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About Us

The Crisman Institute for Petroleum Research is a unique program for academia. Founded years ago with a private endowment to support research in the department, the Crisman Institute has grown to a current permanent endowment of more than $5 million, the income of which is supplemented by annual contributions from 21 sponsoring companies to yield an annual funding level of about $2 million. Industry representatives help identify problems of major significance and support projects of particular interest to them through membership in the institute. Researchers in the Crisman Institute work closely with industry to identify and solve significant hydrocarbon recovery research problems through the four research centers in the institute: the Halliburton Center for Unconventional Resources, the Chevron Center for Well Construction and Production, the Schlumberger Center for Reservoir Description and Dynamics, and the Center for Energy, Environment and Transportation Innovation.

The focus of each center is to develop technology and processes to reduce uncertainties and costs in the finding and development of petroleum resources. This is done through the construction of databases of known resources to provide analogs to new resource opportunities and by developing technologies that either diminish the costs involved in existing technology applications or that amplify the reserves per completion as a result of better technology. We address both costs and the ultimate recovery per completion where applicable in our research efforts in the institute.

The institute also strives to produce significant advances in upstream petroleum engineering technology through the combined efforts of faculty, post-doctoral researchers, and highly qualified graduate students, in close cooperation with industry. Our faculty have decades of experience in technology development for petroleum resources and combine their talents within the four research centers to continue this development as required by industry. Current major research focus is on unconventional hydrocarbons including tight and source rock (shale) resources, plus support of programs on improved recovery from conventional resources.

The institute has several member companies headquartered in other countries (Australia, Canada, Norway, and the United Kingdom), in addition to major international and smaller independent U.S.-based companies.

Since 2005, the Crisman Institute has funded a total of 245 projects of which 216 are complete. During 2014 there were 29 active projects with an average of 32 Crisman-supported graduate students per semester.

Much of the research conducted through the institute has resulted in the development of software and databases that are used by industry. An additional benefit member companies have experienced is the opportunity to become familiar with our students and their research, which has often led companies to hire them post-graduation.

Members

Beginning 2009, membership in the Crisman Institute is $90,000 per year. Members are entitled to participate in all activities of the Institute and to obtain reports on any Crisman project. Members are invited to all research meetings for all projects.


Costs

- Membership in the Crisman Institute for Petroleum Research is based on a calendar year.
- The annual dues for membership are currently $90,000.
Meetings

The Crisman Institute Meetings for 2014 consisted of two meetings, each lasting two days.

**Spring Meeting:**
April 30, 2014
Topics covered included assessment of brackish and saline aquifers and flowback waters for hydraulic fracturing fluids, investigation of fracture fluid performance in oil shale with surfactant additives by x-ray tomography methods, physicochemical interactions of shale with injected water-based fluids, re-use of produced waters and hydraulic fracturing fluids, applications of CO$_2$ for unconventional reservoirs, and characterization and simulation of discrete fracture networks.

May 1, 2014
Topics covered included enhanced in situ assessment of petrophysical properties and kerogen spatial distribution in organic-rich source rocks using well logs, developing enhanced well logging methods for fracture characterization in organic-rich source rocks using nanotechnology, acid fracture performance, experimental investigation of flow reversal to characterize liquid-loading conditions, and critical liquid saturation and relative permeability curves in carbon nanotubes using nemd.

**Fall Meeting:**
December 10, 2014
Topics covered included nano-scale modeling of unconventional gas and liquids-rich reservoir system, improving fluid recovery and permeability to gas in shale formations, evaluation of strategies for enhancing production of low-viscosity liquids from tight/shale reservoirs, and beyond dual-porosity modeling for the simulation of fluid flow in unconventional reservoirs.

December 11, 2014
Topics covered included laboratory measurement of propped fracture conductivity in the Barnett shale, using acoustic sensor data to diagnose multi-stage hydraulic fracture treatments, enhanced in-situ assessment of petrophysical properties and kerogen spatial distribution in organic-rich source rocks using well logs, and EOR with CO$_2$ in unconventional liquid reservoirs.

More information on past meetings can be found at [http://www.pe.tamu.edu/secure/crisman/meetings2014.html](http://www.pe.tamu.edu/secure/crisman/meetings2014.html), including pdf files of the presentations and audio/video files of the meetings.

Research Menu

A menu of active and completed Crisman projects is available online at [http://www.pe.tamu.edu/crisman/projects.html](http://www.pe.tamu.edu/crisman/projects.html). Clicking on the individual project link will take you to that project’s web page, where the project number, project name, faculty advisors, and graduate students are listed. Research reports furnished by the students, along with one-page reports used in the Crisman Newsletters and the Crisman Annual, can be found on this web page. Theses, dissertations, final reports, and special topics pertaining to the project are also included, where possible.
Active Research Projects in 2015

**Nano-Scale Modeling of Unconventional Gas and Liquids-Rich Reservoir System (1.2.15)**
The objectives of this work include characterization and modeling of hydrocarbon phase behavior at the nano-/pico-volume scales; characterization and modeling of multiphase flow (gas, condensate/oil, and water) at the nano-/pico-volume scales; development of (model-based) mechanistic studies for gas and liquids-rich shale systems; and development and demonstration of model-based forecasting and estimated ultimate recovery (EUR) prediction for liquids-rich shale systems.

