOG SA

Benefits of Continuous Data from Whole Cores for the Characterization of Unconventional Reservoirs and the Design of Hydraulic Fractures

Summary

A review of several case studies reveals the benefits of additional steps in core analysis involving continuous high-resolution sets of core data for the characterization of unconventional reservoirs and the design of hydraulic fractures. These enhanced data acquisition and integration workflows include stages such as screening and validation of standard rock mechanical tests results, and their integration with wireline logs. This enables the generation of more realistic geomechanical models and in turn better well and reservoir management decisions concerning hydraulic fracturing treatment designs. Tight calibrations of rock mechanical property predictors using continuous measurements on the core leads to more focused risk assessments and better identification of new opportunities in unconventional reservoirs.

Introduction

With extremely low permeability values, unconventional reservoirs can only be produced commercially following stimulation by hydraulic fracturing. This paper articulates observations and findings from several case studies to highlight areas for improvement in 'standard practices' for the geomechanical evaluation of unconventional reservoirs, and propose innovative solutions based on high quality, high resolution core data. We review several examples of comprehensive core analysis and rock mechanical test programs from the mapping of geomechanical properties across the target units to the optimization of hydraulic fracturing treatment designs. We discuss issues and shortcomings related to differences in resolutions between data sources, and to the use of scarce core data. We then highlight the benefits of using continuous high resolution profiles of rock properties as necessary complements to wireline logs and standard physical properties acquired on core plug samples.

Method and/or Theory

Core testing technologies described in the examples cited herein are integrated in one compact and portable test bench, which requires light logistical support and minimum sample preparation. These fast and efficient testing campaigns can be run at an early phase of the laboratory analysis program. High resolution continuous profiles of rock properties are measured on whole cores, and used to estimate geomechanical and petrophysical properties and their correlation with the mineralogical composition of tested samples, and to map geomechanical facies for further calibration of well and reservoir models at different scales;

Non-destructive tests are run on whole cores; robustness is demonstrated via repeatability. In all of the case studies described herein, the reconciliation of different types of core measurements establishes their consistency and highlights their importance in capturing fine scale reservoir heterogeneity. Also, the careful integration of core analysis results with standard wireline logs prompt some fundamental questions on the capability of some wireline tools to reliably image the complexity of these rocks, and therefore to provide a suitable and reliable basis for detailed geomechanical studies of the reservoirs.

Example 1

The first example focuses on the comprehensive acquisition of data for the diagnosis of differences in the production of several wells drilled in a US shale. An objective comparison of the data

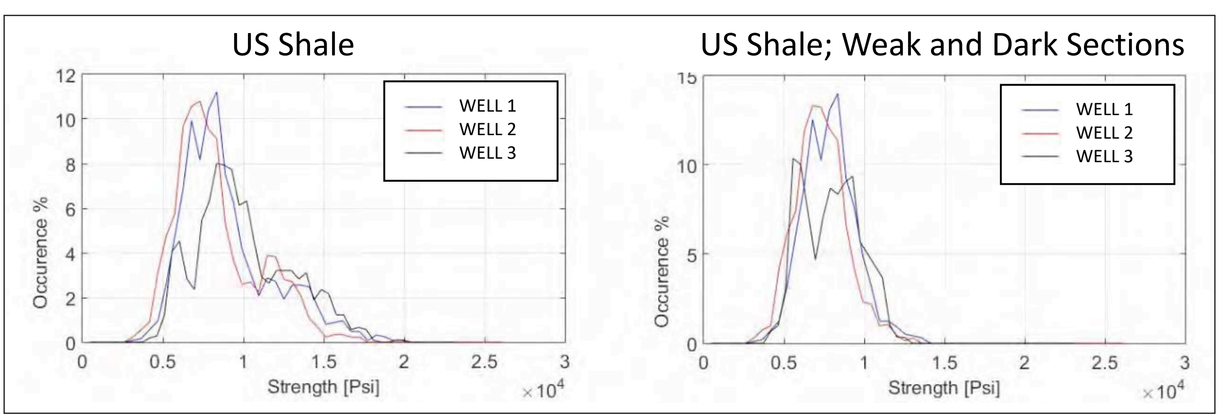


Figure 1. *Distribution of strength measured on cores from three wells.*

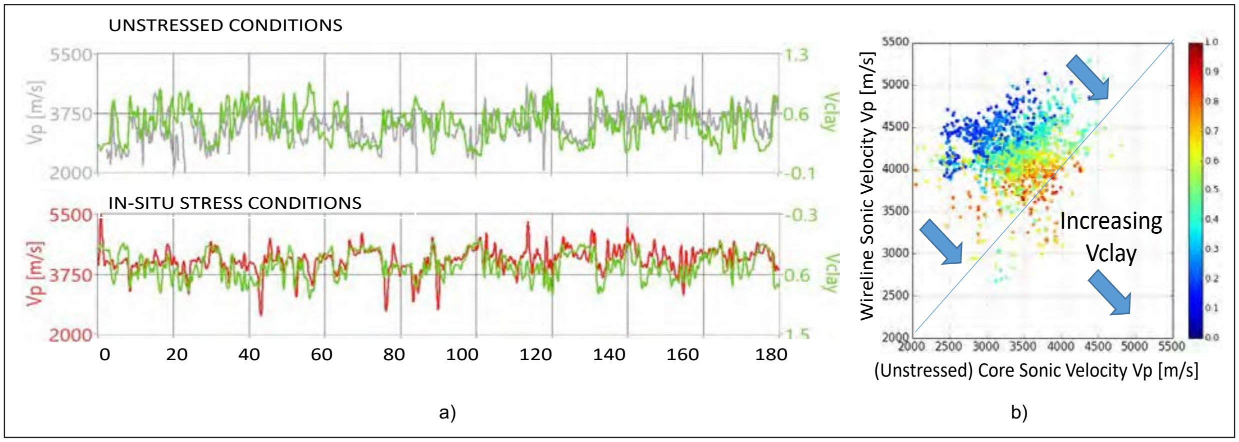


Figure 2. *a)* V_p *profiles (from core measurements in gray and from wireline in red) shown together with the* V_{clay} *profile calculated from the wireline Gamma Ray (in green). b) Cross-plot of the sonic wireline* V_p *vs.* V_p *measured on (unstressed) cores. Colours given by* V_{clay}.

acquired in these wells established the very good repeatability, limited dispersion, and therefore the reliability of the continuous core data.

Example 2

This second example (Germay, Lhomme, & Camilion, 2019) focuses on the geomechanical evaluation of an unconventional tight-gas sand reservoir of the Neuquén basin, Argentina, consisting mainly of a thick sequence of deltaic and fluvial sandstones and siltstones. A comprehensive core analysis and rock mechanical test program was conducted with the intent to map geomechanical properties of interest across the target units, in order to optimize the design of future hydraulic fracturing treatments. The reconciliation of several types of core measurements established their respective importance in capturing the contrasts between soft units and more competent formations, which could not be detected by the suit of standard wireline sonic tools. We venture an explanation for the discrepancy between wireline and core data based on the difference of mineralogy-dependent sensitivity of acoustic wave velocity to stress between hard and soft rocks. Velocity differences between soft and hard rocks exist under low confinement, but are much less pronounced under reservoir in-situ stresses.

These observations have important and significant implications for the reliability of sonic tools for geomechanical characterizations in unconventional reservoirs, for stress modeling and stress contrasts and the impact on stimulation through hydraulic fracturing. In particular, the problems of vertical containment of fracture growth, of proppant embedment, and early fracture closure relies on mapping of static elastic properties of the rock under stresses significantly less than the in situ stress state.

Conclusions

We propose a series of upgrades to standard geomechanical workflows in order to improve the geomechanical characterization of unconventional reservoirs with fit for purpose core and wireline data integration processes.

We discuss how continuity, redundancy, and robustness in core data all are essential to provide a solid ground for the planning and the quality-checking of subsequent tests. These enhancements in the internal coherence of geomechanical test results and their better upscaling with wireline logs should contribute to the building of more robust and calibrated Mechanical Earth Models for stress and strength predictions, which are critical for the adequate design of hydraulic fracturing for reservoir stimulation.

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Biographical Sketch

Tanguy Lhomme is a director at Epslog. Before joining Epslog in 2013, Tanguy worked eight years as a Reservoir engineer with Shell International, including 4 years on reservoir surveillance and enhanced Oil Recovery projects for PDO in Oman. He holds a PhD in Applied Earth Sciences from Delft University, with a research thesis on lab experiments of hydraulic fracturing and an MSc in Mining and Petroleum Engineering from the University of Minnesota, with a research thesis on fundamental aspects of rock strength testing. His current interests are in innovation for core testing and analysis, multi-disciplinary data integration for the characterisation of unconventional reservoirs.

Richard A. Schultz, Orion Geomechanics LLC; Douglas W. Hubbard, Hubbard Decision Research; David J. Evans, British Geological Survey; Sam L. Savage, ProbabilityManagement.org

Characterizing Off-Normal Occurrence and Leakage Risk at Underground Natural Gas Storage Facilities

Summary

Natural gas (methane) has rapidly become a critically important component to the energy economies of the United States and other countries. Because storage capacity in the above-ground pipeline network is insufficient to meet demand, natural gas is stored in large underground (UGS) facilities both in the US and, to an increasing extent, throughout the world. Defining a baseline for the frequency of reported and documented off-normal occurrences, including human error, process safety, mechanical or operational issues, or natural events with or without leakage, at UGS facilities is critical to maintaining safe operation and to the development of appropriate risk management plans and regulatory approaches. A Bayesian probabilistic analysis characterizes the historical occurrence frequencies. Frequencies for the three main UGS facility types (depleted oil-and-gas field, aquifer, solution-mined salt cavern) are generally on the order of 3 to 9 x 10^{-2} occurrences per facility-year, of all causes and severities. Loss of well integrity is associated with many, but not all, occurrences. Storage operators and industry regulators can use occurrence frequencies, and their associated probabilities and uncertainties, to better prioritize resources, establish a baseline against which progress toward achieving a reduction target is measured, and develop more effective mitigation, monitoring, and reduction programs in a risk management plan.

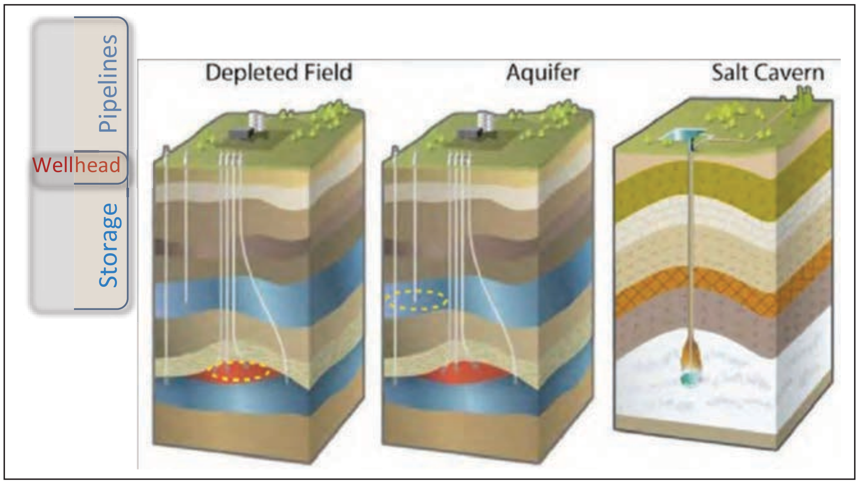

Figure 1. *Diagram showing the three main types of underground natural gas storage facilities and the wellhead separating the underground storage component from the transport (pipeline) component of the Storage and Transport sector of the midstream oil - and - gas sector (after Schultz and Vereide, 2017)*

Introduction

Natural gas (methane) has rapidly become a critically important component to the economies of the United States and other countries, providing an important energy source for industrial, commercial, and electrical generation sectors as well as for residential heating. Natural gas has traditionally served the seasonal winter-heating market. It is increasingly being called upon to help meet shorter-term peak demand in the summer-cooling market as the need for electrical generation increases (e.g., for air conditioning); to support liquefied natural gas (LNG) production; and to provide a steady and reliable backup for renewable power, such as wind and solar, which are characterized by intermittent or variable supply. Because the storage capacity in the above-ground pipeline network is insufficient to meet these demands, natural gas is stored in large underground facilities (Katz and Tek, 1981; principally porous-rock storage (depleted oil-and-gas fields and aquifers) and solution-mined salt cavern storage (**Figure 1**), both in the US and throughout the world.

In the US, the majority (~80%) of the current UGS facilities utilize depleted oil-and-gas fields. Porous-rock storage thus represents some 91% of UGS facilities in the US, with solution-mined salt caverns comprising the remainder. Approximately 14,138 injection and withdrawal wells service UGS facilities in the US, with 88% in depleted oil-and-gas facilities, 11% in aquifers, and 1% in salt caverns.

Unintentional releases of natural gas and other stored hydrocarbons, such as propane, other natural gas liquids (NGLs), and crude oil to the surface or into the subsurface environment are recognized as a challenge to the safe and reliable operation of underground hydrocarbon storage facilities. Previous work has documented off-normal occurrences at such facilities and assessed their frequency or failure mechanisms along with their degree of severity, in part to inform risk-based assessments of subsurface geologic storage of hydrocarbons and wastes. An occurrence describes any reported or documented "off-normal" issue arising during routine operations at any given facility, of any cause or magnitude of severity, that may have involved human error, process safety, mechanical or operational issues, or natural events. Occurrences may or may not have involved a loss of product containment and are variously referred to as events, incidents, accidents, or failures in other studies (Evans and Schultz, 2017). Historical databases of natural gas occurrences are commonly referred to during the design, siting, and risk assessment of underground storage facilities for carbon dioxide.

The identification and assessment of risks to product escape and loss at UGS facilities lies at the heart of risk management programs that are currently being developed and deployed throughout the gas storage industry (Folga et al., 2016; Joint Industry Task Force, 2016). Such methane releases are important to characterize and mitigate to ensure a reliable supply of natural gas to customers as well as to minimize potentially harmful discharges into groundwater or the atmosphere. Unintended releases of product from various UGS facilities have focused widespread attention in the US on the safety and reliability of these facilities, and have motivated new federal and state regulations that require risk management plans and related safety assessments (Folga et al., 2016; U.S. Department of Energy, 2016). Because risk involves some combination of occurrence, likelihood, and severity or consequence of product loss (e.g., Kaplan and Garrick, 1981), robust statistical analysis of historical occurrences constitutes a fundamental element of risk assessment and mitigation strategies.

This conference presentation will summarize a probabilistic analysis of natural gas occurrences at UGS facilities in the United States, drawn from a comprehensive database of occurrences at underground hydrocarbon storage facilities and analyzed by using a Bayesian statistical approach. This approach provides greater context and insight for decision-makers, such as public utilities, pipeline operators, investors, and industry regulators, than can approaches such as simple arithmetic means or ranges that currently find widespread use in the underground storage industry.

The dataset of historical occurrences for UGS facilities used here was described in detail by Evans and Schultz (2017) and augmented by including additional occurrences that have happened since, or had otherwise come to light. Sources of occurrences include data from industry, trade associations, government studies, academic sources, and suitably cited media coverage, resulting in an impartial database that can be considered fair and acceptable to industry, academia, and regulators.

All documented occurrences for US UGS facilities were re-examined and classified by:

- Type of storage facility
- Location of occurrence
- Primary cause
- Severity or consequence

Assessing the severity or consequence of an occurrence is a required element in defining risk (e.g., Kaplan and Garrick, 1981). Evaluating the severity of a natural gas occurrence is critical to distinguishing small, nuisance-level product issues such as may be identified from increased scrutiny or inspection frequency of facilities from those having greater degrees of severity and consequence to facility operations, regulations, and the public.

Methods

In current practice, the frequency of occurrences is quantified by dividing the total or cumulative number of recorded occurrences by the current number of facilities of a given type, or by the number of wells, times years of operation. While inventories and databases of occurrences as a function of facility type, cause, and perhaps severity provide the numerator to an arithmetic mean frequency calculation, the denominator is normally given by the total number of facilities in operation times the number of years of operation of each facility (facility-years), or by the total number of years of operation of each gas injection and withdrawal well (well-years). Mean historical occurrence frequencies can show large variability depending on the number of occurrences considered. Correspondingly, the number and types of storage facilities and wells have varied per year, contributing to a large uncertainty in the denominator of the frequency expression when used in conjunction with the cumulative number of occurrences.

