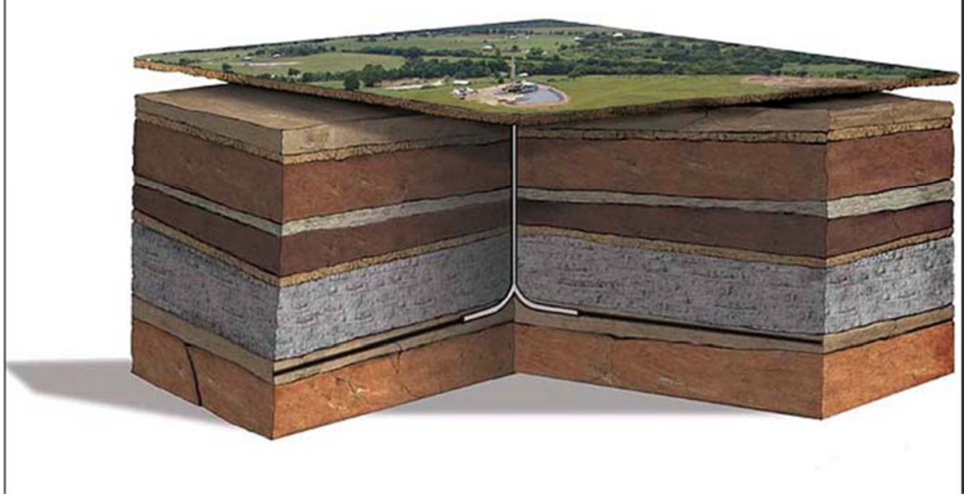

Timely Technical Presentations

Crack the Unconventional Code

Vetted Case Histories

High - Level Keynote Talk

Network with Peers

MARCH 20TH, 2018 (8:30AM - 4:30PM)

SPE-GCS WESTSIDE STUDY GROUP PRESENTS TECHNICAL SEMINAR

CASE HISTORIES IN UNCONVENTIONAL RESERVOIR COMPLETIONS

VENUE: CORE LAB (6323 Windfern), HOUSTON

SPE - GCS WESTSIDE STUDY GROUP

Online registration opens February 1st, 2018

http://www.spegcs.org/study-groups/westside/

World oil prices have started to creep up from their 2015-16 lows and this has led to a frenzy to accelerate completion in Unconventional Reservoirs (UR). Fracture stimulation is the mantra for the day with operators pumping millions of pounds of proppant per well. With most shale/UR plays in the USA in developmental mode, operators and service companies are using innovative designs to extract the most from the ground.

This one-day technical seminar is designed to be one where operators and service companies present case studies/best practices on key topics in an effort to understand the unconventional puzzle.

Topics to be discussed include, but are not limited to:

- Cluster spacing/stage length
- Job sizing/fracture stimulation design
- Re-Fracture treatments
- Zipper operations/surface constraints
- Pad development strategies
- New technologies

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WSG 2018 Seminar - Program Agenda

Time	Speaker	Presenter	WSG- Chair
07:30-08:15		Light Breakfast/Registration Badge Pick Up	
08:15-08:30	David Demshur	Opening Remarks/Safety Orientation	
Session 1		***08:00-10:00***	***Buddy/Derek***
08:30 -09:00	Craig Cipolla	HESS	
09:00-09:30	Ray Ellis	Liberty Oilfield Services	
09:30-10:00	Joel Fox	Encana	
10:00-10:30		***Coffee Break***	
Session 2		***10:30-12:00***	***Steve B/Brian***
10:30-11:00	Matt Woltz	PDC Energy	
11:00-11:30	Mohammad Hamad	Shell	
11:30-12:00	Kumar Ramurthy	Halliburton	
12:00-13:00		***Lunch***	
Luncheon Key Note Speaker			
12:15-12:45	***R.T. Dukes***	***Wood Mackenzie-The World of Oil is Watching the US***	
Session 3		***13:00-14:30***	***Lucy/Purvi***
13:00-13:30	Brendan Elliott	Devon Energy	
13:30-14:00	Ahmed Attia	Ziebel	
14:00-14:30	Alberto Casero	BP	
14:30-15:00		***Coffee Break***	
Session 4		***15:00-16:30***	***Alex/Buddy***
15:00-15:30	David Craig	Oxy	
15:30-16:00	Duy Nguyen	NALCOChampion	
16:00-16:30	Karthik Srinivasan	Schlumberger	
16:30-17:00		***Closing Session/Wrap Up***	

1. Case History of Completion Optimization in the Utica – Craig Cipolla- HESS

Objectives/Scope

The paper details the results from a comprehensive study to evaluate completion effectiveness and optimize field development in the Utica. Optimizing the number and location of perforation clusters, number of stages, and treatment size requires a clear understanding of how these parameters effect fracture geometry and well productivity. The goal of this work was to determine how the number of perforation clusters per stage and treatment size effect fracture geometry and well productivity and to integrate these results into the overall field development optimization.