**EOR with CO₂ in Unconventional Liquid Reservoirs (1.7.06)**
Experimental work at Texas A&M University has resulted in new evidence supporting the idea that CO₂ may effectively extract oil from very tight core where conventional measurements of air/liquid permeability are difficult or not possible. This project will further investigate the promising potential of CO₂ injection in unconventional liquid reservoirs to determine the ultimate feasibility of this cutting-edge technology.

**Applications of CO₂ for Unconventional Reservoirs (1.7.07)**
The purpose of this research is to utilize foam as a hydraulic fracturing fluid, and develop low quality CO₂ and/or N₂ formulation that would act like high-quality foam in terms of stability, rheology, and proppant carrying capacity. Furthermore, we will perform an approach to generate nanoparticle-stabilized CO₂ foam. Nanoparticles will be used to generate and stabilize CO₂ foam instead of surfactant. This study will also cover the effect of the CO₂ injection on the porosity of CBM, permeability, and the gas recovery, and will define the optimum injection conditions and techniques to achieve the highest recovery from CBM.

**Physicochemical Interactions of Shale with Injected Water-Based Fluids (1.7.08)**
We propose to evaluate in the laboratory the factors that control imbibition of fracture fluid into source rock and to evaluate methods to maximize or minimize the retention of fracture fluid in the source rock. Further, we will examine compositional changes to fluid in contact with rock at temperature and pressure to learn what to expect in the way of salinity and scaling tendency changes plus the nature of decomposition products from organic additives.

**Propped Fracture Conductivity in Shales (2.4.10b)**
This research will focus on how the hydraulically fractured horizontal well behaves in a naturally fractured reservoir using previously developed slab source models.

**Experimental Investigation of Flow Reversal to Characterize Liquid-Loading Conditions (Tower Lab Facility) (2.4.26)**
We plan to make modifications to the Tower Lab main loop (a height 43m) in order to investigate both the sections above and below the entry point of the gas-liquid mixture. Ultimately, we wish to establish a connection between hold-up correlations and critical rate correlations. The results can be then used in coupled modeling of the well/reservoir system with automatic determination of flow direction in the individual connections (perforations).

**Using Acoustic Sensor Data to Diagnose Multi-Stage Hydraulic Fracture Treatments (2.4.27)**
This investigation will develop models to simulate acoustic signals as functions of fluid property and flow behavior during fracture treatment and during production for oil, gas and water producing wells based on fundamental physical principles. We will conduct experimental studies to provide the insights of flow characteristics to acoustic measurements and the base of possible correlations for flow distribution. We will examine the parameters that are critical in fracturing design. This will be a forward model of wellbore flow behavior in fractured wells. We will then develop a statistical inversion of the forward model to interpret the downhole flow distribution from distributed acoustic sensing (DAS) measurements.

**Novel Artificial Lift Methods to Increase Reserves in Shale and Tight Sand Gas Reservoirs (2.4.28)**
This study will address an important constraint of the ultimate recovery from shale gas and tight sand gas wells – the inability to efficiently lift water from unconventional gas wells. We propose to investigate the suitability of available artificial lift methods to most efficiently unload liquids from unconventional gas wells. We will integrate the lift methods with well structure design, and will develop fluid flow models that consider the complex flow conditions in typical shale gas and tight sand producing wells to efficiently and economically produce gas from unconventional resources.
Diagnosis of Multiple Fracture Stimulation in Horizontal Wells by Downhole Temperature Measurement for Unconventional Oil and Gas Wells (2.5.21)

This research will develop a rigorous theoretical model of mass and heat flow in a multiple fracture system, which will then be applied to both gas and oil wells in order to investigate the feasibility of the concept of using downhole temperature data measured by distributed temperature sensors during and post hydraulic fracturing to diagnose fractured well performance, and possibly, dynamic fracture geometry and conductivity, in unconventional gas wells. It will develop mathematical inversion models that translate the temperature and pressure data into descriptions of complex fracture systems.

Investigation of Fracture Fluid Performance in Oil Shale with Surfactant Additives by X-Ray Tomography Methods (2.5.22)

This research will make use of CT-scan technology to study FRAC fluid penetration into oil shale samples to quantify the effectiveness of surfactant mixtures using rate and total magnitude of penetration for determination of optimum surfactant formulations to maximize well performance after stimulation.

Quantifying Vertical Heterogeneity in Carbonate Formations using Well Logs for Improving Prediction of Acid Fracturing (2.5.24)

The objectives of this study include (a) improving permeability assessment for prediction of acid fracture conductivity by conducting rock classification, (b) introducing new rock classification techniques in carbonate formations, that are less dependent on core measurements and take into account static and dynamic petrophysical properties, as well as the effect of fluid saturations and mineralogy on well logs, and (c) characterizing the formation spatial heterogeneity using well logs and well-log-based estimates of petrophysical/compositional properties.