Given such well-known drawbacks to the use of mean arithmetic ratios of occurrence frequency, Bayesian inversion is used in this presentation to calculate the probability of an occurrence frequency that was incompletely sampled by the historical occurrence data. In this approach, the number of occurrences is determined by a binary choice (documented/not documented), per facility-year or per well-year, corresponding to a Bernoulli trial. The resulting binomial distribution models the occurrence frequency relative to a random number of occurrences using a large number of trials. Frequencies are calculated using the BETAINV and BINOM.INV functions in Excel™.

Results and Discussion

Robust Bayesian analysis of the data suggests that occurrences from depleted oil-and-gas storage facilities have about a 0.3% probability with a maximum-likelihood frequency of about 3.52×10^{-2} occurrences per facility-year; occurrences from aquifer storage facilities have a 0.1% chance with a frequency of about 3.46×10^{-2} occurrences per facility-year, and salt-cavern storage facilities have a nearly 0% chance with a frequency of about 9.24×10^{-2} occurrences per facility-year.

Using the previous dataset of Evans (2009) as a subjective prior, the occurrence frequencies for depleted oil-and-gas and aquifer storage facilities from later datasets are consistently shifted to smaller frequencies but are increased in probability. In general, values of occurrences that utilize previous datasets as a Bayesian prior tend to provide more reliable estimates for occurrence frequencies (i.e., higher probabilities with narrower distributions and, in turn, smaller uncertainties) than do data analyzed in isolation from previous historical data. The Bayesian analysis with nonuniform prior implies that occurrence frequencies are less than expected, and the UGS facilities correspondingly safer, than would be concluded based on occurrence frequencies computed by using the simple arithmetic means.

Conclusions

Occurrence rates for the three main storage facility types (depleted oil-and-gas, aquifer, solution mined salt cavern storage) are generally in the range of 3 to 9 x 10^{-2} occurrences per facility-year, of all causes and magnitudes of severity or consequence, which is larger than has been previously reported. Significantly smaller occurrence frequencies are found for above-ground versus belowground (subsurface) occurrences, for those occurrences in the subsurface that reach the ground surface, and for occurrences having increasing severity or consequence magnitude.

Occurrences from underground natural gas storage in depleted oil and gas fields consistently exhibit the largest probabilities and smallest uncertainties, and smallest occurrence frequencies, per facility year than do occurrences associated with either aquifer or salt cavern storage. Within the subsurface, leakage occurrences associated with a loss of well integrity have a higher frequency than those associated with a loss of subsurface integrity. However, leakage occurrences that reach the surface are more commonly related to a loss of well integrity, consistent with the current focus on improving well integrity in association with underground natural gas storage. ■

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Biographical Sketch

Dr. Richard A. Schultz is a geologist specializing in the geomechanics of faulted overburden and reservoir systems. He is also manager and principal consultant with Orion Geomechanics LLC of Cypress, Texas and co-founder and partner with Integrity Subsurface LLC. Previously he was Senior Research Scientist at The University of Texas at Austin, Principal Geomechanicist with ConocoPhillips, and Foundation Professor of Geological Engineering and Geomechanics (now Emeritus) with the University of Nevada, Reno. He received his BA degree in Geology from Rutgers University, MS degree in Geology from Arizona State University, and PhD degree in Geology from Purdue University. Dr. Schultz is a member of the Interstate Oil and Gas Compact Commission, a Fellow of the Geological Society of America, a licensed Professional Geologist in the State of Texas, and was an instructor of State oil and gas regulators with TopCorp.

Abstracts

Oral Presentations
Day Two

November 7, 2019

Southwestern Energy
Spring, Texas

Ahmad Ghassemi, Reservoir Geomechanics & Seismicity Research Group, The University of Oklahoma

Geomechanics of Unconventional Hydraulic Fracturing: Fracture Clusters, Complexity, "Frac-Hits", and All That

Summary

Shale reservoirs have geological and geomechanical characteristics that pose challenges to accurate prediction of their response to hydraulic fracturing. Experience shows stimulation often results in a stimulated volume with some degree of complexity. Currently, mechanisms that generate the fracture systems are not completely understood, and are generally attributed to low in-situ stress contrast, rock brittleness, shear reactivation of fractures and their propagation, and textural heterogeneity. This paper will discuss issues pertaining to the development of a stimulated volume through interactions of multiple hydraulic fractures with natural fractures and each other based on geomechanical concepts and principles. Laboratory investigations and robust large-scale numerical simulations of hydraulic fracture propagation in mudstones will be presented. The effect of in-situ stress conditions and different staging techniques will be explored in the presentation. Finally, issues related to re-frac and well interference will be discussed with particular reference to "frac hits", using advanced, fully-coupled 3D poroelastic simulations.

Introduction

The geometry and propagation direction of a hydraulic fracture mostly depend on the drilling direction of horizontal wells and the in-situ conditions, as well as on the rock mass fabric features. 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 reservoir characteristics including the formation pore pressure variations. It is very likely the stimulated volume results from 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", and can in turn lead to tensile or shear crack propagation. Improved understanding of these processes and design optimization can benefit from laboratory experiments and numerical simulations which are able to capture the real physical mechanisms. Only a few well-controlled laboratory experiments have been carried out to help understand the physical mechanisms, and often frac models make significant short-cuts and oversimplifications of important geomechanics principles. In the following sections, fundamental laboratory experiments are presented first to illustrate key stimulation mechanisms. Then, advanced, physics-based and efficient fracture modelling is presented to study and explain some important field-observed phenomena, and to illustrate fundamental aspects of multiple hydraulic fracture propagation, and fracturing of in-fill wells with emphasis on the so-called "frac hit" issue.

Shear Slip & Fracture Propagation: Contributions to Reservoir Stimulation

Encouraging shear slip on natural fractures and or bedding planes has long been viewed as a reservoir stimulation mechanism. However, the concept has only been convincingly illustrated recently using laboratory experiments. Also, the possibility of the fracture propagating under injection-induced shearing at pressures below the minimum in-situ stress has not been well understood. In fact, until recently no realistic injection experiments were carried out at representative stress and injection conditions. Here, we provide a summary of experiments to illustrate these fundamental stimulation mechanisms that often occur simultaneously.

First, a cylindrical Eagle Ford shale sample having a single rough fracture is used to conduct shear tests under representative triaxial stress. In the test, the fracture slip and dilation is induced by elevating injection pressure. As a result, significant flow rate enhancement is achieved by the dilatant fracture slip (Ye et al., 2018) as shown in **Figure 1**.

The shear slip of pre-existing fractures could also lead to a stress intensity increase at the fracture tips, causing them to propagate to form an interconnected fracture network. To illustrate this for the first time under triaxial stress injection, a new experiment was designed. A cylindrical sample of Eagle Ford shale containing two embedded fractures was used to perform the triaxial-injection test. With the elevation of the injection pressure, a highly conductive fracture network was created by the connection of the newly propagated cracks and the pre-existing fractures, resulting in a remarkable enhancement of flow rate/permeability.

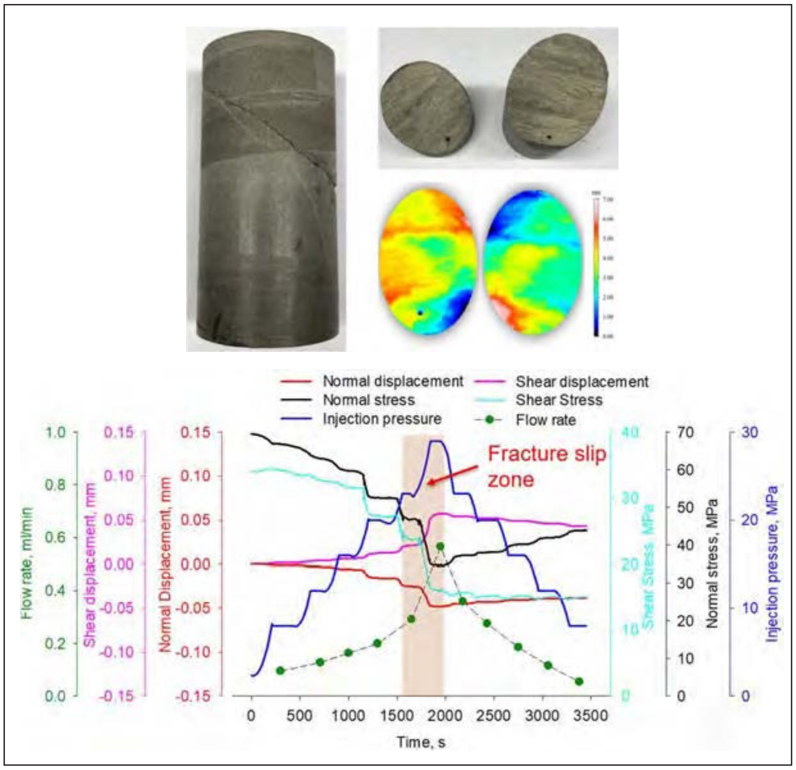


Figure 1. *Top: Eagle Ford shale having a single rough fracture. Right: the fracture surfaces and the relevant 3D scanning contours. The maximum surface relief is 7 mm and the corresponding JRC values is 12.35; bottom: flow, pressure, stress, and deformation data (Ye et al., 2018).*

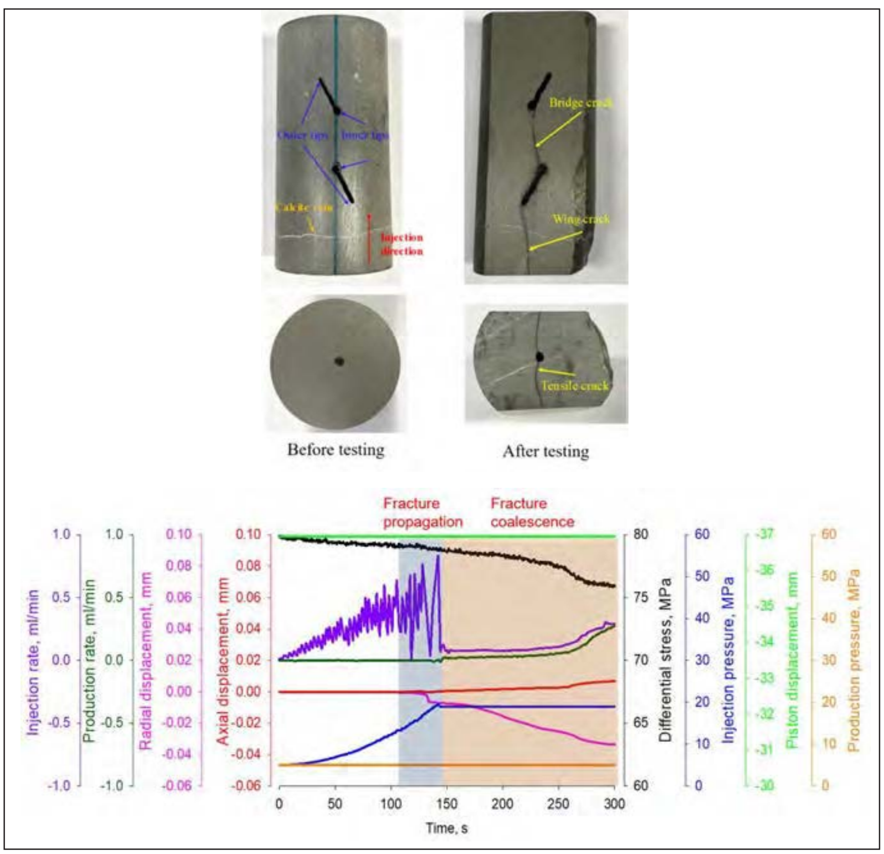


Figure 2. *Injection-induced fracture propagation test on Eagle Ford shale. Left: before testing. Note wing crack propagation from pre-existing fractures (Ye & Ghassemi, & Riley, 2018).*

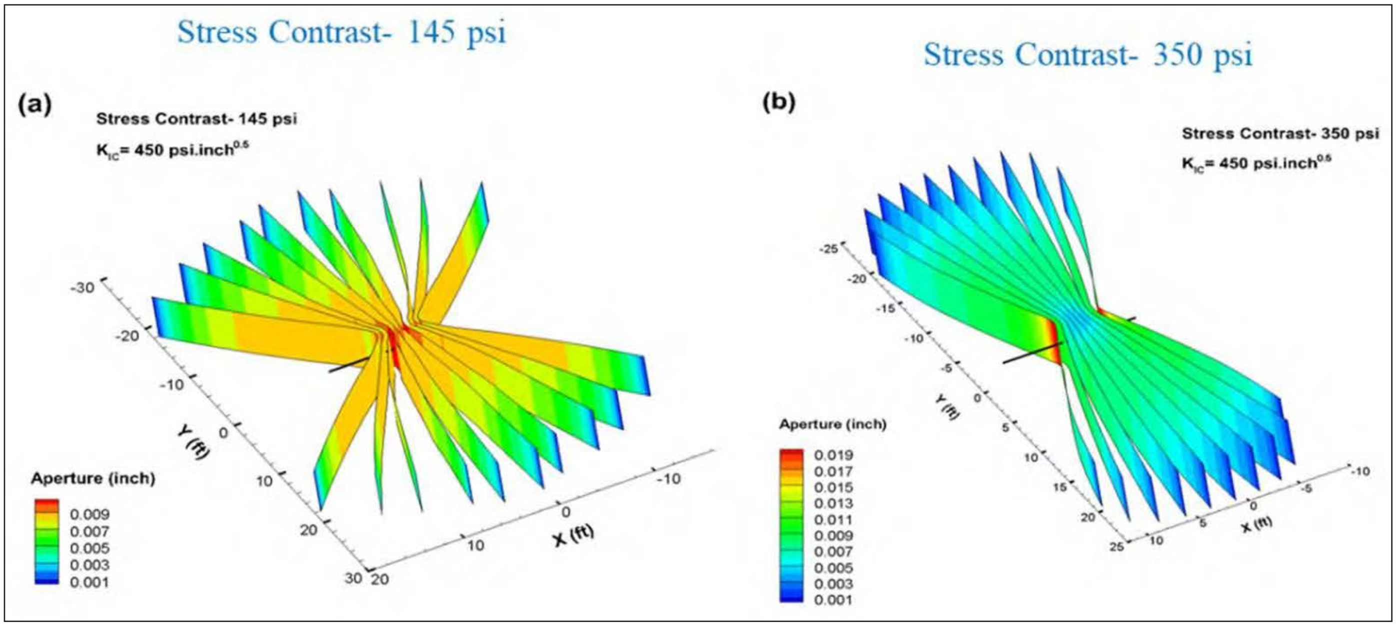


Figure 3. *Effects of in-situ stress difference on closely-spaced fracture propagation from a single perforation cluster (Sesetty and Ghassemi, 2018).*

