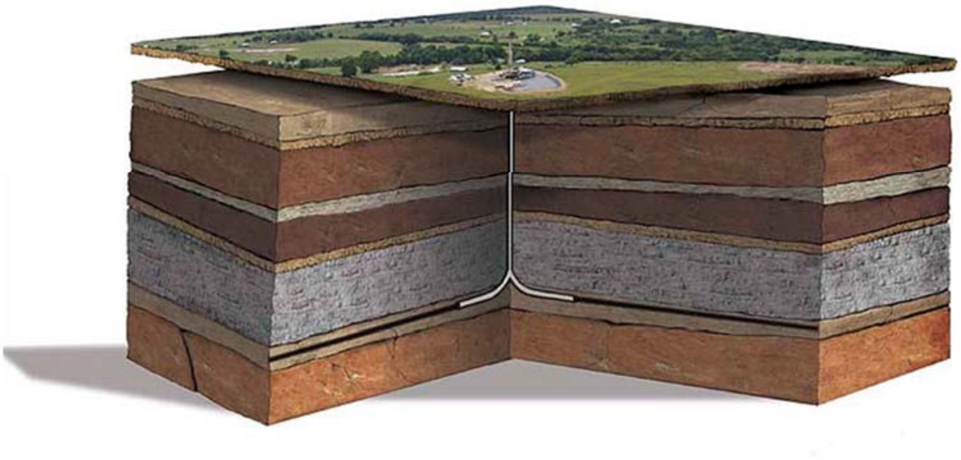
Gulf Coast Section



MARCH **6**TH, 201**9** (8:30AM - 4:00PM)

SPE-GCS WESTSIDE STUDY GROUP PRESENTS TECHNICAL SEMINAR

OPERATOR PERPSPECTIVES: **UNCONVENTIONAL RESERVOIR COMPLETIONS**

VENUE: CORE LAB (6323 Windfern), HOUSTON

Timely Technical Presentations

Crack the Unconventional Code

Vetted Case Histories

High - Level Keynote Talk

Network with Peers

SPE - GCS WESTSIDE STUDY GROUP

Online registration opens January 15th, 2019

https://www.spegcs.org/events/4080/

World oil prices have started to sway like a ship on the high seas. This has led to varying decisions made by operating companies in L48 USA as companies decide where best to invest for the optimal rate of return. 2019 may turn out to be a roller coaster for unconventional reservoirs as spacing and stacking dominate the Permian, Eagle Ford and Bakken established plays. Does this leave the SCOOP/STACK, Niobrara and other L48 unconventional plays far behind or in a race against time ?

Come find out what's in store on March 6th, 2019.

This one-day exclusive technical seminar is designed to be one where operating 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 Efficiency
- Infill Strategies
- Re-Fracture/Parent-Child Fracture Design
- Well Spacing/Stacking
- Data Analytics

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		WSG 2019 Seminar- Program Agenda	
Time	***Speaker***	***Presenter***	***WSG- Chair***
07:30-08:15		Light Breakfast/Registration Badge Pick Up	
08:15-08:30		Opening Remarks/Safety Orientation	***Bharath***
Completions: Session 1		***08:30-10:00***	***Buddy/Derek***
08:30 -09:00	Joel Fox	Encana	
09:00-09:30	Bren Broadhead	Devon Energy	
09:30-10:00	Evan Rodgers	PDC	
10:00-10:15		***Coffee Break***	
Completions: Session 2		***10:15-11:45***	***Steve B/Lucy***
10:15-10:45	Somnath Mondal	Shell	
10:45-11:15	Vikram Sen	Anadarko	
11:15-11:45	Anthony Ngyuen	ConocoPhillips	
11:45-13:00		***Lunch***	
Luncheon Key Note Speaker			
12:15-12:45	***Erec Isaacson***	***VP- Gulf Coast Business Unit, ConocoPhillips***	
Reservoir: Session 3		***13:00-14:30***	***Bharath/Joshua***
13:00-13:30	Craig Cipolla	HESS	
13:30-14:00	Yongshe Liu	ConocoPhillips	
14:00-14:30	Nick Franciose	QEP	
14:30-14:45		***Coffee Break***	
Reservoir: Session 4		***14:45-15:45***	***Alex/Buddy***
14:45-15:15	Lionel Ribeiro	Equinor	
15:15-15:45	David Craig	OXY	
15:45-16:00		***Closing Session/Wrap Up***	

1. **RA tracer tests to measure perf cluster efficiency in the Permian- Joel Fox, Encana**

The Encana Permian team started high intensity completions mid-way through 2017. We initially went from a 5-cluster stage design to 10 clusters per stage. The team is now executing 15-20 clusters per stage. While well results improved with this change, the team wanted to know what perf cluster efficiency was being achieved with the new well design. After seeing results from RA tracer projects in other basins, the team approved a test in the Permian Basin.