Analysis of Fracturing Behavior of Ultra-Tight Geologic Media Across Spatial Scales: From Fundamental Studies to Field Applications (2.5.25)

We propose to evaluate by studies that span several scales (from nano-scale visual observations of fractured surfaces to laboratory-scale investigations to simulations from lab- to field-scale) the initiation and propagation of hydraulic fractures. Our investigation will address fundamental issues to first develop statistical models associating fracture trajectory with the spatial distribution and mechanical strength of nano- to micro-fractures and inclusions, as well as with the orientation of beds and stratification to the initial stress distribution. The statistical models will be used to develop mathematical models of fracture initiation and propagation accounting for these factors, which will be tested in laboratory-scale studies before incorporation into numerical simulators of coupled flow/geomechanics describing hydraulic fracturing.

Beyond Dual-Porosity Modeling for the Simulation of Fluid Flow in Unconventional Reservoirs (3.1.24)

This research will determine if multiple porosity simulation techniques can be utilized in conjunction with multiscale and upscaling techniques to produce information which can be utilized to better understand the unconventional production process.

Molecular Simulation of Fluid Phase Behavior in Shale Systems (3.1.25)

In this project, we propose to use molecular simulation to calculate the phase behavior of petroleum fluids for the shale reservoirs. Molecular simulation provides a link between microscopic (molecular level) and macroscopic behavior of a fluid system, by numerical evaluation of fundamental equations of statistical mechanics.

Efficient Multiscale Simulation in Shale Reservoirs (3.1.26)

This project proposes to tackle the complex process of simulating unconventional reservoirs by developing a software package within the LBM framework. If successful, we will have developed new models with a solid mathematical foundation that better represent the underlying physics on a hierarchy of scales, will have developed and applied state-of-the-art high-performance computing techniques that address the multiscale nature of modeled physical processes in the presence of data uncertainties, and will have provided integrated tools and concepts for model accurate predictions, and in turn, optimized shale gas production.

Critical Liquid Saturation and Relative Permeability Curves in Carbon Nanotubes using NEMD (3.1.28)

The purpose of this project is to investigate the oil-recovery potential of lean gases and standard surfactants at the liquid-gas and liquid-water interfaces under subsurface pressure and temperature conditions representative of liquid-rich resource shales. In
addition, we would like to perform non-equilibrium molecular dynamics (NEMD) simulation studies to understand the nature of transport of these phases.


We propose a new technique for enhanced natural/induced fracture and reservoirs characterization using amplified borehole geophysical measurements by injection of nanoparticles into the formation at desired depth intervals. This will involve both laboratory and computational aspects.

**Enhanced In Situ Assessment of Petrophysical Properties and Kerogen Spatial Distribution in Organic-Rich Source Rocks using Well Logs (3.2.20)**

This project aims to develop a new technique for reliable, real-time, and in situ assessment of petrophysical properties and kerogen spatial distribution in organic-shale formations, which can have a tremendous impact on production from these unconventional reservoirs.

**Experimental Study of Confinement Effects on Hydrocarbon Phase Behavior in Nano-Scale Capillaries (3.2.21)**

In this project, a special Texas A&M University research team is going to investigate the phase change in nano-scale capillaries using experiments. The team will use two experimental approaches based upon selected “model” porous materials: 1) combination of a nanochannel device and epi-fluorescence microscopy, and 2) modulated differential scanning calorimetry to accurately measure the effect of confinement on hydrocarbon phase behavior in shale. We will then extend the experiments by modifying the model material’s surface both chemically and topographically. We will use molecular simulation to gain insight into the experimental results.

**Multi-Phase Flow in Nano-Capillaries using NEMD (3.2.22)**

In this project, we approach the mysteries of liquid-rich shale with tools based on the first principles of mechanics using atomistic modeling and molecular dynamics simulation of multi-phase flow in small capillaries using parallel computing. We also plan to extend our investigations to pressure and temperature conditions with multi-components to investigate transport in the presence of liquid-gas phases. In our group, through another Crisman funding, we have developed the expertise to design fluid mixtures including shifts due to nano-scale confinements. Hence, it is possible to charge a capillary with the desired liquid-gas saturations to use in a subsequent NEMD simulation.

**Low Salinity Water Flooding in Sandstone Reservoirs (3.4.07)**

This project investigates the ability and efficiency of low salinity water as secondary and tertiary techniques for sandstone reservoirs. Similarly, this study aims to help in understanding the mechanisms by which oil recovery is improved with low salinity water.

**Characterization and Simulation of Discrete Fracture Networks (3.5.14)**

This research will develop the characterizing and generating method of natural fracture network using an outcrop map and/or borehole data, estimate connectivity parameters of fractal discrete fracture network (FDFN), and analyze the pressure transient behavior of FDFN using fractal parameters.
Improving Fluid Recovery and Permeability to Gas in Shale Reservoirs

Abstract
Despite all the advantages of slickwater fracturing, such as low cost, high possibility of creating complex fracture networks, and ease of clean-up, large quantities of water are still left within the reservoir after flowback. Invasion of aqueous fracturing fluids can reduce the relative permeability to gas and thereby cause a water blockage.

Compared to conventional surfactants that lose activity after contacting the first few inches of the formation due to adsorption to the rock surface, microemulsions with advantage of having combined effect of microemulsion-forming surfactants and organic solvents, outperform pure organic solvent or pure surfactant when used independently. Microemulsions can provide maximum surface area of contact with the formation due to their structure and can increase penetration and cleaning efficiency.

Objectives
Evaluate microemulsions as a treatment chemical solution in fluid recovery and gas permeability enhancement tests.