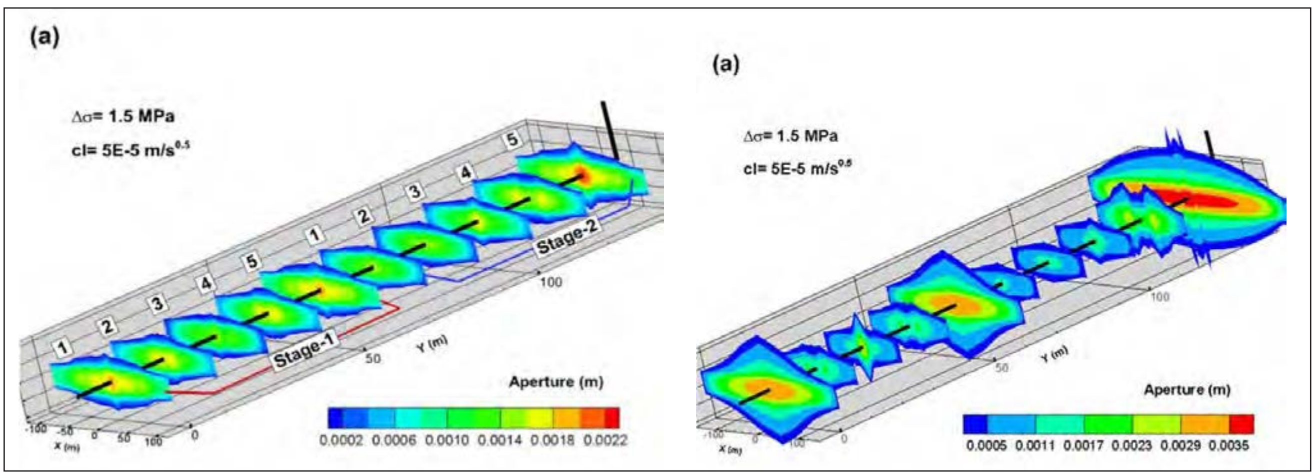
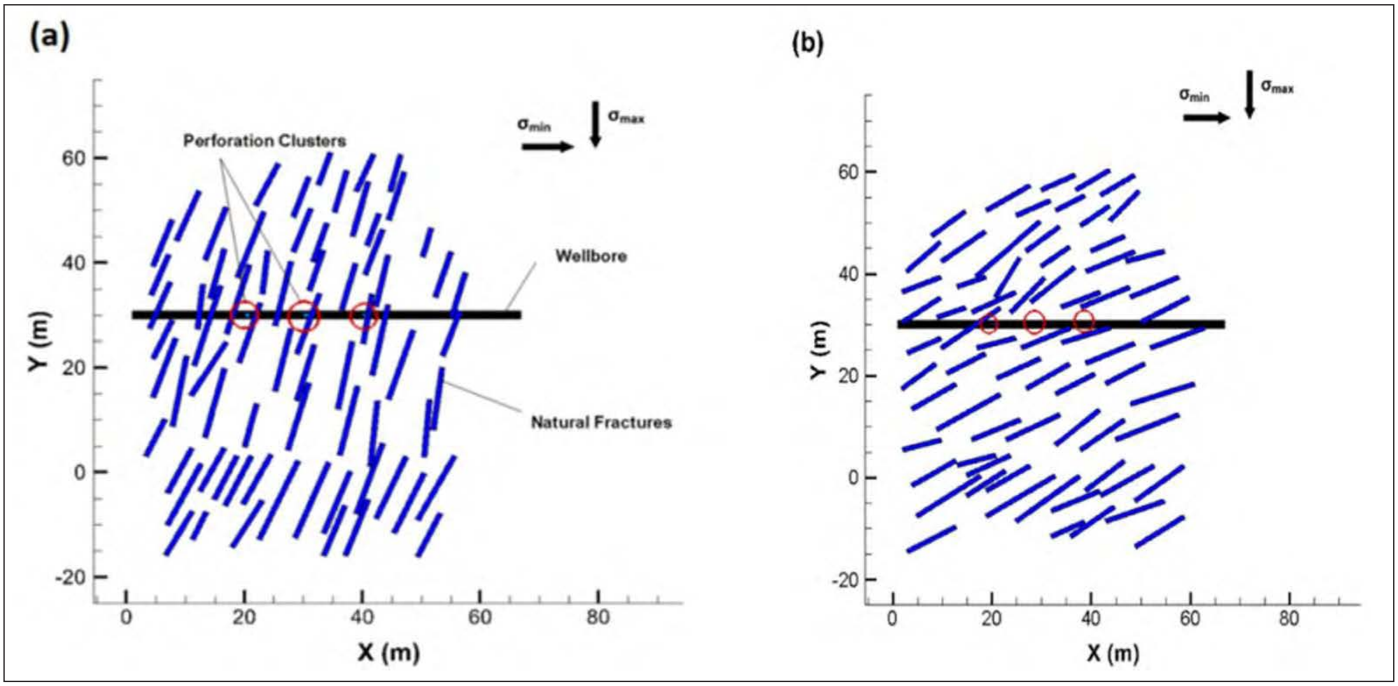


Figure 4. *Fracture geometry after 10 and 17 minutes of pumping. Some heel bias; largest width and height among outer fractures of Stage 2 (max. of 80 m above the injection point) (Sesetty and Ghassemi, 2019). Some inner fractures also show notable height growth because of the low stress contrast (Kumar and Ghassemi, 2017) between the payzone and the over/underburden.*

Insights from Numerical Simulations of Multi-stage Fracturing

Tightly-spaced Fracture Clusters: The HFTS core data has shown the occurrence of closely-spaced sub-parallel hydraulic fractures. We have studied the condition conducive to their formation and the impact on net pressure (Sesetty and Ghassemi, 2018, 2019). In-situ stress conditions, stress shadowing, fracture toughness, stress differential, and pumping rate (for a give viscosity) show to be critical parameters. Large injection rates and stress differential encourage parallel growth of multiple closely spaced hydraulic fractures. Perforation friction also plays a critical role. **Figure 3** illustrates the effects of in-situ stresses on multiple fracture geometries.

Fracture height growth and heel bias are of concern in multi-stage horizontal well fracturing. These occur as a result of the interaction of fracture-to-fracture and stage-to-stage stress shadow effects and the strength of the stress barrier above and below the target zone. Consider, a two stage treatment from the toe towards the heal (**Figure 4**). In this example case, the barrier stress is set to 1.5 MPa. At the end of pumping, the hydraulic fractures seem to have grown somewhat uniformly (**Figure 4**), however, as can be seen the heel-side fracture of the Stage-2 is longer and has more height growth. Heel bias is also evident in the width distribution i.e., higher apertures occur in the Stage-2 fractures on the heel side. Fracture height is the highest among the outer fractures with fracture 5 in Stage-2 having the maximum height growth of 80 m above the pumping level. It can also be seen that some interior fractures show notable height growth; this is caused by the low barrier stress.



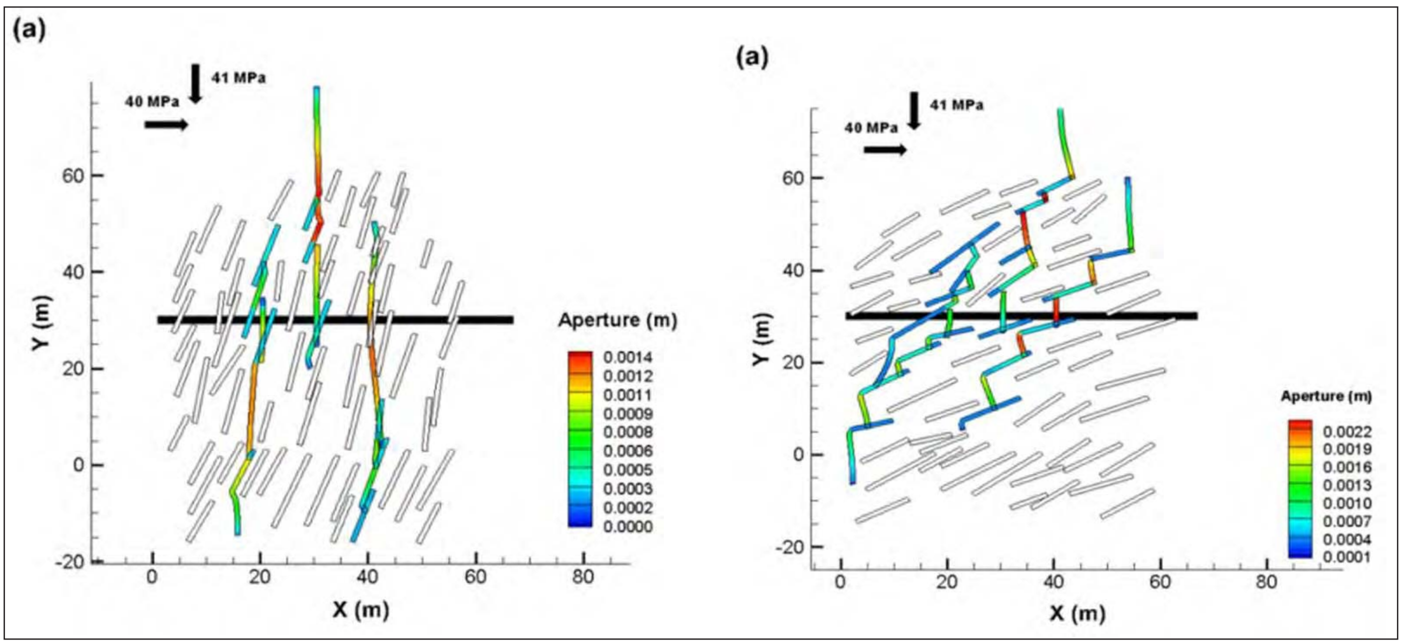


Figure 5. *Fracture networks N-1 and N-2 used in numerical simulations. The height of NFs is 30 m. Three perforation clusters are placed at 10 m spacing. Principal stresses are oriented in X-Y directions. Pre-existing natural fractures are presented in blue (Sesetty and Ghassemi, 2019). The network on the left shows lower wing growth but broader stimulated width. The left network shows a more "planar" outline.*

Fracture Network Complexity & High Net Pressure: Consider the stimulation of two fracture networks from 3 perforation clusters (**Figure 5**). Perforation location is indicated by red circles along the wellbore in **Figure 5**. The in-plane differential stress in this example is 5 MPa with 40 MPa minimum principal stress and water is pumped at 30 bpm. Assuming negligible fluid loss into the rock matrix, the natural fracture geometry, aperture distribution, pressure distribution, shear displacements and status of all elements at the end of the simulation are shown in **Figures 5** and **6**. Figure 5 shows hydraulic fracture growth is predominantly north-south. Hydraulic fracture is 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 fracture network that opened against the minimum insitu stress. Fracture wings emanating from the natural fractures tend to have higher opening, however the parent natural fractures have very restricted opening because higher compressive normal stresses act on them. The resulting net pressures are shown in **Figure 6**. It is interesting to note that the net pressures are not very high so that unfavourable natural fractures may not necessarily be causing the field-observed net pressures.

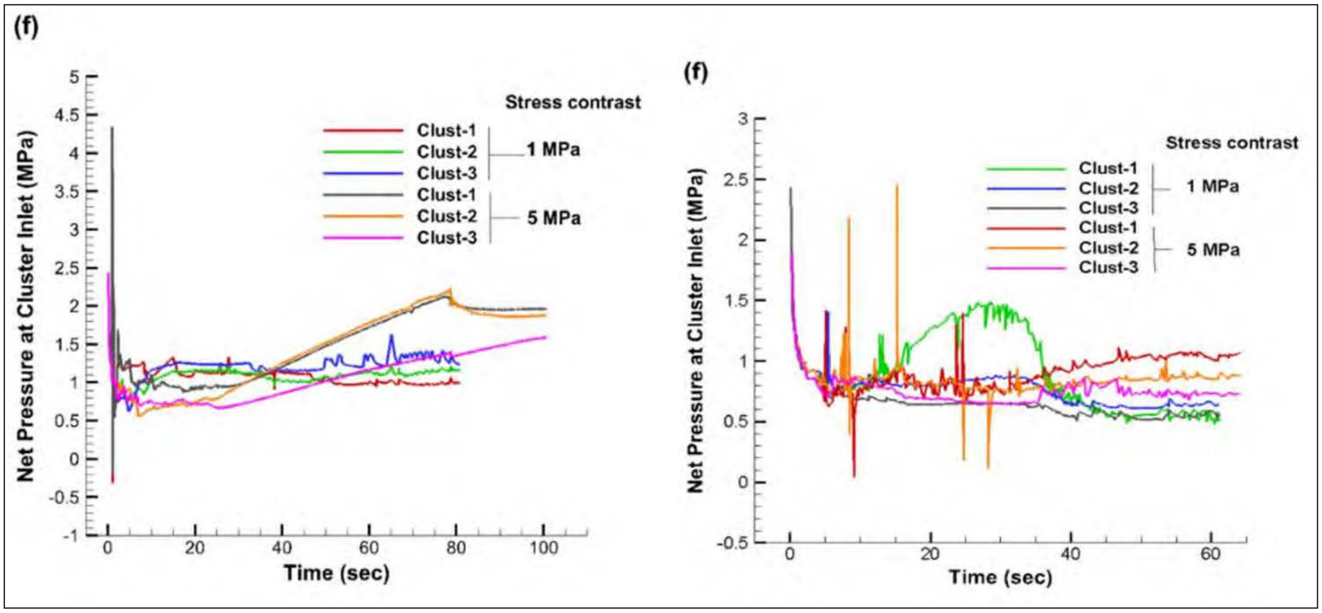


Figure 6. *Net pressure for different networks under different stress differentials, (Sesetty and Ghassemi, 2019). HF/NF coalescence alone cannot explain the very high net pressures often observed in the field.*

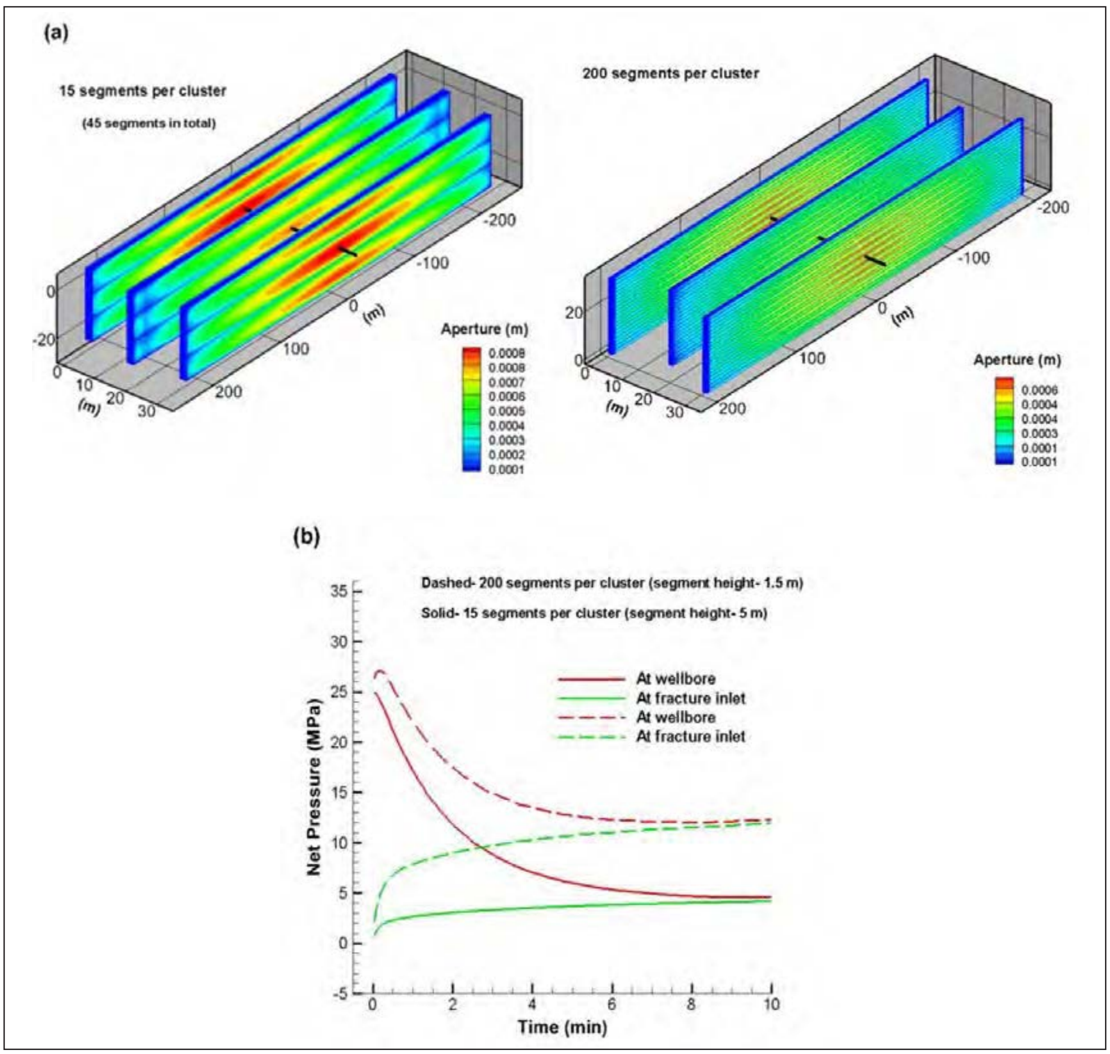


Figure 7. *Simultaneous propagation of multi-stranded fractures from three perforation clusters: (a) 5 segments per cluster with segment height of 10 m; (b) 200 segments per cluster with segment height 1.5 m. Net pressure for the case of hydraulic fracture segmentation. Clearly more realistic net pressures are obtained when the hydraulic fracture breaks into segments as it grows upwards (Sesetty and Ghassemi, 2019).*

As shown by Sesetty and Ghassemi (2019) fracture segmentation along the height is a major contributor to excessive net pressure (see **Figure 7**).

Poroelastic Effects and "Frac-Hits"

Well-to-well interference or communication between a primary production well (or "Parent" well) and the in-fill well (or "child" well) is one of the main concerns in horizontal wells refracturing, because it results in productivity reduction. Many field observations have demonstrated that the in-fill well fractures have a tendency to propagate towards the primary well resulting in well-to-well interference or the so-called "frac-hit" issues. A geomechanical modeling and analysis is presented herein to better understand the problem of "frac-hits" in horizontal well refracturing and to assess solutions design for it. The modeling is based on the fully coupled 3D model "GeoFrac-3D" with the capability to simulate multistage fracturing of multiple horizontal wells. To illustrate the issues and the role of poroelastic stress, consider the production from parent well fractures are carried-out at a constant bottomhole pressure (BHP) of 10.5 (MPa) for 2 years See Kumar et al., 2018). The reservoir pore pressure distribution is shown in **Figure 8a**, which demonstrates an ellipsoidal depletion zone formed around the production fractures. The reservoir pore pressure is decreased to 12.0 (MPa) in the depletion zone.