This presentation will summarize the results from radioactive tracer tests conducted in two wells drilled in the Sprayberry formation.

2. **Optical Fiber Case Study- Estimating cluster efficiency using perforation friction calculations- Bren Broadhead, Devon Energy**

   A case study leveraging a permanent optical fiber installation with Distributed Acoustic Sensing, Distributed Temperature Sensing, and bottom hole pressure data to corroborate the use of Monte Carlo simulations to estimate the number of perforations being treated while pumping. By implementing the perforation friction equation and treatment data, an estimated perforation efficiency can be calculated. This diagnostic method is most effective with limited entry perforation schemes. This STACK case study was performed to evaluate the use of an inexpensive diagnostic tool to determine when perforations were lost, and the resulting potential overcapitalization of pumping the same amount of proppant into fewer perforations than designed.

3. **The Balancing Act Between Cluster/Stage Spacing, Sand/Fluid Efficiency, and Fracture Fluid Properties: Examining Results of Completions Tests and Challenging Previous Completions Practices to Make Better Production and Economics- Evan Rodgers, PDCE**

   Throughout US onshore completions teams are applying numerous designs changes in an effort to make better production and economics. In more recent time, the industry has seen heavy emphasis on "improved" designs in regard to limited entry (perf design), fracture fluid rheology, and sand/fluid placement. These include, but are not limited to tighter cluster spacing, larger volumes of both sand and fluid, and varying degrees of fluid properties and pump rates.

   Over the past couple of years, PDC's completion teams have put an emphasis on evaluating these design parameters and their overall impacts to the asset development and value. Here we will examine PDC completions tests and their production diagnostics in the Wattenberg Field (DJ Basin) as well as public findings to help quantify what is potentially driving production and ultimately economics in Wattenberg as well as thoughts regarding sand and fluid placement theory. In short, PDC is observing opposing production performance compared to recent industry findings. All of which have varying inflow relationships, line pressure curtailments, and other pertinent drawdown variances that must also be accounted for when designing a stimulation treatment.

4 Uncertainties in Step-down Test Interpretation for Evaluating Completions Effectiveness and Near Wellbore Complexities- Somnath Mondal, Shell E&P

In recent years, step-down tests (SDTs) have made a comeback for diagnosing completions effectiveness in plug and perf fracturing in shales. It has been used primarily to quantify pressure drop related to perforation friction, near-wellbore (NWB) tortuosity, and to estimate perforation efficiency i.e. the fraction of active perforations at the end of a hydraulic fracturing treatment stage. In the industry, perforation efficiency is generally considered to be the measure of success for evolving limited entry designs and perforation strategies.

However, simple as it may appear to be, the interpretation of SDT as a stand-alone diagnostic technique has several assumptions and inherent non-uniqueness that are often neglected in prevalent analysis methodology. In this talk, the authors have highlighted some of these uncertainties that need integration with additional diagnostics to resolve. Data and interpretation are shared from two wells both of which were equipped with Fiber Optics (DAS and DTS) and bottom-hole pressure gauges but had very different completion designs. In the first well, SDTs were conducted on several stages of a single-point entry completion with cemented-sleeves that have well-defined, erosion-resistant openings. The analysis shows that the exponent of flowrate commonly used to quantify pressure drop associated with NWB tortuosity is largely uncertain. In the second example, SDTs were conducted on multiple stages of a plug and perf well. Each stage had two SDTs – one was conducted post pad but before proppant and another at the end of entire treatment, both with clean fluids.