Approach and Accomplishments
The research completed in this study had been designed to assess the performance of microemulsions when used as an additive to the fracturing fluid to stimulate the gas bearing formations. Microemulsions formulated with a blend of anionic surfactant, nonionic surfactant, oil and water were used to prepare the microemulsion systems. The average size of the microemulsion-V droplet (as received) was detected by transmission electron micrographs (TEM). The droplet size of the treatment fluid, 0.2 wt% ME-V in 2 wt% KCl, couldn’t be detected by TEM.

A fully automated tensiometer which featured a Wilhelmy-type wetting force measurement technique, was used to measure the surface tension of the chemicals at different concentrations ranging from 0.05 to 2 wt% at 75°F. Surface tension was measured for microemulsions and the results were compared with the surface tension of three surfactant solutions including a non-ionic, a cationic, and an anionic surfactant that were prepared at the same concentration as the microemulsions.

Thermal stability of the microemulsions was studied using high pressure and high temperature (HP/HT) aging cells for temperatures up to 400°F. The 100 ml of 0.5 wt% microemulsion solutions were prepared in deionized water. The microemulsions were aged in the oven for 24 hours at 150°, 250°, and 400°F. Surface tension was measured before and after heating to identify the thermal stability of the solutions. Two series of compatibility tests were done to assess the potential microemulsions for the coreflood experiments. The first one was the brine compatibility test, in which the microemulsions were mixed with 2 wt% KCl at a concentration of 0.2 wt% of the microemulsions in 2 wt% KCl. In the second test, the compatibility of the prepared microemulsion treatment fluids with condensate were tested. The compatibility tests were investigated visually at room temperature for any color changes or phase separation in the fluids.

Bulk analysis and clay mineralogy of three different shale rocks, including outcrop of Barnett shale, Marcellus shale, and reservoir rock of the New Albany shale, were conducted using X-ray diffraction (XRD) to characterize the rocks. Mineral composition of Bandera sandstone core used in coreflood tests was also determined by XRD.

The zeta potential analyzer (ZetaPALS, Brookhaven Instrument Corporation) was used to measure the zeta potential. Zeta potential measurement can help with understanding
and controlling the suspension of colloids in the solution. The magnitude of zeta potential shows the degree of repulsion between adjacent, similarly charged particles in dispersion.

Shale rocks with a particles size of 140 mesh corresponding to an average size of 105 μm were used to study fluid-rock interactions in zeta potential tests. The fluids were 0.5 wt% of three microemulsions and three types of surfactants in deionized water. The instrument measured di-electrophoretic mobility and then calculated the zeta potential. All experiments were conducted at room temperature.

The wetting characteristics of solid surfaces were evaluated by contact-angle methods. The high-pressure/high-temperature (HP/HT) drop shape analysis system was used to determine contact angle from the shape of sessile drops.

Coreflood experiments were performed in order to investigate and compare the potential of microemulsions to improve gas relative permeability and fluid recovery in the presence of synthetic condensate and brine. The experiments were performed on Bandera sandstone cores saturated with 2 wt% KCl. The conditions of all experiments were: temperature 165°F, back pressure 700 psi, overburden pressure 1800 psi. Two different microemulsions were tested and compared with the results of the permeability improvement for the mutual solvent and fluorocarbon polymer treatment solutions. Another set of coreflood tests were run to compare the microemulsions with surfactant solutions in improving gas permeability in Banderas sandstone cores. Salinity and aging effects were studied to investigate factors that could have an effect on fluid-rock interactions.

The average size of the microemulsion-V droplet (as received) was determined to be in the range of 30-60 nm. This is an important factor to be considered in low permeability reservoirs where small pore-throat will be plugged by injected fluid. A smaller value of microemulsion droplet size as compared to the surfactant droplets results in a good infectivity and penetration without filtration to the formation.

Surface tension was less for microemulsions as compared to the cationic, anionic, and non-ionic surfactants at concentrations ranging from 0.05 to 2 wt%. Longer interfacial contact and higher surfactant solubility capacity of microemulsion compared to the surfactants could be an explanation of the results.

Insignificant change in surface tension values of microemulsions after being aged for 24 hours at 150°, 250°, and 400°F showed high thermal stability of the microemulsions. No phase separation, precipitation and color change was observed after being at high temperatures up to 400°F for 24 hours.

Two microemulsions, ME-V and ME-E, showed compatibility with the brine solution and condensate. Microemulsion ME-N was incompatible with both the brine solution and the condensate.

The results of the XRD on three shale rocks showed that Barnett had the most amount of clays including kaolinite and Illite and some smectite. Marcellus had the most amount of carbonate, and New Albany shale had the most amount of minerals which main part was quartz, in addition to feldspar, pyrite, barite and other minerals. Mineralogy and clay content of the rock plays an important role in fluid-rock interactions.

The results of the zeta potential tests for microemulsions showed that the ME-V has the lowest negative value of zeta potential compared to the other microemulsions for all different rock types, which resulted in least water-wettability characteristics when compared
to the other microemulsions. The values of zeta potential for Barnett and New Albany shale were the highest compared to the other rock types due to high clay content in these rocks as determined by XRD. The results indicated that the value of zeta potential depends on the ionic strength of the solutions and depends on the resultant charges on the rock particles. Zeta potential and surface charges are affected by the pH. The pH for all different rocks in different fluids were measured to be around 7.