The impact of reservoir depletion on the total horizontal stress component σ is shown in **Figure 8b** indicating a decrease of 9.3 (MPa) (from in-situ value of 54.30 to 45.0 MPa) in the vicinity of parent well fractures. The effect on the total horizontal stress component σ is shown in **Figure 8c**, which shows that its value has decreased to 46.0 (MPa) in the depletion zone. **Figure 8d** shows that the vertical stress σ is decreased to 64.0 (MPa) from 72.96 (MPa) in the depletion zone.

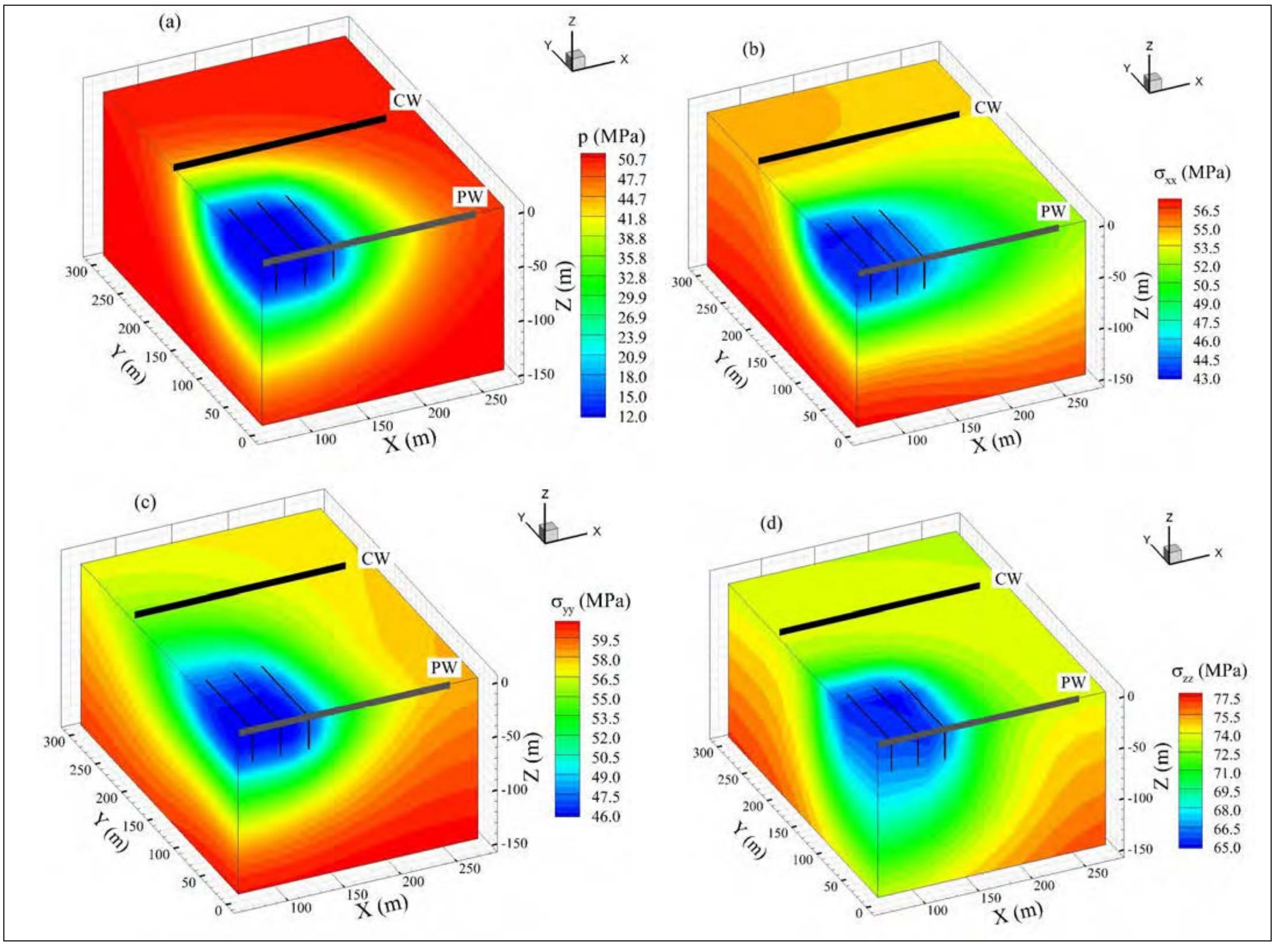


Figure 8. *A 3D visualization of the reservoir pore pressure and total stress changes around a "Parent" and "Child" well system after 2 years of depletion; (a) pore pressure, (b) stress component σ , (c) stress component σ , (d) σ . The pore pressure depletion zone is ellipsoidal shape around the production fractures. 1/8th of the reservoir volume is shown. In-situ reservoir pore pressure and stresses at the wellbore level are p = 50.6 MPa, σ = 73.12 MPa, σ = 57.72 MPa, σ = 54.3 MPa (compression is positive).*

To study the possibility of a fracture hit, consider the child well hydraulic fracture near the parent well. The created fracture geometry and its location in the reservoir are shown in **Figures 9a** and **9b**, respectively. The in-situ horizontal stress contrast in this case has a relatively low value of 3.42 (MPa) at the wellbore level; hence, after 2 years of the production, a significant stress reorientation is observed (see, **Figure 9b**). In this case, the infill well fracture has asymmetric growth towards the production well.

Due to significant reorientation of the local maximum principal stress near the parent well fracture tips, the child well fractures curve to avoid the parent well fracture tips. Beyond the parent well fracture tips region, the child well fractures turns towards the parent well with potential communication with it.

The impact of re-pressurization of the parent well is shown in **Figure 10**. It can be seen the attraction of the child well fracture towards the parent well has been resolved. However, upward growth can occur and needs be considered in planning stacked wells.

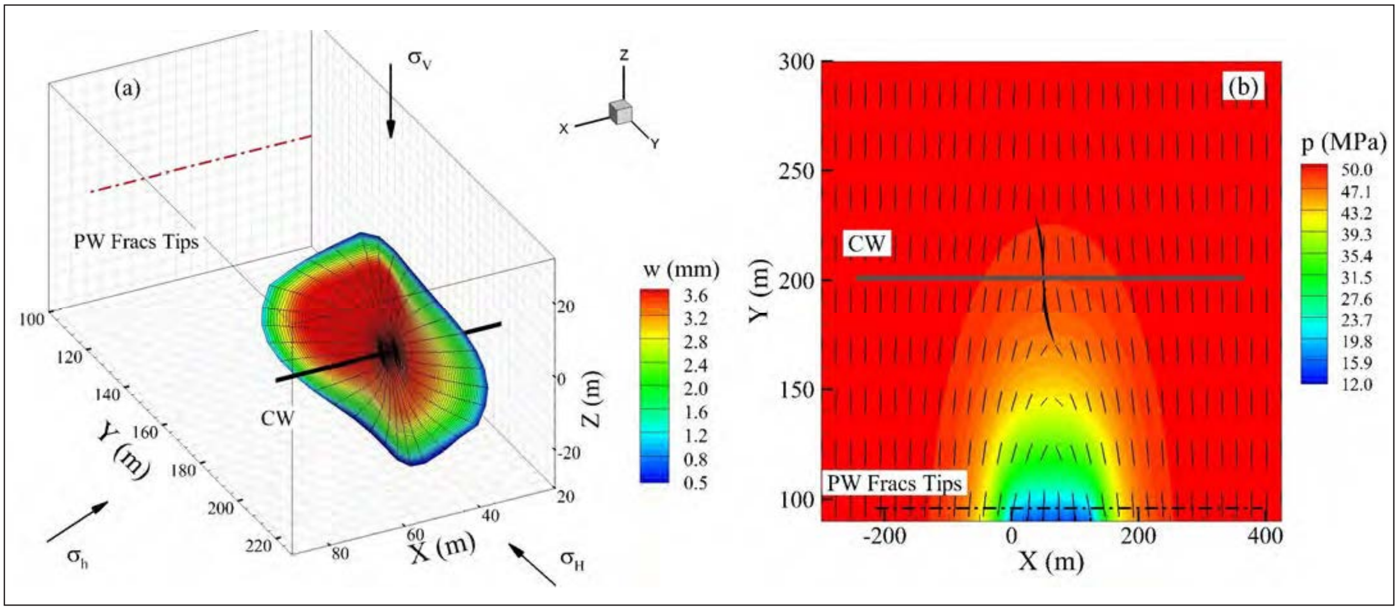


Figure 9. *Fracture propagation from a child well before re-pressurization of the production well. (a) hydraulic fracture geometry, (b) plan-view of the propagated fracture. Fracture shows asymmetric growth towards production well and also in the vertical direction (i.e., z-axis).*

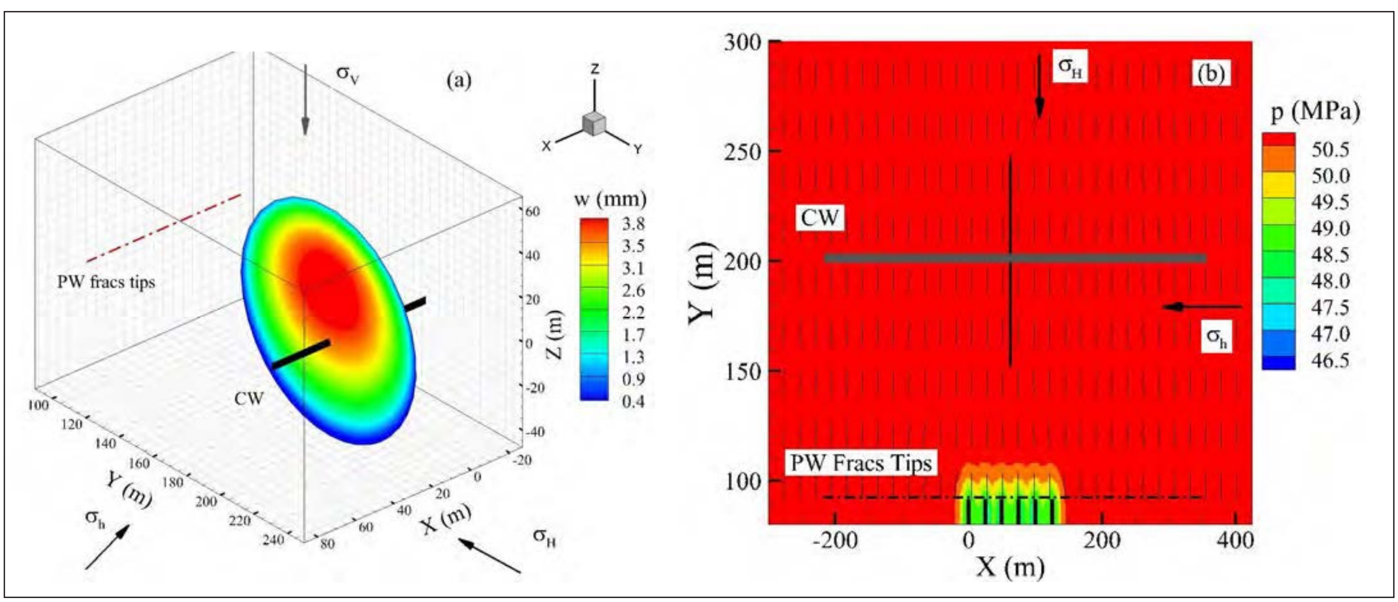


Figure 10. *Hydraulic fracture propagation from the child well after re-pressurization via the production well hydraulic fractures (normal stress regime); (a) fracture geometry, (b) plan-view of the propagated fracture. The Child well fracture shows symmetric growth towards production well and asymmetric growth in the vertical direction (i.e., z-axis) due to in-situ stress gradient.*

Conclusions

Several numerical examples have been considered to study the effect of fracture spacing and geomechanical parameters on stimulation. For a given pumping rate and viscosity, perforation orientation (and friction), spacing among fractures, and stress anisotropy show 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. Depletion induced pore pressure and stress state changes have strong effects on child well fracturing. The production from the parent well leads to a high risk of "frac-hits" or well communication. Simulations show if the parent well is pressurized before the child well fracturing, the issue of "frac-hits" can be mitigated. Most re-fracturing simulation models are two-dimensional so they cannot assess the impact of re-pressurization on height growth. It is shown here that height growth potential is enhanced by parent well pressurization and should be considered in stacked well systems. ■

Acknowledgments

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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 geothermal & petroleum reservoir development. He has been working on hydraulic fracturing and high-temperature rock mechanics research for the past 25 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.

Terry Palisch and **Souvik Mukherjee**
CARBO Ceramics and Technology

Estimation of Propped Fracture Geometry Using Electromagnetic Geophysics

Summary
Knowledge of the extent and nature of proppant distribution in hydraulic fractures helps optimize production efficiency in unconventional hydrocarbon reservoirs. Conventional geophysical imaging techniques have not been successful in discerning the subset of "stimulated fractures" (observed in microseismic) that have received proppant. Recent advances where proppant is coated by special materials to enhance its electrical conductivity without compromising its geomechanical characteristics, can produce a detectible geophysical target utilizing novel borehole to surface electromagnetic methods. This abstract/presentation highlights the development of this technology and presents results of the application of this method in a well in the onshore STACK play in Oklahoma, USA. Application of complementary techniques including surface pressure monitoring and production history analyses of an existing producing well in the area, corroborate the first order dimensions of propped fracture half-length and height determined using the electromagnetic method. These results highlight the considerable promise of the technology for addressing key questions on propped fracture geometry, to help operators plan for efficient well and cluster spacing as well as provide other benefits.

Introduction
Utilization of electromagnetic (EM) geophysics to image propped fracture geometry has been a popular idea in the current decade. The first industry scale field trial was performed in a Bone Springs formation well in the West Texas Delaware Basin (Palisch 2016). Encouraging results led to more field trials in the Pennsylvania Marcellus (Palisch 2018) and the STACK in Oklahoma (Haustveit 2018). These trials validated key conclusions regarding propped fracture geometry, and helped improve efficiency of the method for wider commercial applicability. The results of a recent field trial in the STACK play in Oklahoma will be presented and are fully documented in a recent URTeC paper (Haustveit 2019).

Key objectives for this project were:
1. Evaluate the impact of depletion on proppant geometry/asymmetry,
2. Compare the propped height in two different Meramec landing zones to guide well spacing and staggering decisions
3. Test a mixed blend of electrically-conductive proppant (ECP) with white sand to evaluate the potential to decrease the cost for future tests.

Method
The technology for determining propped fracture geometry is based on acquisition of two sets of geophysical electromagnetic data: a baseline survey conducted before placement of the electrically conductive proppant (ECP) via the fracturing treatment, and a second set of acquisition measurements after the insertion of ECP.

Acquired data is processed using several geophysical techniques and culminates in a constrained least squares based optimization known as parametric inversion (Aghasi 2011), to determine propped fracture location, orientation, and geometry. Details are available in Haustveit (2019) and Mukherjee (2019).

Results and Discussion
In-situ stress uncertainty, and other factors yield multiple inversion outcomes resulting in varying estimates of fracture length, height, and width. A "best fit" inversion was obtained yielding a 5% misfit and yielded the fracture dimensions shown

	Well 2H		Well 3H	
	Frac 1 (heel-side)	Frac 2 (toe-side)	Frac 1 (heel-side)	Frac 2 (toe-side)
Propped Half-Length (ft)	364	259	123	131
Propped Height (ft)	132	50	72	50
Max. Width (in)	0.29	0.04	0.29	0.02
Propped Fracture Volume (ft^3)	1216	43	224	10
Easting Offset (ft)	-12	-2	-2	-1
Depth Offset (ft)	70	15	33	6
Imaged Fraction of Total Proppant Pumped (%)	76%		14%	

in **Table 1**. Proppant growth was observed downward (below the wellbore) and towards the parent well. Additionally, a semi-quantitative combination of field diagnostics and laboratory experiments provide likelihood of individual results being reflective of true subsurface fracture geometry. Together, these estimates yield a cumulative distribution function "heat map" highlighting likely proppant distribution, and will be shown in the presentation.

Conclusions

A novel electromagnetic method for determining propped fracture location and geometry has been developed and deployed safely and successfully in multiple field trials. The current study provided the operator key insights on depletion effects of parent wells on bi-wing fracture growth in child wells, as well as proppant settling and stress shadowing impacts. Additional learnings on proppant–fracture fluid interactions, well landing location, and other important issues have demonstrated the potential to impact the planning of future wells in this area.