The analyses show that a range of perforation diameters and number of active perforations can match the SDT and Fiber Optic data. This demonstrates that without constraints on either eroded perforation diameter or number of active perforations, the interpretation of SDT is particularly non-unique. DAS/DTS analysis also illustrates the highly variable and non-unique tortuosity and/or complex stimulation domain architecture in the near wellbore region. It is therefore recommended that SDTs be interpreted with consideration of the inherent complexities and uncertainties, and preferably supplemented either with perforation imaging or DAS/DTS data for more accurate analysis.

5 **Completions Optimization Using Hybrid Workflows – Unleashing Data Analytics on Dynamic SRV Simulations- Vikram Sen & Kyoung Min, Anadarko Petroleum**

Physical modeling has limitations of assumptions and formulations, and while it is useful in giving shape to notions of physics which we believe in, they cannot alone be used to analyze legacy completions and predict outcomes of future changes. We will present a hybrid approach that combines dynamic SRV modeling (using smart proxies) with data analytics to spot and extract those trends and interdependencies which reside beyond the most obvious. Stimulations in unconventional reservoirs result in complex changes which are spatially and temporally variable throughout the lives of wells.

We will show that the relative relevance of control parameters defining completion jobs change over time and need to be assessed over separate time windows. The variable behavior of the SRV is deeply impacted by geomechanical reservoir characterization and we will also discuss alternatives to commonly used fine scaled non-unique realizations. Our data examples cover a number of prominent US onshore plays.

6 **Fail Safe: Leveraging Technology to Reduce Cost of Failure- Anthony Nguyen, ConocoPhillips**

Low oil prices can stagnate innovation and make operators wary of expensive remedial operations that reduce their bottom line. This presentation details how operators are using technology to reduce the cost of failures, and how it helps them grow their business in a down market. Braided line is not new technology, but its use in pumpdown applications to retrieve lost fish is massively cost effective when compared to coiled tubing. Similarly, addressable perforating systems turn misfires in to misruns, and allow faulty internal wiring to be caught before reaching bottom.

When the cost of remediating failure is reduced, operators can take bigger risks. Over the last year, COP Eagle Ford has leveraged technology to reduce our cost of failure by over 70%, or to eliminate it entirely. Development of unconventional reservoirs is dependent on learning quickly from failure and on moving forward. Our reduction in the price of failure has allowed us to move quickly along the path to success.

7 **Multi-Disciplinary Data Gathering to Characterize Hydraulic Fracture Performance and Evaluate Well-Spacing in the Bakken- Craig Cipolla, HESS**

The presentation summarized a project to improve Bakken well-spacing using trial pads with smaller spacing and multi-disciplinary data gathering to understand the most effective spacing between wells. The operator's standard well spacing between Middle Bakken (MB) wells in the East Nesson area [Alger Field] ranges from 500-700 feet. To understand the optimum spacing between wells in this area, the operator trialed well spacing of 500 feet between like-formations. Hence, the spacing between Middle Bakken and Three Forks wells was 250 feet. Data gathered during the spacing trial included microseismic, microseismic depletion delineation (MDD), radioactive (RA) tracers, chemical tracers, image logs, pressure measurements during completion/flowback/early-time production, and DFITs. The data was used to calibrate advanced hydraulic fracture models and guide next generation reservoir simulation history matching to characterize multi-well production behavior.

The MDD in the parent well provided data to "map" drainage patterns, showing that drainage was limited to the MB formation. However, microseismic showed that hydraulic fracture height extended from the Three Forks second bench (TF2) up through Three Forks first bench (TF1), Middle Bakken, and into the overlying Lodgepole – connecting the entire Bakken petroleum system. The microseismic also showed asymmetric fracture growth toward the parent well in the DSU, but the asymmetry diminished as completions progressed away from the parent well. In addition to the MB-TF connectivity indicated from the microseismic, RA tracers pumped from a Three Forks second bench well were detected in a Middle Bakken well. The implied transport of proppant from a lower TF completion (TF2) to the MB increases the likelihood of production communication between formations. Chemical tracers (oil and water) pumped during hydraulic fracturing operations were found from one end of the pad to another (over 2,500 feet) regardless of formation; another confirmation of hydraulic communication between Middle Bakken and Three Forks wells.