Contact angle values showed water-wettability characteristics for all chemicals including two microemulsions and three surfactant solutions. The results showed that microemulsion ME-V at concentration of 0.2 wt% in 2 wt% KCl had the contact angle of 49.5° which showed the least water-wet characteristics. The brine solution, 2 wt% KCl, with contact angle of 18.9° showed the most water-wet tendency on Barnett shale rock at 165°F and atmospheric pressure compared to the other tested chemicals. Less water-wettability characteristics will result in more reduction of capillary pressure and higher productivity in gas bearing formations.

When compared to mutual solvent and fluoropolymer surfactant, which caused damage to the cores, both microemulsions ME-V and ME-E improved the effective gas permeability. The highest permeability improvement was achieved by an injection of 0.2 wt% ME-V in 2 wt% KCl into the 20-in. Bandera sandstone core, while mutual solvent and fluoropolymer surfactant solutions caused damage to the core.

Salinity effect results for 0.5 wt% microemulsions in 2 wt%, 5 wt%, and 10 wt% of NaCl, KCl, CaCl2, and MgCl2 showed that microemulsion-N was not compatible with brine solutions at low and high salt concentrations at 75°F. Phase separation was observed after mixing microemulsion-N with brine solutions. However, no precipitation, phase separation, and color changes were observed for the ME-V and ME-E.

Surface tension measurement results for microemulsions ME-V and ME-E at 75°F showed that increasing the concentration of the salts in the treatment fluid did not change the surface tension values significantly. These two microemulsions had low surface tensions at 0.5 wt% of chemicals in 2 wt%, 5 wt%, and 10 wt% of NaCl, KCl, CaCl2, and MgCl2.

Aging the rock particles in contact with different treatment solutions, showed an increase in the concentration of tested elements, including Ca, Mg, Al, and Si in the solutions; that can be an explanation of high total dissolved solid in the flow back fluid after completion.
Nano-Scale Modeling of Unconventional Gas and Liquids-Rich Reservoir Systems

Abstract
Shale reservoirs are unconventional reservoirs that play an important role as resources of future energy in the U.S. Some studies have been done in the oil and gas industry to describe how hydrocarbon is stored and flows through ultra-small pores in the shale reservoirs. Most of these studies were derived by borrowing and modifying techniques used for sand or conventional reservoirs. The common pore size distribution of the shale reservoirs is approximately 1-20 nm (Clarkson et al., 2011). In such a confined space, interaction between the wall of the container (i.e., shale and kerogen) and the contained fluid (i.e., hydrocarbon) becomes significant to the fluid’s behavior. Orientation and distribution of fluid molecules in the confined space are different from those of the bulk fluid. This can cause the change of fluid properties such as critical temperature and pressure, diffusion coefficient and viscosity.

This research will provide a detailed study of the changes of pressure/volume/temperature (PVT) properties and flow behavior of fluid in the shale reservoirs. Mechanistic studies and development of model-based forecasting and estimated ultimate recovery (EUR) prediction for liquids-rich shale system are also included in this project.

Objectives
» Characterize/model hydrocarbon phase behavior at the nano-/pico-volume scales.
» Characterize/model multiphase flow (gas, condensate/oil, and water) at the nano-/pico-volume scales.
» Provide illustrative (model-based) mechanistic studies for gas and liquids-rich shale systems.
» Develop and demonstrate model-based forecasting and EUR prediction for liquids-rich shale system.

Approach
Grand Canonical Monte Carlo (GCMC) and Molecular Dynamics (MD) simulations are used to study molecular fluid behavior and thermodynamic properties of hydrocarbon in confined spaces such as pores in shale reservoirs. GCMC simulation is mainly used to determine the number of molecules accommodating in the system whose chemical potential equals that of the given bulk system’s at constant pressure and temperature. The primary outcomes from the GCMC simulations are isotherms of pure components and mixtures of hydrocarbons in confined space. As a result, the fluid thermodynamic properties such as vapor pressure, critical pressure and temperature and phase diagram can be yielded.

The MD simulation is based on the integration of classical mechanics equations (Newton’s second law) for a system where molecules interact according to interatomic potentials that are functions of their relative positions. The outcome of the simulation is a trajectory of molecular configurations (positions and velocities of each molecule). From such trajectory, using statistical thermodynamics, all the thermodynamic properties and some transport properties can be evaluated.
The main purposes of employing the MD simulation are to help understanding how fluid molecules move in this system and to derive fluid dynamics properties (i.e. diffusion coefficient and viscosity). In addition, it can be used to confirm structural properties of the PVT state points calculated from the GCMC simulations.

A slit graphite pore is used to represent the pore inside kerogen in shale reservoirs as illustrated in Fig. 1. The separation between the two graphene sheets is varied to study the effect of confinement on the PVT properties of hydrocarbon mixtures.

**Accomplishments**

Figs. 2a, 2b and 2c illustrate the phase diagrams of the confined methane-ethane mixtures in a slit pore graphite with 3.0 nm, 5.0 nm and 7.0 nm of separation, respectively. Comparing with the phase diagram of the bulk mixture as shown as Fig. 2d, it can be noted that the phase diagram of the confined mixture in the smaller pore is more deviated from those of the bulk. It confirms our conclusion where the interaction between rock and fluid molecules become less significant in the larger pore.