Methods, Procedures, Process

A comprehensive evaluation of plug-and-perf (PNP) and controlled entry point (CEP) completions and treatment size was performed using a 5-well pad in the Utica (wet gas area). The evaluation included PNP completions with 3-4 perforation clusters and CEP completions with 1-2 perforation clusters. Treatment size was varied by a factor of two to evaluate the effect of fluid volume on fracture length. Microseismic data were gathered on 81 PNP stages and 95 CEP stages. The microseismic data were used to calibrate hydraulic fracture models. Fracture geometries for the 5-well pad plus a direct offset well (Six well total of 250+ stages) were discretely gridded in a reservoir simulation model. The reservoir simulation model was calibrated by history matching 12+ months of production data. Proppant Tracer data and DFIT measurements from previous Utica work were used to support the hydraulic fracture modeling and reservoir simulations.

Results, Observations, Conclusions

The microseismic data provided a clear understanding of the relationship between treatment size and fracture length for each completion scenario. The results indicate that fracture length may be dependent on completion type, with CEP completions showing less fracture length than PNP completions. Simple production comparisons and detailed reservoir simulation history matching showed that (1) well productivity is governed by the number of perforation clusters, with PNP wells outperforming CEP wells and (2) well-to-well communication is evident. This work DID NOT identify any gross inefficiencies with PNP completions and suggests that CEP completions DO NOT result in better productivity – at least in this Utica pad. Thus, the calibrated models were used to optimize perf cluster spacing, treatment size, and well spacing for PNP completions. The optimization results will be briefly summarized in the paper, but the focus of the paper is the evaluation of PNP and CEP completions, characterization of hydraulic fracture length-volume relationships, and calibration of hydraulic fracture and reservoir simulation models.

Novel, Additive Information

Both planar and complex hydraulic fracture models were calibrated to the microseismic data. The results show that fracture geometry assumptions can significantly impact optimization decisions.

2. What Can We Learn by Combining Multi-Variate Analytics with Physics-Based Models in the Permian Basin – Ray Ellis- Liberty Oilfield Services

Multi-variate models (MVA) have been primarily used as a scoping tool for better completion designs. The ability to “right size” completions has always been a primary objective for any stimulation development program. The objective of this innovative approach is to look beyond the statistics by combining physics- based models to add depth to our understanding of Permian Basin completion strategies.

While there are hundreds of variables to consider, statistically only a few are relevant to their impact on production. The addition of physics-based models creates a hybrid model to provide a more realistic prediction of how completion parameters affect production. The physics-based addition incorporates reservoir parameters for a given area to achieve the predictive aspect. Another factor that can be better understood is the role economics plays when optimizing completion designs.

The result is a model that incorporates MVA and economic optimization to minimize the Cost/BO to predict an optimized completion design in the Permian Basin.

3. **Stimulation 5ivertŜǁ !ppliĐations in Ʀefracs and ƅeǁ ² ell /ompletions–JoeƖ C2ÈπEnclͼna**

In order to try to improve stimulation perforation cluster efficiency in horizontal multi-stage completions, Encana has been experimenting with 2 mechanical diverters currently available to operators. These tests are being conducted in two plays in which the company is active – the Eagle Ford play south of San Antonio and the Permian Basin outside of Midland, TX. In the Eagle Ford one diverter is being used in refracs, while in the Permian play, a different diverter is being used in new well completions. Examples of these trials will be shown in this seminar.

4. **Completion Operations in a a ature DJ Basin—Matt Woltz - PDC Energy**

PDC Energy has been drilling horizontal wells in the DJ basin since 2011. Although a mature field, completion designs vary largely from operator to operator and have evolved over time. This presentation will look at PDC's completion operations and how they have helped turn the play into a premier asset for the company. Stage spacing and clusters will first be examined. Are more stages always better? What is the ideal number of clusters per stage? We'll explore some of the testing we've done with both stage spacing, clusters, and different proppant intensities. Next, we'll look at surfactants and the benefits we've received from them. Finally, we'll conclude with optimizing completion techniques by area and bench. By looking at competitor operating practices and verifying through trial and error, we've proved up that one size definitely does not fit all in the DJ basin.

5. **Justifyin∃ /2YLJtŜűĭ2ƴ 5Ŝăĭ∃ƴ /KͼƴƎŜă ĭƴ űKŜ tŜǁYĭͼƴ ² 2ťŦŏͼYLJ ¦ăĭƴ∃ !ƴͼťèűĭŎă — a 2KͼYYͼŘ Hamad-Shell**

Its highly desirable to use empirical data to estimate scaling factors that relate design to productivity to see how "big" we can go economically. Linear regression is a simple way to estimate scaling factors, however, it is not great at dealing with complex or nonlinear relationships, such as subsurface influences. In this presentation, we use other methods to deal with the subsurface factors, while preserving the strengths of the regressions for scaling factor estimation in the Permian Wolfcamp.