Acknowledgments

The authors thank Devon Energy (especially Kyle Haustveit) and CARBO Ceramics (especially Wadhah Al-Tailji) for permission to present this work. Technical contributions from members of Computational Geosciences Inc (CGI) and Zonge Geophysical International in making this work possible are also acknowledged.

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Biographical Sketches

Terry Palisch has been the Global Engineering Advisor at CARBO Ceramics for over 15 years, where he is involved in the technical support for both existing and new product development, and advises clients on completion practices, particularly in relation to fracture stimulation. He began his engineering career with ARCO Oil & Gas, after graduating with a BS in Petroleum Engineering from the University of Missouri-Rolla. He is active in SPE, and is the current SPE Completions Technical Director.

Souvik Mukherjee has been CARBO Ceramics' QUANTUM product champion since 2017. He oversees the development and application of geophysical technology within CARBO. Prior to joining CARBO, he worked for Shell Exploration and Production Company since 2008 and graduated from Texas A&M University with a PhD in Geophysics in 2010. He is a senior geophysicist with over 12 years of experience in the oil and gas industry and is well cited for his technical contributions within and outside the geophysical community.

J. Andres Chavarria
OptaSense, a QinetiQ company

Near and Far Field DAS Diagnostics for Unconventional Reservoir Monitoring

Distributed Acoustic Sensing (DAS) data is used by various disciplines during unconventional reservoir completions monitoring. The opportunity of distributed sensing is its ability to lower the overall life-of-well costs by providing measurements with less interventions that can be used by both geoscience and petroleum engineering. Fiber-optic DAS sensing is a dynamic sensing system that is normally used to measure strain on a fiber-optic cable. DAS can be used as a diagnostic tool to better understand the completions program using a broadband set of measurements. These measurements include low frequency temperature and strain, mid frequency seismic and microseismic, and high frequency acoustics for injection monitoring.

Measurements conducted with DAS can be performed in the far field or the near field, e.g. fiber-optic deployed in treatment wells. Here we present how near field DAS is a diagnostic of the fluid and proppant allocation during a stage, as well as a tool to determine isolation issues in real time during the hydraulic fracturing treatment. By using nearby monitoring wells we also show how the far field response can be used to characterize fracture events, represented by their microseismic event radiation and by their strain response during the duration of the treatment. We show how these various diagnostics can provide value, often in real time, to the decision process in complex completions programs.

Biographical Sketch

J. Andres Chavarria is currently the Technical Director for Oilfield Services at Optasense. He previously held various management and geophysical processing roles at SR2020, Vialogy and Conoco. He has 20 years' experience with a focus on borehole geophysics. For the past five years his focus has been on fiber optic sensing for oilfield monitoring. Andres holds PhD and Engineering degrees in Geophysics.

Thursday, November 7, 2019 | Session 3 | 10:15
Robert Bachman, CGG Services (U.S.), Inc.;
Kirby Nicholson, Perpetual Energy Inc.;
Robert V. Hawkes,Trican Well Services Ltd.

Early Warning Systems – Using PTA Analysis of DFITs to Understand Complex Hydraulic Fractures and Optimize Treatment Designs

This paper outlines methods to characterize hydraulic fracture geometry and optimize full-scale treatments using knowledge gained from Diagnostic Fracture Injection Tests (DFITs) in settings where fracturing pressures are high.

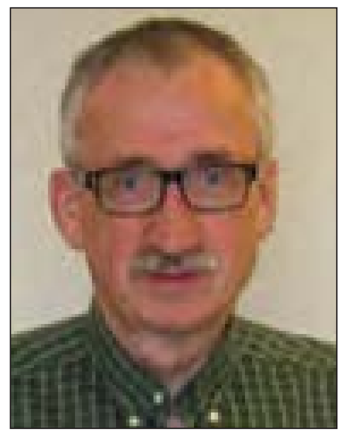
Hydraulic fractures, whether created during a DFIT or larger scale treatment, are usually represented by vertical plane fracture models. These models work well in a relatively normal stress regime with homogeneous rock fabric where fracturing pressure is less than the Overburden (OB) pressure. However, many hydraulic fracture treatments are pumped above the OB pressure, which may be caused by near well friction or tortuosity but may also result in fractures both in the vertical and horizontal planes.

Bachman et al. 2012 advanced the Pressure Transient Analysis (PTA) technique for DFIT analysis, which includes the identification of flow regimes useful for understanding fracture geometry and closure behavior beyond that available from other analysis techniques. In this paper DFITs from the Duvernay, Montney, and upper Cretaceous formations of Western Canada are analyzed using the PTA analysis method. Early-time flow regimes and pressure gradients present between Instantaneous Shut-In Pressure (ISIP) and the 3/2-slope Nolte flow regime are investigated to build on case histories of DFIT derived fracture geometry interpretations presented in Nicholson et al. 2017 & Nicholson et al. 2019.

Strategies for picking ISIP and distinguishing between friction/tortuosity versus horizontal plane fractures are proposed. Generalized conceptual fracture geometry models are tabulated for a variety of stress regimes, rock fabric, and fracture propagation pressure scenarios.

Analysis of ISIP, friction/tortuosity, and early flow regimes identified in the DFIT PTA analysis method, against the background of rock fabric and stress setting, are useful to design full-scale fracturing operations. A DFIT may help identify potentially problematic horizontal plane fractures, and predict high fracturing pressures or screen-outs. Fluid system designs can be adjusted to mitigate some of these effects using the intelligence gained from the DFIT early warning system.

Biographical Sketch



Bob Bachman is a Reservoir Engineer with CGG's GeoConsulting Group in Calgary. He has 40+ years consulting experience working around the world in all areas of reservoir engineering. He has also been involved in the design and analysis of hydraulic fracturing treatments since the 1980's. Current geomechanics research is focused on the interpretation of DFIT's, and how they affect treatment design and subsequent production performance.

Prior to joining CGG, Bob spent most of his career at two employee owned consulting companies, Taurus Reservoir Solutions and Simtech. He attended the University of Manitoba and received a B.Sc and M.Sc in Civil Engineering. He has received technical merit awards from both the Canadian and Calgary SPE sections.

Tony Settari and Dale Walters
CGG

Integrating Geology and Geophysics into Engineering Workflows to Enhance Unconventional Production

In traditional conventional oil and gas reservoirs the role of the geoscientist and engineers has been very defined and distinct between the two fields, with the role of the geoscientist to locate and drill potential reservoirs and the engineer's role to generate production. In the past once the discovery has been made there is generally little interaction between the geoscientist and the engineering group once production begins. With the advent of lateral wells and hydraulic fracturing of unconventional reservoirs for oil and gas recovery, there is a strong argument that there is now a role for geoscientists (geologist, petrophysicist, and geophysicist) during the completion and production phase, which has traditionally been the domain of the engineers. However, the limited interaction between the geoscientist and engineering groups in many operating companies in the past has meant many geoscientists don't speak the language of engineers and vice versa, most engineers do not understand the language of the geoscientist.

In this presentation we discuss a series of case studies completed with an integrated geoscience and engineering team on various unconventional reservoirs throughout mainland United States. The case studies discussed in this presentation provide examples of how the geoscientists have provided input into engineering outcomes by adjusting the "language" they are using. Examples show how geological and geophysical outputs have been successfully used to provide data to better drill and complete wells, capturing variations in rock properties which are fed into fully coupled reservoir/geomechanical simulations, and how these variations impact the potential injection and production from a well. The presentation will also discuss how these integrated geoscience/engineering interpretations could then be extended throughout production history matching and optimization of future drilling and completion designs.

Biographical Sketch

Dr. A. (Tony) Settari is a Professor and holds the PanCanadian/Petroleum Society of CIM Endowed Chair in Petroleum Engineering at the University of Calgary. He is also president of TAURUS Reservoir Solutions Ltd., a high technology simulation consulting firm in Calgary. Dr. Settari is one of the leading developers of simulation technology for reservoir modeling, hydraulic fracturing and geomechanics. He graduated with a BSc from the Technical University of Brno, Czechoslovakia in 1965 and PhD in Mechanical Engineering from the University of Calgary in 1973. He subsequently worked for Intercomp Inc. in Houston, Calgary and London (UK), and founded SIMTECH Consulting Services in 1983. He has been involved in a wide range of both development and application simulation projects, including naturally fractured reservoirs, enhanced recovery projects, hydraulic fracturing and acidizing, in-situ thermal processes in oil sands, perforation mechanics and more recently reservoir geomechanics. He is a co-author of a classical textbook on Petroleum Reservoir Simulation (by Aziz and Settari), has written over 100 technical publications, and has taught at the University of Calgary since 1977. In the past, he served on the Editorial board of JPT and was a Technical Editor of SPE. Tony was twice invited to be an SPE Distinguished Lecturer (in the 1989/90 and 2000/2001 season), and became Distinguished Member of SPE in 2003. He is also active in CIM and has lectured widely on the subject of reservoir simulation, geomechanics and fracturing.

Professor Mohamed Soliman, Ali Rezaei, Fahd Siddiqui
Petroleum Engineering Department, University of Houston

Role of Multiple Fracturing of Vertical and Horizontal Wells in Maximizing Production and Extending Life of the Field

Summary

As the oil industry explores production from unconventional shale plays, it has become clear that maximum reservoir contact and innovative technology must be implemented to raise the recovery factor to an economical level. This goal may be reached by creating multiple fractures and refracturing. The increased number of fractures brings several issues of production and stress interferences that would affect fracture creation and propagation.

This talk will focus on the ramifications of creating multiple fractures in vertical and horizontal wells. The effects of formation permeability, the presence of natural fractures, depleted areas, and the timing of fracturing will be discussed. Both fluid flow and the geomechanics aspects of fracturing will be examined. Analytical and numerical simulators will be used to illustrate the concepts discussed. Field examples will also be explored.

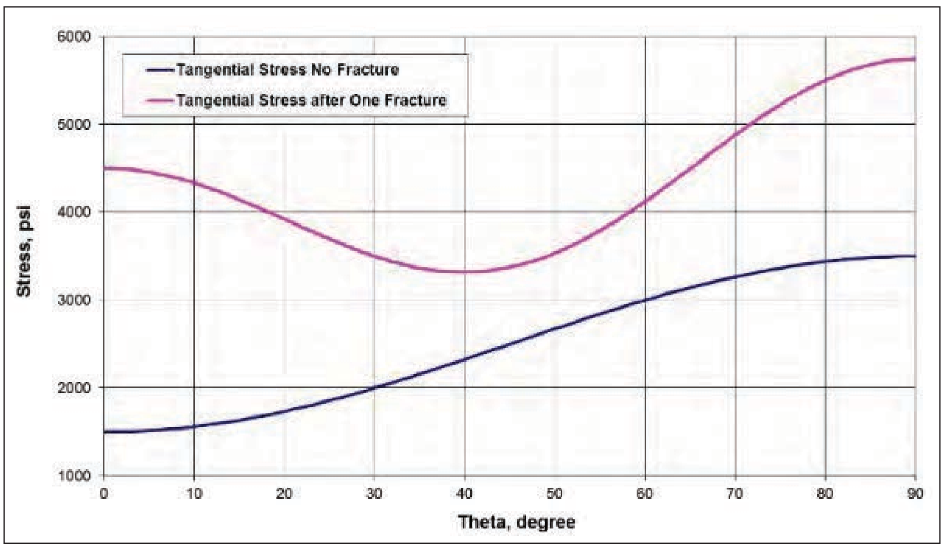


Figure 1. *Hoop stress before and after fracturing of a vertical well.*

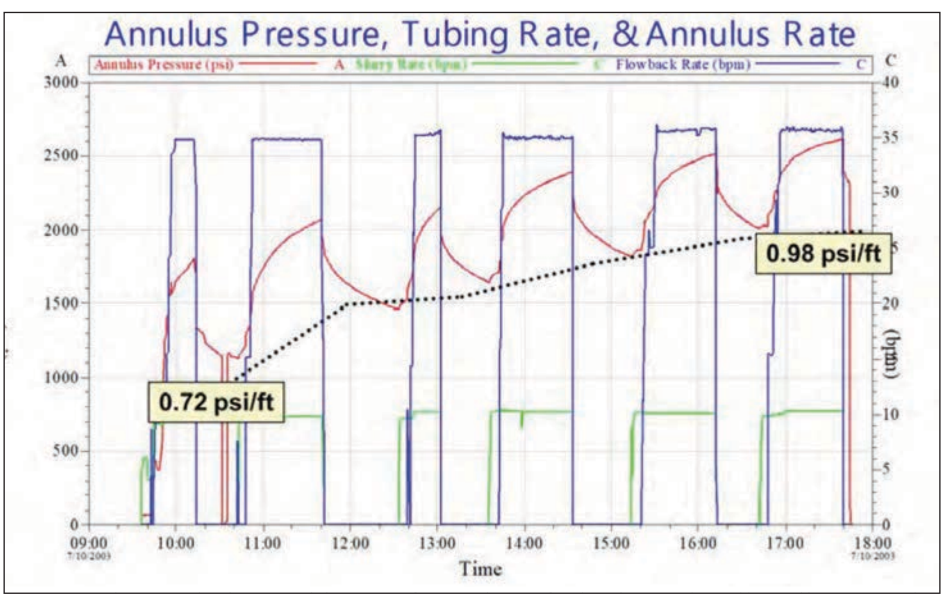


Figure 2. *ISIP change during multi-stage fracturing of a horizontal well, Soliman et al, 2008.*

Introduction

This presentation explores the role fluid flow and geomechanics play in extending the life of the field in tight reservoirs and unconventional plays. Studies have shown that as the formation permeability gets lower, economic exploitation of a reservoir requires the creation of multiple fractures and the creation of a larger Stimulated Reservoir Volumes (SRV).

In a vertical well, the creation of a fracture will affect the hoop stress around the wellbore, which in turn affects the initiation and propagation of future fractures (as shown in **Figure 1**).

The creation of multiple fractures in a horizontal well creates significant production and geomechanics effects. Stress interference (shadowing) between fractures would affect the propagation of the fractures. The stress shadowing will also cause an increase of instantaneous shut-in pressure (ISIP) of subsequent fractures as illustrated in Figure 2. Stress shadowing of multiple fractures created simultaneously from a well or wells would affect length and orientation of the fractures. This effect would be magnified as the number of fractures from a well increases and the distance between the fractures get smaller. Depletion of reservoir fluids by a fracture would lead to changes in stress magnitudes and even stress orientation. This will in turn affect the propagation of fractures from a child well both in length and orientation, Rezaei, et al 2018.

In the case of condensate or volatile oil reservoirs, the situation is more complex as the timing of fracturing is also important.

Conclusions

Refracturing may be necessary to extend the life of the reservoir. However, special geomechanical considerations have to be taken into account. This includes changes in stresses both in magnitude and orientation. The timing of fracturing is important especially in condensate or volatile oil reservoirs.

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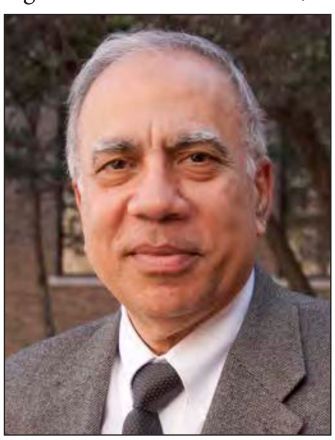
Biographical Sketch



Professor Soliman has had a distinguished career in reservoir, completion, and production engineering. His experience includes over 30 years of industrial experience and 9 years of academic experience. He holds 33 patents on fracturing operations and analysis, testing and conformance applications. He is an author or co-author of over 250 technical papers and articles in areas of fracturing, reservoir engineering, well test analysis, conformance, and numerical simulation. He has designed and analyzed hundreds of pressure transients, minifrac, frac, and micro-frac tests.

Soliman is a registered professional Engineer. He is also a distinguished member of the Society of Petroleum Engineers. In December 2014, he was nominated and elected as Fellow of the National Academy of Inventors.

He has authored chapters in World Oil's *Handbook of Horizontal Drilling and Completion Technology*, *Well Construction*, and SPE monograph *Well Test Analysis of Hydraulically Fractured Wells and Deliverability Testing and Underground Gas Storage*. Soliman is the primary editor and author/co-author of five of the chapters of "Fracturing Horizontal Wells" published by McGraw Hill in 2016. Another book on fracturing Shale formations published by Taylor & Francis Group in 2018.