Fig. 3 illustrates isotherms of the confined propane in 2.0 nm, 3.0 nm and 4.0 nm, respectively. To derive isotherms of long-chain alkane, Configurational-Biased Grand Canonical Monte Carlo (CBGCMC) simulation is implemented. This approach allows variation of bond angles (i.e., bending and torsion where the regular GCMC simulation does not). Both critical pressure and temperature of the confined fluid can be read from the isotherm plots. The critical properties of the confined propane in the different pore sizes are summarized in Table 1.

**Collaborations**

This study was done in collaboration with Prof. Perla B. Balbuena, Department of Chemical Engineering, Texas A&M University.

**Significance**

This research will help us better understand how fluid behave in shale reservoirs. Consequently, more accuracy of production forecast, EUR prediction, and hydrocarbon in-place can be yielded.

(continued on next page)
Future Work

» Continue working to derive the critical properties of n-alkane hydrocarbon pure components.

» Continue working on finding phase diagrams of confined ternary mixtures of hydrocarbons.

References and Related Publications


<table>
<thead>
<tr>
<th>Separation (H), nm</th>
<th>Critical temperature ($T_c$)</th>
<th>Critical pressure ($p_c$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.0</td>
<td>256 K or 1.1°F</td>
<td>13 kPa or 2 psi</td>
</tr>
<tr>
<td>3.0</td>
<td>322 K or 119.9°F</td>
<td>500 kPa or 73 psi</td>
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<tr>
<td>4.0</td>
<td>348 K or 166.7°F</td>
<td>1360 kPa or 197 psi</td>
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<tr>
<td>Bulk Fluid</td>
<td>369.8 K or 206.0°F</td>
<td>4250 kPa or 616 psi</td>
</tr>
</tbody>
</table>

Table 1–Critical properties of confined propane in different pore sizes.
Simulation Model for Oil Shale Thermal Decomposition Followed by Oil and Gas Production

Abstract
Oil shale is a vast energy resource, but it has not been produced commercially due to the necessity of heating. The organic matter in the oil shales, kerogen, releases abundant amounts of hydrocarbon when it absorbs sufficient heat. We investigated the in-situ upgrading processes which are applicable for the majority of oil shale deposits. They were Shell In-situ Conversion Process (ICP), ExxonMobil Electrofrac, and Texas A&M (TAMU) Steamfrac. We investigated these three processes by using our rigorous simulator developed for the kerogen pyrolysis in the in-situ upgrading of oil shales, and estimated the energy efficiency and process economics of each process.

Objectives
The overall goals of this research are to develop a fully functional simulator for the oil shale in-situ upgrading, to apply it to the diverse in-situ upgrading processes, and to evaluate the productivity, energy efficiency and economics. With these, we can determine the success of each process.

Database development will deal with the geological structure of the oil shale, physical properties of the oil shale rock, and kinetic reactions of the in-situ upgrading process.

Simulator development will consider the mathematical description of the mass conservation, energy conservation and chemical reactions equations, interaction between fluids and porous medium, phases and components thermodynamics, equation of state, fully implicit solution, and numerical description of the fractured medium.

Validation of the simulator by reproducing Shell ICP field production data deals with the sensitivity analyses of the effect of pre-existing fracture network, oil shale grade (organic matter content), fracture domain permeability, and formation thermal conductivity.

Application of the simulation cases involves each process: Shell ICP cases in a pattern by using several temperatures of the multiple electric heaters, ExxonMobil Electrofrac cases by using several electrical conductivities of the proppant, and TAMU Steamfrac cases with huff-and-puff processes by using diverse numbers of wells and continuous injection and production methods, and comparison of the energy efficiency and net present value (NPV) among the three processes.

Approach
We developed a fully implicit reservoir simulator for the kerogen pyrolysis in the oil shale in-situ upgrading by expanding Texas A&M Flow and Transport Simulator (FTSim). It describes oil shale thermal decomposition and subsequent system changes, considering 6 kinetic reactions which result in 4 phases and 10 components. The simulator involves mass transport and heat flow, and accounts for phase equilibrium and phase transition thermodynamics. We conduct the diverse simulation cases with the Shell ICP, ExxonMobil Electrofrac and TAMU Steamfrac, which implement the in-situ upgrading by using multiple electric heaters, the injection of