6. **Benchmarking and Pad/DSU Focused Completions vs. Single Well Completions (FracInsight 3D™ with NexGenStim™)—Kumar Ramurthy - Halliburton**

This talk will emphasize pad/DSU focused completions as opposed to single-well completions. The benchmarking will help understand the original hydrocarbon in place, and the objective then is to extract the maximum possible recovery from the reservoir. A case history from an unconventional play will be presented. The case history will show the integration of sub-surface information with frac and reservoir modeling towards an end goal that is optimized pad recovery.

7. **Development of a Ten-well, Multi-Interval Project in the Delaware Basin: Insights into Well Spacing, Stimulation Design, Fracture Driven Communication and Offset Depletion—Brendan Elliott - Devon**

The project consisted of drilling ten wells in three different landings, five of which were development wells and five of which were appraisal wells landed in various intervals. Different well spacing and fracturing treatments were pumped while monitoring pressure responses of offset wellbores monitoring the reservoir. Known geologic variability was considered and reviewed, as well as tied to the diagnostic data captured. Offset pressure monitoring, fluid tracers, interference tests, and various other technologies were implemented. Advanced internal data capture processes allowed the team to quickly and effectively leverage near real-time pressure responses to draw insights into the rolling development of the complex interval.

This study illustrates a real executed development of a multi-well stacked development, on which the industry has published few detailed case studies. New technology and methods were utilized, with support of standard diagnostics, that led to the advancement of knowledge of stacked developments Insights can be gained on well spacing, sequencing, and geologic variability of unconventional reservoirs.

8. **Optimizing Completion Strategies Using Intervention Based Distributed Fiber Optics—Ahmed Attia- Ziebel**

This presentation will demonstrate the continuing evolution of DFO technology and the different methods for understanding stimulation and completion efficiency by dip-in distributed fiber optics (DFO). Confirmation of optimized completions is a key goal for operators where DFO has been at the forefront for unconventional wells. The core of this technology targets an in-depth understanding of unconventional flow profiles where the focus lies in cluster efficiency and stage spacing.

The focus will be on a case study from a U.S. unconventional well, where a 0.6" OD, 22,000-foot-long carbon fiber rod was deployed to acquire DAS and DTS for post-frac flow evaluation. The case study will explain how DFO measurements are taken during a post-frac sensing operation, where the combination of distributed acoustic and distributed temperature measurements are used to provide a clear and thorough completion analysis.

The data acquired were used to provide a detailed understanding in regard to single-stage completion versus multistage completion. Understanding the effectiveness of a multistage frac with the utilization of diverter was at the heart of the client's main objective. It is understood that multi-stage completions can reduce well costs significantly; however, clients are left with wondering if multistage completions are leaving them with a cost of reduced production at surface. Considering the qualitative analysis with cluster efficiency and stage strength, which is illustrated by noise power, gave the client ammunition to effectively make several key decisions in their future completions.

When it comes to evaluating stimulation and completion design techniques, using intervention-based DFO technology will give a thorough diagnostic to ensure maximum recovery at minimum completion cost.

9. The Importance of Being Well Connected - High Rate Fracs in Horizontals—Alberto Casero - BP

In the majority of fractured oil and gas wells, conventional perforating is the typical approach of choice to provide the primary connectivity of fractures to the wellbore, and in horizontal wells the very discrete nature of this connection assumes a significantly higher importance. In multi-fractured horizontal wells, this connection drives the ability to efficiently place the fracture treatments during pumping and the efficiency with which the fracture can subsequently be produced. Consequently, selection of the most appropriate connection technique can be absolutely key to many aspects of the successful implementation of a fracturing campaign.

The use of shaped-charge perforating is quite commonplace and predominantly considered as the best practice for the majority of scenarios in order to establish fracture/wellbore connectivity. However, there are certain situations where such approaches may not provide an efficient solution. This is particularly true in those horizontal wells drilled and completed in complex stress regimes, as well as in reasonable permeability reservoirs that have multiphase flow potential or with just a few transverse fractures that are expected to produce at moderate to high production rates from each frac. In these particular cases, a complex connection resulting from perforating can often be detrimental to fracture width creation, making proppant placement challenging and reducing effective fracture conductivity. Additionally, convergent and multi-phase flow behaviour can create extremely high pressure drops in the near-wellbore area, subsequently impeding the productivity.