He has authored several books for internal use at Halliburton, including S*timulation and Reservoir Engineering Aspects of Horizontal Wells, Well Test Analysis, Hydraulic Fracturing,* and chapters in *Conformance, Stimulation*, and *FracPac*. He is an accomplished speaker at numerous seminars, conferences, workshops, short courses, and forums both domestically and internationally. He has served as a member of numerous technical, forum and ATW committees, and has chaired numerous sessions during SPE and other engineering organizations.

He has graduated 50 PhD and MS students.

Mark Herkommer, Qube Tech LLC

Limits on the Accuracy of Pore Pressure Estimates by Analysis of Random Measurement Error and Means for Improvement

Summary

In this study, an analysis of the density tool's and the sonic tool's associated uncertainty is presented that shows how these measurement-related uncertainties propagate forward into conventional overburden and pore pressure gradient calculations. The tool based random uncertainties ultimately create a statistically reliable range for pore pressure estimations. Because different tool types have different statistical distributions of measurement error, the comparative impact of combining both relative and absolute measurement errors is also considered.

The implications of this sort of analysis suggests that there is an inherent level of uncertainty in all pore pressure calculations that can never be reduced unless there is some sort of instrumental refinement. Similarly, fracture gradient and wellbore stability calculations also must bear the weight of these uncertainties from derived quantities plus their own contributions. While breakthroughs in analytical technique are likely possible in the future, reduction of the random error by measurement cross-validation and integration is shown to be an achievable outcome without any improvements in the current technology.

Introduction

No measurement made is ever known to be exact. Accuracy (correctness) and precision (significant digits) of an instrumental measurement (i.e., logging tools and surface laboratory measurement) are subject to the underlying governing physics and the qualities of the apparatus used. As a consequence, every measurement has a range of possible true values and all quantities therefrom derived necessarily carry those uncertainties with them.

In order to produce meaningful interpretations, it is almost always necessary to combine measurements with theory to yield a derived quantity. In this particular study of error propagation, the governing theory will be the general, widely-used equations used to calculate pore pressure and fracture gradients.

LOG CURVE	MNEMONIC	UNCERTAINTY TYPE	UNCERTAINTY VALUE	SOURCE
DEPTH	TVD	RELATIVE	0.05%	Cable stretch & temperature tables
BULK DENSITY	RHOB	ABSOLUTE	0.025 G/CC	Instrumentation*
SONIC RESISTIVITY	DT R	RELATIVE	2.0%	Instrumentation*

Method and/or Theory

When making measurements, it is possible to introduce error at a number of places along the workflow[1]. Of the various error types, only repeatability and resolution error is considered in this analysis. The logging tool instrumentation measurements being analyzed are shown above.

Using these tool uncertainties, the uncorrelated and random errors are combined according to the equations employed[2].

For quantities a and b with uncertainties δa and δb, when seeking the quantity Q with uncertainty δQ, under addition and subtraction, the absolute uncertainties are added:

If $Q = a + b$ or $a - b$, then

$$\delta Q = \sqrt{(\delta a)^2 + (\delta b)^2}$$

For quantities a and b with uncertainties δa and δb (errors which are uncorrelated and random), when seeking the quantity Q with uncertainty δQ , under multiplication and division, relative uncertainties are added:

If $Q = a \times b$ or a / b, then

$$\frac{\delta Q}{|Q|} = \sqrt{\left(\frac{\delta a}{a}\right)^2 + \left(\frac{\delta b}{b}\right)^2}$$

For quantity a with uncertainty δa (errors which are uncorrelated and random), when seeking quantity Q with uncertainty δQ, under exponentiation, multiply relative uncertainty by exponent:

If $Q = a^n$, then

$$\frac{\delta Q}{|Q|} = |n|\frac{\delta a}{|a|}$$

The equations that will be used for the calculation of pore pressure and fracture gradients are shown on thenext page. Entities that carry an uncertainty with the measurement are shown bolded and underlined. All other values are treated as constants:

True Vertical Depth Below Mud Line (**<u>TVD</u>**$_{bml}$)

$\underline{\mathbf{TVD_{bml}}} = \underline{\mathbf{TVD}} - (AG + WD)$

Normal Hydrostatic Gradient (**<u>NHG</u>**) – Integrated Fluid Density (**<u>RHOF</u>**)

$\underline{\mathbf{NHG}} = (0.4335 \times \underline{\mathbf{RHOF}} \times \underline{\mathbf{TVD_{bml}}} + WD \times 0.448\ psi/ft) / \underline{\mathbf{TVD}}$

Overburden Gradient (OBG) – Integrated Bulk Density (RHOB) (rectangle rule)

$\underline{\mathbf{OBG}} = \Sigma\, ((\underline{\mathbf{TVD_i}} - \underline{\mathbf{TVD_{i-1}}}) \times (\underline{\mathbf{RHOB_i}} + \underline{\mathbf{RHOB_{i-1}}}) \times 0.4335 / 2) / \underline{\mathbf{TVD}}$

Normal Compaction Trend (**<u>NCT</u>**) – Exponential Porosity Decay function[3]

$\underline{\mathbf{NCT}} = 40 + 135 / 10^{0.000042858 \times \underline{\mathbf{TVDbml}}}$

Pore Pressure Gradient (**<u>PPG</u>**) – Eaton Equation for Sonic[4]

$\underline{\mathbf{PPG}} = \underline{\mathbf{OBG}} - (\underline{\mathbf{OBG}} - \underline{\mathbf{NHG}}) \times (\underline{\mathbf{NCT}} / \underline{\mathbf{DT}})^3$

Fracture Gradient (**<u>FG</u>**) – Matrix Stress Equation[5]

$\underline{\mathbf{FG}} = \underline{\mathbf{PPG}} + (\underline{\mathbf{OBG}} - \underline{\mathbf{PPG}}) \times \underline{\mathbf{K}}$

Example

Figure 1 is shown an analysis with the error bars. It can be seen that as measurements are combined the error bars tend to grow in length, indicating that the more uncertainty in measurements are combined, the greater the uncertainty in the final derived quantity:

Over intervals where error bars overlap, it may be possible to reduce uncertainty by combining measurements. For example, if the pore pressure gradient (PPG) is greater than the mud weight (MW), the associated error bars overlap. Also, if a kick was experienced, then it must fall in the area where the MW and PPG error bars overlap. Otherwise, the PPG must be reinterpreted and recalculated.

Similarly, if the calculated fracture gradient (FG) is less than the measured mud weight (MW), the error bars must overlap. If a loss was experienced, it must fall in the area where the mud weight and fracture gradient error bars overlap. Otherwise the fracture gradient must be reinterpreted and recalculated.

Conclusions

Systematic study and rigorous combining of error is important to understanding the effective drilling window and well behavior. By combining additional measurements that are independent of the log data, it is possible to improve interpretation quality and possibly reduce the size of the uncertainty. ■

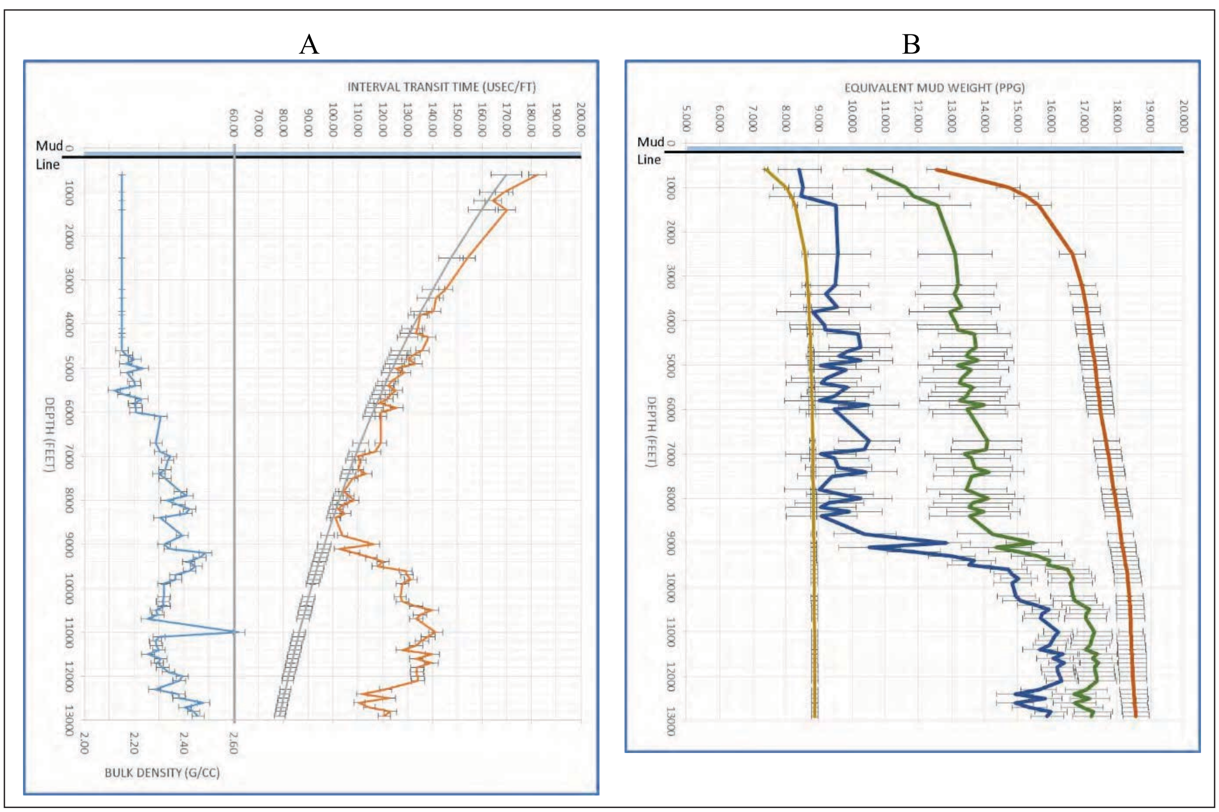


Figure 1. A – *Shows the RHOB and DT with their respective measurement uncertainties. Also shown in the NCT. The figure at right.* **B** – *Shows the resulting NHG, PPG, FG, and OBG and their inherited uncertainties. Note how the error bars overlap at greater depth.*

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Biographical Sketch

Since 1988, **Mark Herkommer**, a Licensed Professional Geoscientist in Texas, has focused his professional career on the analysis of seismic and geological data for pore pressure, fracture gradient and wellbore stability (PP/FG/WBS) interpretation. He has been involved in most geopressure and geomechanical related phases of well planning and drilling and currently manages the Data and Consultancy service line for Excellence Logging, an international mud logging company with bases in more than 30 countries around the world.

Today at Excellence Logging, Mark is actively involved the new product development, including Real-Time Geopressure-Geomechanics and Wellbore Surveillance services, which integrates Excellence Logging's Advanced Surface Data Logging measurements to provide real-time wellsite PP/FG/WBS surveillance for unconventional onshore and offshore wells.

Thursday, November 7, 2019 | Session 4 | 2:35

Z. Philip, R.G. Dusterhoft, and U. Inyang
Halliburton

Extending the Life of Enhanced Permeability Zones Created During Hydraulic Fracturing

Summary

Hydraulic fracturing operations in unconventional reservoirs consist of huge volumes of both water and proppant. While much of this material can be contained within primary or dominant fractures, a combination of formation shear failure, rock dilation, and fluid-leakoff-induced micro-fracturing will often result in a region of enhanced permeability some distance around the dominant fractures. While this region can result in improved well performance, pore pressure and stress dependence limit how long this region will contribute under normal conditions. New techniques are examined to extend the effective life of this region, significantly improving well performance.

Introduction

During some of the early hydraulic fracturing treatments in the Barnett Shale, microseismic monitoring confirmed the generation of a complex cloud of microseismic activity, suggesting a significant degree of fracture complexity (Fisher[1]). The use of low-viscosity slickwater fluids generated microseismic activity over a broader area than crosslinked fluids. Shear failures that cause the microseismic events suggest the creation of a significant altered region, enhancing effective permeability through the creation of numerous small fractures within the rock.

More recent work performed within the Eagle Ford Shale (Raterman[2]) and the Wolfcamp Shale in the Midland Basin (Gale[3] and Stegent[4]) actually cored through the microseismic region around fractured wellbores and confirmed the existence of many created fractures, many of which were not propped.

To understand this behavior better, advanced modeling with fully geomechanically coupled fracture models and reservoir simulators was performed by Sen[5], including a zone of enhanced permeability around the primary fractures to account for a region of shear failed rock created during the hydraulic fracturing process. The properties within this region appear to be pore pressure and stress dependent, with the effective permeability reducing quickly as a function of reservoir depletion.

This study focuses on the use of a microproppant (MP) material to both extend the size of this enhanced permeability zone (EPZ) around the wellbore and sustain effective permeability within this region longer under production conditions.

Method and/or Theory

Cortez[6] provides detailed measurements of effective permeability or conductivity of both unsupported fractures and MP supported fractures using multiple different shale cores under stress. Shale cores tested included Marcellus, Eagle Ford, Barnett, and Delaware Wolfcamp, providing stress dependent effective permeabilities under representative stress conditions.

This information was fed into a history matched reservoir simulator that incorporated an EPZ to achieve a better match of both production and presumed drainage around a well. The compaction tables used for the EPZ were based upon results of split core testing.

Example

Dahl[7] initially performed a study incorporating natural fractures modeled stochastically into the reservoir. In many cases, the

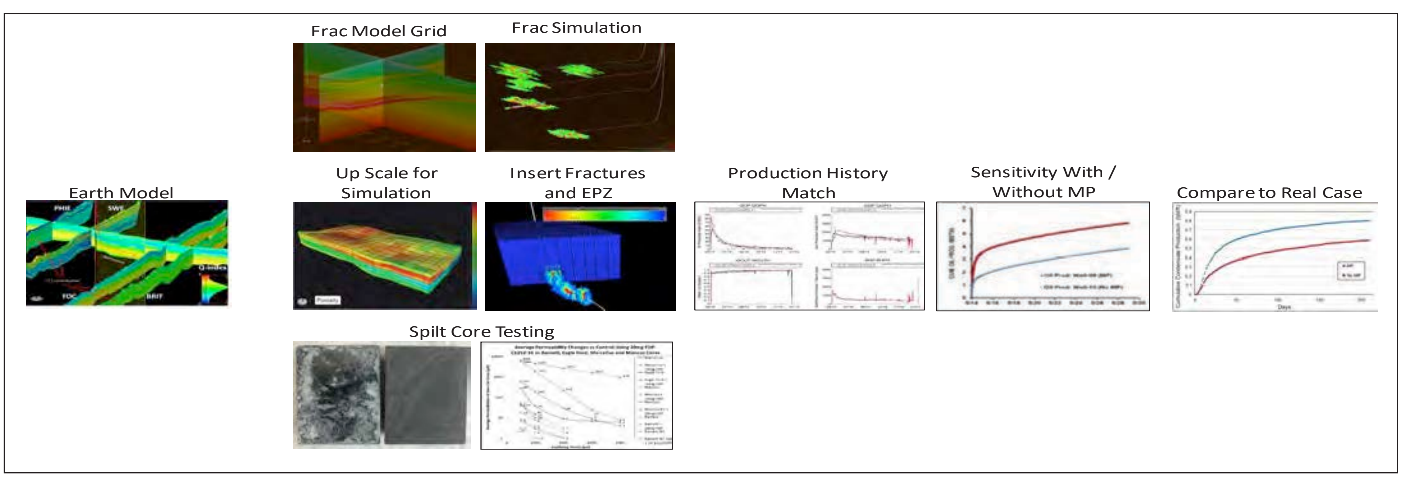

Figure 1. *Complete workflow from Earth modeling through reservoir simulation, history matching, and sensitivity testing..*

use of an EPZ is an easier means to represent this concept than performing modeling with a large number of different natural fracture realizations. The EPZ is a more reasonable means to approach the problem. **Figure 1** presents a workflow for conducting this study.

Observations

Modeling shows that fracturing treatments incorporating MP significantly extend the higher early production rates by maintaining effective permeability in the EPZ longer under production conditions.

Laboratory testing supports the behavior of extending the effective permeability within the EPZ during production conditions.

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Biographical Sketches

Ronald Dusterhoft is a Halliburton Technology Fellow for Production Enhancement with 35 years of industry experience. Ron's specific areas of thought leadership include hydraulic fracturing, FracPac completions, sand control screens, sand consolidation, sand control down hole tool systems, completion design and reservoir simulation for shale.

Ron is currently focused on drilling and completion optimization and stimulation design for unconventional, shale assets. This involves the use of full asset workflows and more effective data management to maximize collaboration and knowledge sharing between Geoscience, Drilling and Completion Engineering.