(continued on next page)
Table 2–Simulation results of the application cases

<table>
<thead>
<tr>
<th></th>
<th>Shell ICP1</th>
<th>Shell ICP2</th>
<th>Shell ICP3</th>
<th>Exxon1</th>
<th>Exxon2</th>
<th>Steamfrac1</th>
<th>Steamfrac2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Duration</td>
<td>320 days</td>
<td>240 days</td>
<td>340 days</td>
<td>7 years</td>
<td>7 years</td>
<td>900 days</td>
<td>555 days</td>
</tr>
<tr>
<td>Remaining kerogen (%)</td>
<td>0</td>
<td>4.10</td>
<td>2.66</td>
<td>97.4</td>
<td>78.8</td>
<td>99.78</td>
<td>45.9</td>
</tr>
<tr>
<td>Liq. Org. Prod. (STB)</td>
<td>283</td>
<td>942</td>
<td>1,415</td>
<td>114</td>
<td>1,370</td>
<td>23.30</td>
<td>2,760</td>
</tr>
<tr>
<td>Gas. Prod. (MSCF)</td>
<td>3,386</td>
<td>4,310</td>
<td>2,871</td>
<td>85</td>
<td>1,340</td>
<td>0.66</td>
<td>550</td>
</tr>
<tr>
<td>Produced HC (BOE)</td>
<td>883</td>
<td>1,057</td>
<td>1,542</td>
<td>130</td>
<td>1,610</td>
<td>23.33</td>
<td>2,860</td>
</tr>
<tr>
<td>Energy efficiency (%)</td>
<td>51.6</td>
<td>106</td>
<td>144</td>
<td>8.59</td>
<td>71.6</td>
<td>8.79e-3</td>
<td>67</td>
</tr>
</tbody>
</table>

highly conductive proppant into vertical fractures, and steam injection into vertical fractures, respectively (Fowler and Vinegar 2009; Olgaard et al. 2009; Thoram and Ehlig-Economides 2011).  

**Accomplishments**

We validated our simulator by reproducing the field production data of Shell ICP implemented in the Green River Formation from 2004 to 2005 (Vinegar 2006). We conducted 400 days of heating and production simulation, and had good matches of the simulation results and the field production data as shown in Fig. 1.

The validated model is a naturally fractured reservoir, and has an oil shale grade of 25 gal/ton, fracture domain permeability of 150 md, and a formation thermal conductivity of 2.0 W/m-K. The sensitivity analyses results on the reservoir parameters are shown in Table 1.

In the application cases, we conducted simulations with diverse factors affecting the productivity and energy efficiency in the multiple pattern of each process. In the Shell ICP, ExxonMobil Electrofrac and TAMU Steamfrac methods, we investigated the effects of the heater temperature, electrical conductivity of the proppant, and steam injection strategy, respectively. We summarized the simulation results in Table 2. Shell ICP cases indicate the heater temperatures of 650°, 625°, and 610°F, ExxonMobil Electrofrac cases indicate the proppant electrical conductivity of 2.055E5 and 1.989E7 Ω-1m-1, and TAMU Steamfrac cases indicate the huff-and-puff method with 1 well, and continuous steam injection and simultaneous production, respectively. In the computation of NPV, we observed that the highest Capex in the Shell ICP and the highest Opex in the TAMU Steamfrac, due to the cost for a huge number of wells and the cost for steam injection, respectively.

**Significance**

Challenges exist in the thorough description of the kerogen pyrolysis in the upgrading process because it involves a series of complex and sensitive reactions, and results in a large number of fluid and solid products. Our newly developed simulator provides a robust tool for the kerogen pyrolysis and evaluation of the diverse processes of the in-situ upgrading of oil shales. The simulation cases provide the guidelines for the successful hydrocarbon production from the oil shales by expecting the optimal strategy of each process.

**References and Related Publications**


EOR with CO₂ in Unconventional Liquid Reservoirs

Abstract
Experimental work at Texas A&M University has resulted in new evidence supporting the idea that CO₂ may effectively extract oil from very tight core where conventional measurements of air/liquid permeability are difficult or not possible. This project will further investigate the promising potential of CO₂ injection in unconventional liquid reservoirs to determine the ultimate feasibility of this cutting-edge technology.

Objectives
To observe CO₂ and hydrocarbon gas diffusion into ultra-low porosity and permeability oil shale cores and how the process increases the ultimate oil recovery

Approach
Physical simulations will be performed with x-ray computer tomography equipment to track changes made by CO₂ in unconventional liquid reservoir cores from various plays.

The petrophysical properties of the cores from different unconventional plays will be determined in the laboratory by calculating end point saturations and the recovery factor of the CO₂ method. Laboratory methods will be used to determine the petrophysical properties on our hydrocarbon-bearing unconventional cores, including, but not limited to: helium porosimeter, thin section analysis, and pressure decay permeability measurement.

We will perform direct gas injection prior to using the glass beads approach to highlight the advantages of our glass beads method.

Accomplishments
Two physical simulations with x-ray computer tomography (CT) and a unique approach utilizing glass beads to simulate hydraulic fracturing at reservoir temperature and pressure were successfully performed in our laboratory on preserved sidewall cores with negligible permeability. A significant amount of oil was recovered by CO₂ method, and the changes in saturation profile during the corefloods were precisely captured by CT scanning.

Effective porosity measured from helium porosimeter of the two cores were 17% and 18%, respectively. Porosity values were estimated via thin section analysis and point count technique, with the values of the two cores as 13% and 15%, respectively.

Direct hydrocarbon gas and CO₂ injections were performed in cores from a different play at reservoir temperature and pressure. Results indicated the permeability of the rock is too low for gases to flow directly through the core at the experiment temperature and pressure.

Significance
The CO₂ diffusion into the porous media and solvent extraction of the hydrocarbons was very promising for enhanced recovery in unconventional liquid reservoirs when permeability is too low to allow regular displacement of fluids.

(continued on next page)
**Future Work**

*Experimental*

» Perform continuous CO₂ injection with cores from different unconventional plays at different conditions of pressure and temperature to reproduce and draw definite conclusions on the extent of the success of the recovery mechanism.