While open-hole completions can be one of the methods to deal with this situation, by effectively eliminating the "problem" at the source, this is typically delivered at the expense of the loss of control on the point of fracture and also with a statistical isolation failure rate. When this is implemented in multi-stage/multi-cluster frac environments (effectively hundreds of fracs), such statistical failure is an acceptable risk. However, when a single-well frac count is just 3, 4 or 5 per well, any statistical failure can be materially impactful on the well productivity. In those cases when open-hole is not an attractive approach, then cased-cemented is preferred, and the application of abrasive jetting can provide an effective alternative to the use of shaped-charges.

This paper will fully describe a suite of tests performed with different shaped-charges, as well as abrasive jetting perforators, static holes and dynamic slotting for the multi-fractured horizontal wells in the Khazzan tight-gas condensate field in the Sultanate of Oman. The paper will also include a comprehensive review of multiple injection tests that were performed in both Khazzan vertical and horizontal wells (Al Shueili *et al.*, 2016), through both shaped-charge and abrasive jetted connections. This review will offer observations on maximizing the effectiveness of the pre-frac wellbore connection technique in challenging environments.

10. Determining Fracture Geometry in a Multifractured Horizontal Well Using DFIT Interpretation, Intra-well Fracture-to-Fracture Interference, and Production History Matching ---- David Craig, OXY

Determining the number of producing fractures, half-lengths, and conductivities has proven difficult in multifractured horizontal wells. The methodology to be presented uses a prefrac well test to constrain effective permeability and initial reservoir pressure. The prefrac well test will most often be a diagnostic fracture-injection/falloff test (DFIT) in a nearby well or at the toe of the lateral, and a key to the approach is the identification of intrawell fracture-to-fracture interference from a reciprocal productivity index derivative diagnostic plot. After identifying the intrawell interference, the production rate and the reciprocal productivity index derivative are history matched using reservoir simulation and by varying the number, half-length, and conductivity of fractures along the lateral. Field examples demonstrate that with effective permeability and initial reservoir pressure constrained by a DFIT interpretation(s), and by matching the characteristic signature of the intrawell fracture-to-fracture interference in addition to the production history, realistic estimates for the number of producing fractures, fracture half-length, and fracture conductivity can be obtained from production data analysis.

11. <u>Surfactant Induced Wettability and Adhesion Alterations in Bakken Shale: An EOR Case Study—</u>

<u>Duy Nguyen—NALCO Champion</u>

Advanced technologies in horizontal drilling and multi-stage hydraulic fracturing have led to an increase in oil production in tight oil reservoirs. However, the decline curves and oil recovery factors are still very low due to low permeability, low porosity and oil-wet nature of tight oil formations. Most published works have reported lab studies and simulation models for EOR in tight reservoirs but case studies are limited. In this study, we introduce the concept of work of adhesion, calculated from contact angle and interfacial tension measurements, which can be used to predict the interaction between the rock surface and the competing crude oil, brine, and surfactant. This has led to the development of a patented surfactant to enhance production in tight oil reservoirs. After a comprehensive laboratory testing, a field trial was conducted in the Bakken formation. A thorough analysis of the lab and field data (pre- and post-treatment) was provided in this study. Further investigation was also performed through oil rate decline analysis and numerical simulations to obtain more insight about the true effectiveness of the chemical treatment. The results of this field trial showed that this patented surfactant improved oil recovery by up to 25% of the estimated ultimate recovery (EUR) in a huff-n-puff application (25% incremental EUR). The results of numerical simulations also revealed that the additional oil recovered in this field trial cannot be achieved by either shut-in or straight water injection.

The lessons learned from this study provide practical information to optimize similar field trial designs leading to more profitable projects. Incremental EUR is expected to be larger if the same chemistry is utilized in completion or re-frack jobs in which the contacted area with the oil-bearing matrix was much greater. The concepts and information here can be also translated to additional unconventional basins and gas condensate or dry gas reservoirs.

12. Bakken Enhanced Oil Recovery Consortium – Phase 1 and Phase 2 Results—Karthik Srinivasan-Schlumberger

The Energy and Environmental Research Center (EERC) at the University of North Dakota, in collaboration with several operator and service companies has been working on a consortium to evaluate the feasibility of Enhanced Oil Recovery in the Bakken Formation. The project, planned in 3 phases, has already crossed major milestones and is currently in the process of testing horizontal injection pilots with several injection fluids, including CO2 and produced gas. Phase 1 of the consortium includes lab testing of core samples utilizing digital rocks and Focus-Ion-Beam Scanning Electron Microscopes to understand rock properties and wettability characteristics. Core or plug scale reservoir simulations were performed to determine the impact of CO2 injection on overall hydrocarbon recovery. As part of Phase 2, an unstimulated vertical well was picked for CO2 injection — several cycles of injection were performed, flow-back data were evaluated, and composition of hydrocarbon samples collected were used to fine-tune PVT and relative-permeability data. As we enter Phase 3 of the project, current progress includes utilization of a Big Oil Factory with state-of-the-art surface facilities and infrastructure for continuous injection experiments in horizontal wells.