Ron has worked in multiple locations across Western Canada, Algeria, Gabon, Gulf of Mexico and unconventional assets across the United States.

Ron received his BSc in Mechanical Engineering from the University of Alberta, Canada. Ron is an active member in the SPE and served as an Editor and Peer Reviewer for the SPE Drilling and Completions Journal for the past 12 years. He served as a co-chair for two SPE Forums "Beyond Conventional Sand Control," and "Drilling and Completion Geomechanics – Integrating Knowledge and Workflows to Maximize Asset Value", as Editor for the JPT for Stimulation for 3 years and is a Professional Engineer registered with APEGA. Ron also has authored and/or coauthored more than 30 technical papers and holds more than 80 issued USA patents.

Zeno Philip is a Global Advisor with the PE Technical Services Group in Halliburton. Previously, he was Senior Diagnostic Engineer with the Center of Excellence (COE) for Hydraulic Fracturing, Pinnacle. Zeno primarily works in Integrated Sensor Diagnostic (ISD) projects that involve a multi-disciplinary approach – the use of micro-deformation, micro-seismic and fiber-optic DTS/DAS technologies in fracture modeling and the implementation of such fracture models in reservoir models for EUR and optimization studies, – and in Cypher Projects that use a more detailed earth modeling and reservoir description in EUR and Sensitivity studies for well location and completion optimization. Prior to this, Zeno worked in Pinnacle's Fracture Diagnostics Department where he primarily worked in micro-deformation analysis using tilt-meters (surface and downhole), GPS and InSAR measurements. Micro-deformation analysis includes the mapping of hydraulic fracture parameters created during fracture treatments as well as the prevention of unintended surface breaches during steam flooding and cyclical steam injection. It is also used in obtaining reservoir strain magnitudes using poro-elastic models from surface micro-deformation measurements. Zeno holds an MS and PhD degree in Petroleum Engineering from the University of Texas at Austin and is a licensed professional engineer in the State of Texas. He is co-author of several papers in SPE and other journals.

Saad T. Saleh, GEOMECH

Predrill Pore Pressure Estimation – The Art and Science in Wildcat Prospectivity

Seismic based predrill pore pressure prediction is a fundamental task for planning and construction of exploration wells. In remote wildcat settings, offset wells may not be available. Velocity based pressure prediction therefore is the primary pore pressure prediction approach, which may or may not be supported by additional approaches (such as basin modeling). Therefore, the uncertainty in the velocity-based pore pressure prediction is significant. The prediction uncertainty is caused by uncalibrated seismically derived velocity (main input variable) and pore pressure model parameters selection. This uncertainty greatly challenges the exploratory well planning and execution process. Unfortunately, these challenges are increasingly prevalent as ultra-deepwater prospects are being planned and drilled.

This talk addresses the impact of seismic velocity uncertainty on pore pressure prediction and the application of different available methods to reduce this uncertainty. A pore pressure prediction workflow is presented based on integration of geomechanical, basin hydrodynamics, and the geological drivers responsible for pore pressure generation or relevant in pore pressure prediction. Case studies are presented to support the concepts outlined in this paper, which have proven successful in reducing prediction uncertainties.

Biographical Sketch

Dr. Saleh earned his PhD degree from the Colorado School of Mines (Petroleum Engineering) in 1988. Since then, Dr. Saleh worked globally as an academic, researcher, instructor, mentor, and industry consultant. With over 30 years of industry and academic credentials, Dr. Saleh literally have written the book on geopressure prediction in all types of geologic settings and for most of the world active exploration basins.

Poster Presentations

November 6-7, 2019

Southwestern Energy
Spring, Texas

Juan Camilo Acosta
The University of Oklahoma

Study of Creep Behavior in Barnett Shale Using Nanoindentation

Several studies have demonstrated the application of nanoindentation to study mechanical properties, mainly Young's modulus and hardness (Babko and Ulm 2008, Kumar et al. 2012) of shales. The main advantage of nanoindentation is that it requires small pieces which makes it ideal for friable shale samples where it is very difficult to obtain large samples. However, only few studies have been published reporting creep measurements on shales using this technique (Wick 2015).

Nanoindentation was performed on 14 vertical Barnett shale samples. Total organic carbon (TOC) ranged from 2 to 9 wt. %, quartz ranged from 14 to 48 wt. %, carbonates ranged from 5 to 47 wt. % and clays ranged from 25 to 63 wt. %. Three sets of experiments were performed: first, on dried samples (at 100 °C for two days), then on 2.5 wt% KCl brine imbibition (saturation ranged from 20 to 70%) followed by measurements on re-dried samples. The indentations were set to reach a load of 490 mN. In order to have a significant representation of creep properties, the holding time was set at 600 seconds.

Results show good repeatability after re-drying the samples, suggesting little or no damage to the samples during saturation and re-drying states. The stress exponent and creep displacement were obtained using the steady state creep law. Results show creep displacement is inversely proportional to the hardness, and increase as a function of the amount of soft components (clays and TOC). The stress exponent obtained could be used to calculate the creep strain on a rock. Average stress exponent decreases from 7.1 for dry conditions, to 2.9 on brine imbibition, indicating a significant increase in plastic deformation with fluid existence.

This work suggests that mineralogy of the formation should be stongly considered when doing proppant placement. Soft layers will have more creep and this will affect long term production. The stress exponent difference also suggests that creep measurements should be done under fluid imbibition to have a closer simulation to reservoir conditions. ■

Biographical Sketch

Juan Camilo Acosta was born and raised in Bogotá, Colombia and moved to the United States when he was 17 years old. Juan Camilo is very passionate about sports and follows every sport where his country has action. He did his BS in Petroleum Engineering at the University of Wyoming, where got to know people from everywhere in the world and found it as "the coldest place he has ever been". His parents are his primarily motivation and he believes that he would not be where he is at without their help and support. One of his dreams is to go to a World Cup, he is very enthusiastic about football and loves to watch every game of his national team.

Currently Juan Camilo is a Master's student on Petroleum Engineering at The University of Oklahoma, where he works on studying petrophysical and mechanical properties of the rocks, especially on shales. He enjoys working in a laboratory and he spends most of his time there. He is very motivated to graduate and eventually work in the industry, using all the knowledge and experience gained during his time in the university.

Shivam Agrawal and Mukul M. Sharma
Hildebrand Department of Petroleum and Geosystems Engineering, The University of Texas at Austin

Predrill Pore Pressure Estimation – The Art and Science in Wildcat Prospectivity

Induced un-propped (IU) fractures are formed around the main hydraulic fracture due to its interactions with heterogeneities at different length scales. In post-fracturing simulations, the increase in permeability due to these IU fractures is modeled by incorporating a Stimulated Reservoir Volume (SRV) around the hydraulic fracture. The spatial extent and permeability of the SRV is usually estimated by history-matching the flowback or production data. In this research, we explore the mechanisms for the creation of the SRV at pore scale and the effect of this SRV on fracture propagation at field scale.

A coupled peridynamics and finite-volume based hydraulic fracturing simulator was developed and applied to study failure mechanisms and fracture propagation at different length scales. Peridynamics captures the effect of heterogeneities particularly well, but it is computationally expensive. Thus, coupling with the less expensive finite volume method allows us to capture the important details within reasonable computational times.

The simulation study is carried out in two parts for computational tractability. In the first part, fluid is injected into a hydraulic fracture and the poroelastic stress changes are computed several meters away from the fracture face. A pore scale region with mineral heterogeneity (including clay, quartz, and calcite) is considered at different distances from the fracture. Several orders of mesh refinement are used in transitioning between length scales, which allows us to capture the stresses accurately throughout the computational domain. The pore scale region is discretized and solved using peridynamics, while the rest of the domain is solved using a finite-volume method. In peridynamics, the failure regions are characterized by damage fields, whose permeability is obtained by interpolating using a sigmoid function. In the second part, considering the damage-dependent permeability as a proxy for the SRV permeability, fracture propagation is simulated at field scale. This allows us to study the effect of SRV (formed due to smaller scale heterogeneities) on field scale fractures.

The poroelastic stress changes due to fluid injection into the hydraulic fracture lead to the failure of grain boundaries between soft (clay) and hard (quartz) minerals at the pore scale. Moreover, brittle mineral grains such as those comprised of calcite can break. The magnitude of the strain (determined by the fracture width) controls the spatial extent of the SRV. In addition, the rock fabric and mineralogy play a critical role in the extent of failure induced at the grain boundaries and within the grains. More failure is observed closer to the hydraulic fracture. Failure regions like these form the SRV and their hydraulic conductivity and distance from the fracture face provide an estimate of the permeability and the spatial extent of the SRV. A formation with a higher matrix permeability or a lower Young modulus transmits stress changes farther and forms a bigger SRV. Moreover, the role of poroelastic stress changes on failure at the pore scale is demonstrated by simulating fracturing fluids with different viscosities.

In this paper, a novel method is presented to explore the mechanisms by which the SRV is created and to estimate the spatial extent and permeability of the SRV. Subsequently, the effect of SRV on field scale fracture propagation is demonstrated. A coupled peridynamics-finite volume fracturing simulator is used to accomplish this. These independent estimates can reduce the uncertainty due to non-uniqueness of the SRV parameters obtained from history-matching.

Biographical Sketch

Shivam Agrawal is a PhD degree candidate in the Hildebrand Department of Petroleum and Geosystems Engineering at The University of Texas at Austin. His research interests include geomechanics, hydraulic fracturing, reservoir engineering, and machine learning. Agrawal holds bachelor's and master's degrees in chemical engineering from the Indian Institute of Technology Kharagpur, India.

Abdullah Bilal
University of Houston

Predicting Static Data Using Dynamic Data and Quantitative Sample Characterization

This work develops an improved understanding of the stress-strain dependence of data along a "triaxial" stress path. "Static data" are defined as the large strain ($> 10^{-3}$) measurements on unloading and reloading along multistage tri-axial stress paths. "Dynamic data" are the small strain ($<10^{-6}$) data acquired using standard pitch and catch acoustic velocity measurement techniques. The multistage triaxial stress path is a systematic exploration of the yield surface of a single sample by performing triaxial tests at increasing confining stress. The samples were measured "dry" i.e. equilibrated to ambient conditions. The effects of acoustic dispersion and poroelastic effects are therefore assumed negligible. The results of the strain dependent experiments are analyzed in terms of Young's Modulus and Poisson's ratio. A quadratic fit has been applied to static data. This allows us to separate the response into linear and nonlinear elastic terms, with coefficients M_1, and M_2 respectively. The rest of the strain is assumed to be plastic strain. M_1 is dominated by the contact modulus and is constant throughout the entire unload and reload cycles. M_2 the nonlinear elastic term, is due to the opening and closing of compliant pores. These interpretations are based on the equality we find between M_1 and the measured modulus determined from the velocity and the correlation we find between M_2 with the measured irrecoverable strains. Acoustic velocity is predicted from the static data using the measured M_1 data. A compaction model (Myer's, Hathon, 2014) is modified to fit plastic strains. This work provides robust connection between the Young's modulus derived from static and dynamic data to that derived from empirically based correlations. Based on this work the strain dependence of Young's modulus can be predicted. A model has been used to predict the static data including the irrecoverable strains. This work will ultimately involve the use of thin section and/or microCT data to provide a mineralogical and textural based methodology to predict the model parameters.

Biographical Sketch

Abdullah Bilal is a PhD candidate at University of Houston in Petroleum Engineering department. His undergrad degree is in mechanical engineering and master's degree is in Petroleum engineering. His research interests include: Geomechanics, acoustic properties, strength properties and rock physics etc.

Suresh Dande, Robert R. Stewart, Michael T. Myers, Lori Hathon, Nikolay Dyaur
University of Houston

Elastic Properties of Propped and Unpropped Eagle Ford Shale and 3D-printed Fractured Rock Models

In a hydraulically fractured reservoir, estimating propped reservoir volume is key to predict production. In this study, we use various samples, including 3D-printed models with air-filled plus sand and ceramic proppant-filled fractures, as well as Eagle Ford Shale samples with artificially created fractures with air and sand-proppant. From the 3D-printed model in uniaxial compression experiments, we found that V_p and V_s decreased by 4-5% for the sand-proppant model, and the Young's modulus of propped models are lower than the air-filled or unpropped models, suggesting that propped models may be more compliant. We extend this experiment with Eagle Ford Shale samples, we find that shear velocity increased by 8-14% in propped rock in all directions (00, 450, 900 to the bedding). The increase in shear velocity could be attributed to the addition of faster material(sand) to the saw cuts. For only two propped fractures at ultrasonic wavelengths, we observed significant increase in shear velocity. With dense propped fractures in the field, at microseismic wavelengths, we might see change in shear velocity in propped rock volume. In both 3D-printed and Eagle Ford shale experiments, S-waves attenuate more than P-waves in propped rocks. ■

Biographical Sketch

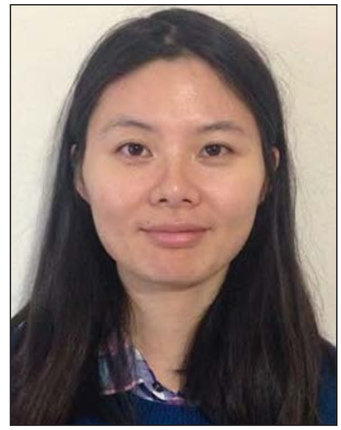
Suresh Dande is a geophysicist with 5+ years of experience monitoring and processing borehole microseismic data for 60+ hydraulic fracturing jobs in a variety of US and international unconventional reservoirs. He is also current Geophysics PhD candidate at University of Houston. His research focuses on integrating geomechanics and geophysics to better understand hydraulically fractured reservoir rock. From 2009-2011, Suresh worked as Research Assistant in Aeromagnetics at National Geophysical Research Institute, Hyderabad, India. Suresh Dande holds a MS in Geophysics from Andhra University (India), a MS in Geology from Southern Illinois University at Carbondale, IL. Overall, Suresh Dande has 7+ years of professional experience.

Rongrong Lin
University of Houston

A Damped Dynamic Finite Difference Approach for Modeling Static Stress-strain Fields

Modeling dynamic and static responses of an elastic medium often employs different numerical schemes. By introducing damping into the system, we show how the widely used time-marching staggered finite difference (FD) approach in solving elastodynamic wave equation can be used to model time-independent elastostatic problems. The damped FD method can compute elastostatic stress and strain fields of a model subject to the influence of an external field via prescribed boundary conditions. We also show how to obtain an optimized value for the damping factor. We verified the damped FD approach by comparing results against the analytical solutions for a borehole model and a laminated model. We also validated our approach numerically for an inclusion model by comparing the results computed by a finite element method. The damped FD showed excellent agreement with both the analytical results and the finite element results. ■

Biographical Sketch



Rongrong Lin is a Geophysics PhD candidate from University of Houston. Her research topic is about modeling stress-strain fields using finite difference approach. She received a BS (Geophysics) from Ocean University of China in 2011, a MS (Geophysics) degree from University of Houston in 2013. She has a patent 'System and Method for Estimating Seismic Anisotropy with High Resolution' which is based on her Master thesis. Rongrong has worked for Halliburton from 2013-2017 as a geophysical software developer serving the borehole seismic research and development team.

Ming Liu and Haiying Huang
School of Civil and Environmental Engineering, Georgia Institute of Technology

Poroelastic Indentation – Feasibility of a New Testing Method for Tight Rocks

The process of indentation by a rigid tool has been widely studied for its versatility as an experimental technique to probe constitutive properties of materials of various kinds across multiple scales. Recently the technique has been applied to characterize poroelasticity of soft materials such as polymeric gels via load relaxation experiments, where an indenter is pressed instantaneously to a fixed depth and held until the indentation force approaches a horizontal asymptote. Assuming incompressibility in both the solid and fluid phases, elastic constants are determined from the early and late time response, while the hydraulic diffusivity is obtained from the transient response by matching the experimentally obtained indentation force as a function of time against a master curve obtained from FEM simulations [1].

Motivated by these experimental advances in soft materials, we theoretically analyze indentation of a poroelastic solid by a spherical-tip tool for a surface in fully drained, fully undrained or mixed drainage condition. Compressibility of both the fluid and solid phases is considered in these solutions. Though derivation of these fully coupled solutions requires the aid of a variety of mathematical techniques, the result in terms of the normalized indentation force relaxation with time is remarkably simple. The transient force response shows only weak dependence on one derived material constant and can be fitted by elementary functions, which lend themselves to convenient use for determining hydraulic diffusivity, thus permeability indirectly, of tight rocks in the laboratory.