The hydraulic fracture model was calibrated using microseismic data and used for subsequent reservoir simulation history matching. The workflow consisted of modeling the parent well hydraulic fractures and history matching production, performing geomechanical modeling to determine the effects of parent well depletion on 3D stress state for hydraulic fracture modeling of the infill wells, and production history matching of the entire pad. The modeling showed significant fracture-to-fracture communication and well-to-well interference. The operator quickly utilized these learnings to optimize well spacing across the area to maximize DSU value

8 Bakken Infill Pilot Study- Yongshe Liu, ConocoPhillips

In this presentation, we plan to discuss results/observation from an infill pilot study from the Williston Bakken formation.

A down spaced DSU having parent wells targeting the Middle Bakken (MB) and Upper Three Forks (UTF) formations and fractures stimulated with sliding sleeve completion forms the basis for this study. After several years production, infill wells are drilled in MB and Middle Three Forks (MTF) formations and completed with modern style plug & perf completion. Completion scheme was carefully designed to improve infill well fracture growth by leveraging stress shadow effect. Many fracture hits were observed in surrounding parent wells during fracking, impacting parent well production performance.

Various types of data were collected. An integrated model is built to understand infill scheme sensitivity and forecast long-term well production. This model workflow includes geological model, hydraulic fracture model, production history matching and geomechanics coupling. The acquired data and interpretation are used for model calibration. The impacts of parent well drainage on infill fracture growth will be discussed based on the data-driven modeling results.

9 <u>Tank Development in the Midland Basin: A case study of super-charging a reservoir to optimize production and increase well densities- Nick Franciose, QEP</u>

To optimize both surface and subsurface operations as well as reservoir performance in tightly-spaced and stacked stratigraphic horizons in the Midland Basin, QEP Resources Inc. has developed a novel multidisciplinary methodology called "tank development." The principle element of tank development is exploiting a volume of rock at one time in order to maximize reservoir potential. The principle result of the field tests in the Andrews-Martin counties is that productivity indexes for the wells in the tank development program clearly exceed the productivity indexes of non-tank wells using a standard sequential approach. In addition, tank development effectively eliminates the detrimental effects of parent/child sequential well interactions, including negative impacts from child wells completions on parent well production, and poor stimulation results in child wells caused by parent well energy sinks.

10 <u>Re-Stimulation Strategy for Infill Well Development: A Bakken Field Case Study-Lionel Ribeiro, Equinor</u>

As operators continue development at tighter well spacing, interference between new and existing wells can result in sub-par production performance. This talk discusses a pad-level re-stimulation strategy consisting in re-fracturing the old producers (i.e. *parent* wells) prior to stimulating the newly completed offset wells (i.e. *child* wells) in order to: (1) mitigate the production loss commonly observed on child wells during in-fill development, and (2) revitalize the production of the parent wells.

The talk will share the results of a comprehensive field-testing campaign where several diagnostics were deployed to assess wellbore coverage of the re-fracturing diversion treatment and fracture asymmetry from the child to the parent child wells. The talk will share lessons learned to further improve multi-drop diversion re-fracturing designs.

11 <u>Effects of En Echelon Hydraulic Fracture Swarms on DFIT Analysis and Reservoir Engineering-David Craig, OXY</u>

All field experiments imaging or coring through created hydraulic fractures have shown fracturing treatments result in multiple en echelon fracture swarms. Recent evidence of hydraulic fracture swarms has included the ConocoPhillips field experiment in the Eagle Ford and GTI's Hydraulic Fracturing Test Site I field experiment in the Wolfcamp formations of the Midland Basin, but historical evidence of en echelon fracture swarms extends back to the GRI's MWX and M-Site projects in the 1990s.

With consistent evidence of en echelon hydraulic fracture swarms, reservoir engineering should account for effects of en echelon hydraulic fracture swarms in well test analysis, including DFIT, and rate-transient analysis. Using numerical and semi-analytical solutions, the effect of en echelon hydraulic fracture swarms is examined versus the classical assumption of a single planar vertical fracture. While additional research remains to be completed, preliminary results demonstrate that fracture swarms with fracture spacing less than 10% of the fracture half-length have the same reservoir flow character as that of a single planar fracture. Wider spacing, however, does create flow enhancement. As part of the study, a framework is suggested for including en echelon hydraulic fracture swarms in DFIT, well testing, and rate-transient analysis. Additionally, field examples are included to demonstrate the effect of en echelon hydraulic fracture swarms on DFIT interpretations.