Poroelastic indentation test could offer a few unique advantages. Firstly, compared with the conventional steady-state flow test, duration of the test can be greatly shortened with the proper choices of the indenter size and the depth of penetration. Secondly, in principle, the method can be adopted to probe material properties at multiple scales.

Theoretical solutions and prior experiments from the literature will first be shown. Feasibility of potentially developing spherical indentation into a new laboratory testing method for determining material properties for tight rocks will then be discussed.

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Biographical Sketch

Ming Liu earned his BS degree in 2012 and MS degree in 2015 both majored in Petroleum Engineering from China University of Petroleum, Beijing. He is currently a PhD student in the Geosystem Group at Georgia Institute of Technology and expected to graduate in December 2020. He has been working on the theoretical development of poroelastic indentation as a new testing method for tight rocks.

Jingyao Meng
Oklahoma State University, Kansas Geological Survey, University of Kansas
Jack C. Pashin, Runar Nygaard
Oklahoma State University
Avinash Chandra
Oklahoma State University, BP America Inc.

Geomechanical Characteristics of the Prospective CO_2 Sinks and Seals, Eastern Gulf of Mexico

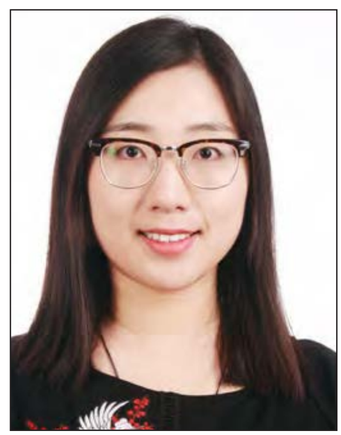
Subsurface geologic storage of CO_2 can play a major role in offsetting greenhouse gas emissions, and offshore storage in the DeSoto Canyon Salt Basin in the east-central Gulf of Mexico may be a viable solution due to large storage capacity (~150) Gt in Cretaceous-Cenozoic sandstone. The Cretaceous reservoirs are overlain by thick sections of tight mudrock, limestone, and chalk, which form regionally extensive seals. Understanding the structural styles and geomechanical properties of the associated reservoir rocks and seals is therefore essential for safe and effective CO_2 storage.

The structural framework in the Mississippi-Alabama-Florida shelf of the Gulf of Mexico includes the DeSoto Canyon Salt Basin, the Middle Ground Arch, and the Tampa Embayment. The Central DeSoto Canyon Salt Basin is structurally complex due to the presence of peripheral faults, salt pillows, salt rollers, and salt diapirs. Multiple faults associated with the peripheral faults and salt pillows displace the potential Cretaceous reservoirs and seal intervals. Elongation of borehole breakouts is aligned with the minimum horizontal compressive stress (Sh_{min}), which tends to be oriented northeast-southwest. Vertical reservoir stresses are influenced by rock and fluid density. Lithostatic and hydrostatic stress each have a power-law relationship to depth. The average lithostatic stress (Sv) gradient is ~21.4 kPa/m. Hydrostatic pressure gradient increases with brine density to a maximum of ~12.2 kPa/m. Geometric mean of the Sh_{min}-depth values corresponds to an effective Sh_{min}–effective Sv quotient of ~0.5. Reactivation tendency and seal analysis of the major faults shows that while the slip tendency is small, the dilation tendency and potential for cross-formational flow is relatively high, particularly where reservoir strata in the footwalls are juxtaposed with sealing strata in the hanging walls. Geomechanical analysis of reservoir and seal strata indicates that prospective reservoirs and associated seals are stable if injection pressure does not exceed fracture pressure.

Favorable CO_2 injection sites are available throughout the stable shelf areas of the DeSoto Canyon Salt Basin, where faults with high dilation tendency are absent above the Jurassic section. Future research should focus on further geomechanical, pressure, and flow simulation of the potential reservoirs and associated seals.

Predicting reservoir potential of unconventional shale plays from wireline logs: a correlation between compositional and geomechanical properties of the Devonian Duvernay Formation, Alberta, Canada. ■

Biographical Sketch



Jingyao "Jenny" Meng received the PhD degree in geology from Oklahoma State University in 2019. Her research focuses on the structural and geomechanical assessment of reservoirs in the context of the structural framework, fault seal integrity, and reservoir geomechanics. She is currently a postdoc researcher at Kansas Geological Survey, the University of Kansas, working on seal analysis and rock mechanic test of the potential reservoirs for carbon sequestration and enhanced oil recovery.

Sabyasachi Prakash
University of Houston

Experimental Study of Unconsolidated Sand Yielding Behavior Under Unloading Conditions

Mechanical behavior of rocks under loading conditions depend on stress path and stress magnitude. With increasing load (both mean and shear stress), rocks have an elasto-plastic behavior until they fail and can carry no additional load. Within the loading yield surface, constitutive models assume rocks behave elastically and are independent of the stress path and magnitude (e.g., Mohr Coulomb theory).

We tested this theory experimentally with test samples made with unconsolidated sands (no cementation) and under unloading conditions. We mapped the loading yield surface with a multi-stage triaxial test with yield criterion of point of positive dilatancy. We then studied the yield behavior under two unloading stress paths of Constant Axial stress test (CAT) (reducing mean stress and increasing shear stress) and Constant Shear stress Test (CST) (reducing mean stress and keeping shear stress constant). Results showed the unloading-based yield surface is also stress path and stress magnitude dependent. However, the unloading and loading based yield surfaces are not the same. For the CAT stress path, the unloading yield criterion is the same as the loading yield criterion. While for the CST, the yield criterion is different than the loading yield criteria and this stress path is being investigated further.

Practical application of this research includes prediction of geomechanical behavior of unconsolidated sands under injection conditions. It is not uncommon to use the same rock's constitutive model derived from loading stress paths for injection geomechanical simulations. They provide results for injector design, injection performance, and safe injection envelope. Therefore, it is essential to have constitutive model representative of unloading stress paths. We have demonstrated that the yield criterion (point of positive dilatancy) is reached before we hit the loading-based yield surface during injection (decrease in effective mean stress), hence there is an unloading based yield surface which has lower cohesion than the loading based yield surface. This suggests that the loading-based yield surface may not be true for yielding under unloading conditions for unconsolidated sands.

The use of loading based yield surface for injector geomechanical simulations in unconsolidated sand reservoirs warrants further evaluation. We are planning additional tests to study the combined effects of stress magnitude and unloading stress path on the yield surface of unconsolidated sand and its effect on permeability of the unconsolidated sands. The results of this research are intended to update the simulation software and account for stress path and stress magnitude effects while performing simulation for injectors.

Biographical Sketch

Sabyasachi Prakash is a PhD candidate in petroleum engineering at the University of Houston. His expected graduation date is August 2020. He graduated with his MSc in petroleum engineering from University of Houston and his BS in Mining Engineering from India. His PhD dissertation is in the field of injection geo-mechanics in deep-water unconsolidated sandstone reservoirs. His research interests include permeability dependence on stress path and stress magnitude, failure and yield surface characterization, rock physics, borehole stability and skin effects, and digital rocks.

Mehdi Teymouri and Zoya Heidari
The University of Texas at Austin

Coupled Hydro-Mechanical Analyses and Modeling for Reliable Characterization of Fracture Propagation in Anisotropic and Spatially Heterogeneous Formations

The interaction of solid and fluid phases is a critical factor to be taken into account in characterization of geomaterials. For instance, in the case of hydraulic fractures, the injected high pressurized fluid plays a crucial role in the variation of effective stress resulting in the mechanical failure, the fracture propagation, and enhancing the rock fracture conductivity. Furthermore, it is not reliable to evaluate either the hydraulic or the mechanical properties of rock without considering the pertinent coupled processes.

The objective of this research includes developing a workflow to simulate the coupled hydro-mechanical processes in spatially heterogeneous porous media with the purpose of quantifying the impacts of petrophysical properties on the evolution of hydraulic and natural fractures. Therefore, we satisfied the fundamental conservation principles. Then, by considering the featuring sound and proven constitutive relations, we captured the coupling among relevant phenomena associated with hydro-mechanical problems. Moreover, we implemented the ordinary state-based peridynamic theory because it paves the path to cope with undefined spatial derivatives at discontinuous boundaries appearing upon the initiation and propagation of hydraulic fractures.

We successfully tested the reliability of the developed framework using the results of an analytical solution for the case of consolidation, which is a common coupled hydro-mechanical problem. Then, we performed the sensitivity analyses to observe the effects of petrophysical properties (e.g., a wide range of contrasts in elastic properties within laminated formations with various thicknesses, dip angles, permeability coefficients, and burial depths) on geomechanical responses (e.g., the variation of effective stress and the evolution of strain in solid phase). These sensitivity analyses explain the characteristic behaviors of fracture propagation, including crossing, kinking, branching, and turning near the interface of laminations with contrast in mechanical properties. Furthermore, conditions under which each type of aforementioned behaviors is expected to occur are categorized. The results are promising for the application of the developed numerical simulator in complex anisotropic formations to evaluate the spatial displacement of natural and hydraulic fractures.

Biographical Sketch

Mehdi Teymouri is a Postdoctoral Scholar in the Hildebrand Department of Petroleum and Geosystems Engineering at the University of Texas at Austin. He holds a PhD degree (2018) in Civil Engineering from Texas A&M University. His expertise lies in the area of geomechanics, considering engineering problems involving thermal, hydraulic, geochemical, and mechanical couplings. His research interests also cover the study of rock mechanics, unsaturated soils, energy geotechnics (e.g., hydrate bearing sediments, hydraulic fracturing, sand production, geothermal energy), and geoenvironmental engineering.

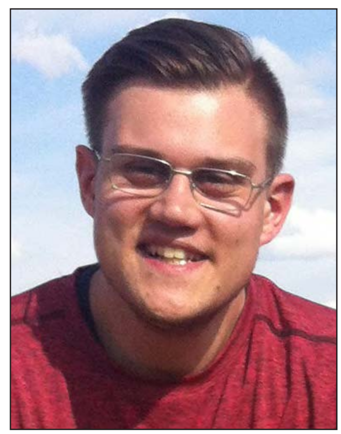
Marco Venieri, Per K. Pedersen, David W. Eaton
Department of Geoscience, University of Calgary

Predicting Reservoir Potential of Unconventional Shale Plays from Wireline Logs: a Correlation Between Compositional and Geomechanical Properties of the Devonian Duvernay Formation, Alberta, Canada

Unconventional reservoir performance is commonly assessed by integrating mineralogical and static geomechanical analyses performed on drill core or cuttings. This approach has significant limitations; for example, it can only be deployed where drill core and cuttings are available, and even in this case detailed sample analysis may not be cost-effective at the full scale of a resource play. In this research we propose an original workflow that integrates mineralogical and geomechanical properties of unconventional shale plays measured in core to well log-estimated compositional, mineralogical and geomechanical properties of the shales. The correlation obtained facilitates the extrapolation of compositional and mechanical properties of unconventional reservoirs into areas characterized by scarce core coverage, but available wireline logs. Using the Western Canadian Duvernay shale play as a natural laboratory, our analysis reveals a high degree of correlation between core-measured XRD mineralogy and 2 main well log suites: Elemental Capture Spectroscopy (ECS) and Spectral Gamma Ray (SGR). More specifically, we show how ECS and SGR log readings, together with other more common log suites, can be used to identify silica-rich, clay-rich and carbonate-rich intervals within the reservoir. These 3 compositional end-members represent 3 petrofacies with unique reservoir properties and their co-existence is common in most of the major North American shale plays. We show how these 3 well log-based petrofacies also display unique dynamic geomechanical properties, suggesting that they also hold unique hydraulic fracturing efficiency and thus reservoir potential. Finally, our workflow gives insights on how to use the ratios between the thickness of each of the 3 petrofacies vs the total thickness of the reservoir to quantify compositional heterogeneity and build contour maps highlighting areas where the petrofacies of exploration interest is dominant.

Since wireline logs are generally much more abundant than drill cores - especially in the early play exploration phase - our approach may prove critical in assessing reservoir potential ahead of the drill bit not only in the Duvernay, but in similar unconventional opportunities worldwide.

Biographical Sketch



Marco Venieri is a PhD Geology Candidate at the University of Calgary (Canada) researching the influence of sedimentary facies, fabric and composition on geomechanical properties of the Duvernay unconventional shale play (Alberta, Canada). He holds a BSc degree in Geology summa cum laude from the University of Bologna (Italy) and a MSc degree in Petroleum Geology summa cum laude from the University of Bologna (Italy). During his career he has been involved in several hydrocarbon exploration and development projects in the Mediterranean Sea, NW Australia, Western Africa and Western Canada. He is author and co-author of over 15 scientific papers, conference abstracts and technical reports in the last 4 years focusing on unconventional reservoir characterization.

Wenjing Wang
Purdue University

Heterogeneous Stress State in the Crystalline Crust Beneath the Western Canada Sedimentary Basin: Observations from Borehole Image Logs to 2.4 km

NE-SW compression is generally indicated by borehole failure features to the east of the deformation front in the Western Canada Sedimentary Basin. These data, however, exclusively originate from borehole measurements within the sedimentary column. As such, the Hunt well drilled to nearly 2.4 km into the Proterozoic crystalline basement in NE Alberta provides an unprecedented opportunity to investigate the stress state beneath the sedimentary cover. Stress orientations were observed by three different types of data: breakouts/ induced tensile fractures from ultrasonic borehole imager (UBITM), fast shear azimuth from dipole shear sonic imager (DSITM) and long/short caliper direction from four-arm caliper log. These indicate, SHmax direction of 21.50°±24.79° above 2000 m rotating dramatically to 88.59°±18.78° over a short interval from 2000-2155 m, and below 2155m, to 58.23°±32.82°. There are no significant fractures or fault zones within the image logs that might disrupt the stress field. Further, the shifts do not obviously correlate with any distinct changes in density, composition, or mechanical properties as inferred from an extensive set of geophysical logs. It is also unlikely that the elastic anisotropy of the rock mass, as measured from core, is responsible. While we cannot absolutely rule out instrumental error, possible reasons for these rotations, other possible reasons may be related to the location of the borehole relative to flexure during lithospheric loading of the lithosphere to the west, currently ongoing glacial unloading, or residual stresses.

Biographical Sketch

Wenjing Wang is a PhD student at Purdue University after she graduated with a BS degree in marine sciences from Zhejiang University, China. Having spent four years of her undergraduate research on combining both seismology and rock mechanics, she is no stranger to either fields. Since experienced in both fields, she has nurtured a keen interest and is determined to solve problems encountered in natural resource explorations by using both experimental and field methods. Realizing the central role of data sciences, Wenjing also built skills in data engineering and is proficient in python and SQL/NO SQL database.

Other than academia, she also knows the beauty of communication and education. She is super passionate about introducing her research to general public and is thus active in outreach activities.

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

The Role of Pre-existing Fractures in Permeability Creation during Shale Reservoir Stimulation

The development of unconventional petroleum resources from low permeability shale reservoirs frequently requires hydraulic stimulation to achieve economic flow rates. Most reservoir rocks contain abundant pre-existing fractures, some of which may be sealed with calcite or other infill minerals. Usually, these fractures are inactive and without enough permeability before stimulation. A number of modeling and field studies have shown that the pre-existing fractures can play an important role in permeability creation during hydraulic stimulation. However, the reactivation of pre-existing fractures and its contribution to permeability enhancement are still poorly understood, and the experimental results on permeability evolution in fractured shales are limited. In this work, we present results of novel laboratory-scale injection tests on shale rocks. One set of cylindrical samples each containing a single-open fracture were used to conduct injection-induced shear slip tests to probe the shear-induced fracture dilation and permeability increase during hydraulic injection. The other set of cylindrical samples with pre-cut embedded fractures were used to explore the fracture network generation and permeability enhancement in response to the propagation and coalescence of pre-existing fractures by injection. These laboratory observations clearly show that fractures slip, dilation, propagation, and coalescence are key and often concomitant mechanisms of permeability enhancement contributed by pre-existing fractures, and would help engineer solutions for maintaining permeability, reducing costs (proppant, water and additive cost savings) during hydraulic stimulation in shale reservoirs. ■

Biographical Sketch

Zhi Ye is a PhD Candidate in Petroleum and Geological Engineering at The University of Oklahoma, working with Prof. Ahmad Ghassemi. He conducts research in the areas of reservoir geomechanics, geophysics, and rock mechanics. His recent research focuses on experimental and numerical investigation on the role of pre-existing fractures/faults in permeability creation and induced seismicity during reservoir stimulation. He has over 8 years' experience in experimental rock mechanics and rock physics. He is the winner of the 2019 Rock Mechanics Research Award from the American Rock Mechanics Association (ARMA). He has authored/coauthored over 20 peer reviewed journal and conference papers.

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