» Record permeability measurements using pressure decay method. A reconstruction of 3D porous media using a geostatistical approach from thin sections should be attempted for estimating permeability.

» Establish an easy-to-duplicate laboratory protocol.

*Numerical modeling*

» Build a fine scale core model to match the experimental results.

» Perform a sensitivity analysis.

» Evaluate field application economic feasibility.

**References and Related Publications**


Applications of CO₂ for Unconventional Reservoirs

Abstract
The critical micelle concentration (CMC) value is one of the important parameters of a surfactant. Before reaching the CMC value, the surface tension decreases as surfactant concentration increases. After reaching the CMC value, the surface tension remains constant or changes with a low slope. Moreover, the surfactant concentration is a critical step in preparing more stable foam. Most surfactants must be used above the CMC value in order to obtain proper properties for forming foams. Consequently, this part of the project completes the previous part to aim for optimization of surfactant concentration to obtain the CMC value in order to produce a more stable foam.

Objectives
The main purpose of this report is to study the effect of surfactant concentration at 302°F for 3 and 5 wt% of NaCl on the CMC value of alpha olefin sulfonate (AOS) as an anionic surfactant. In the previous report, the CMC value was evaluated at temperatures ranging from ambient conditions to 212°F, while the salt concentration was 1 wt% of NaCl.

Approach
Equilibrium surface tensions of different concentrations of AOS surfactant at various temperatures (ambient to 302°F), pressures (77 to 435 psi), and salt concentrations (1 to 10 wt%) are measured with a drop shape analysis system using a pendent drop method. A sharp change in the plot of log (AOS concentration) versus surface tension defines the CMC value. The surface tension is normally constant above the CMC value.

Accomplishments
Fig. 1 shows the results of measuring surface tension between surfactant and CO₂ gas as a function of surfactant concentration for various pressures and temperatures. Based on the experiments indicated and the results obtained for the experiments, the surface tension decreased as surfactant concentration increased (Fig. 2) for all electrolyte concentrations until it reached a minimum (Fig. 3). The surface tension values changed slightly after this minimum and remained constant afterward. The minimum point is known as a CMC value. The CMC value for the CO₂/AOS solution was 0.025 wt% at ambient conditions in the presence of 1 wt% NaCl. Furthermore, the CMC value decreased as the salt concentra-

(continued on next page)
Fig. 2–Surface tension as a function of pressure for 3 wt% NaCl at 0 wt%, 0.005 wt%, 0.05 wt% and 1 wt%.

Fig. 3–Comparison between surface tension for a given salinity at various pressures.

Significance
The choice of surfactant concentration is a critical step in preparing a more stable foam. In the present report, a new foaming solution has been introduced in order to optimize surfactant concentration in formation of stable CO$_2$-foam. The surface tension measurements were obtained using the drop shape analysis technique for pendant drop method. The CMC value increased, from 0.025 to 0.2 wt%, as the temperature increased, from ambient to 302°F, using 1 wt% of NaCl and, it also decreased, from 0.25 to 0.05 wt%, as the salt concentration increased, from 1 to 5 wt%.

Future Work
Surfactant will be degraded at high temperature and salinity. Adding nanoparticles to an AOS solution is one of the solutions to decrease surfactant degradation. Therefore, future work will include more experiments on surface tension to find the CMC value between CO$_2$ and a mixture of AOS solution and nanoparticles at various conditions to investigate and compare the nanoparticles effect on the CMC value and surface tension.
References and Related Publications


Fig. 4–Surface tension versus AOS concentration for 1, 3, and 5 wt% of NaCl

Fig. 5–Comparison of CMC value versus temperature for 1 and 5 wt% of NaCl

Fig. 6–Effect of temperature on surface tension at different pressures for 0.025 wt% of AOS and 1 wt% NaCl (77 to 302°F)
Sequestration of Carbon Dioxide in Coal with Enhanced Coalbed Methane Recovery

Abstract
Geological sequestration of CO₂ in coal seams became an attractive carbon sequestration technology for two reasons: the injection of CO₂, or mixtures of CO₂ and N₂, enhances methane production from coalbeds (ECBM) in addition to storing the CO₂. The primary recovery of coalbed methane is by means of reservoir pressure depletion. Reduction in reservoir pressure derives the fluids from the coal matrix to the cleats then towards the wellbore, but there is a practical and economic limit on the extent to which reservoir pressure can be reduced. The injection of nitrogen and/or carbon dioxide into the coalbed methane reservoirs can materially improve gas recoveries. Injection of carbon dioxide into deep coal seams has the potential to enhance coalbed methane recovery, while simultaneously sequestering a greenhouse gas.

Objectives
The main objectives of this research are to:

» Examine the effect of the injected fluid, formation salinity on formation permeability, wettability, and coal adsorption isotherm.

» Evaluate the effects of well spacing, injection gas composition, injection rate, coal de-watering prior to gas injection, and production pressure on methane production rate, cumulative production, time to breakthrough of the injected gas, and CO₂ sequestration.

» Correlate the optimum injection conditions and techniques to achieve the highest recovery from CBM.

Approach
We will characterize coal by measuring its physical and chemical properties.

We will use contact angle, Zeta-potential, and adsorption isotherm measurements to investigate coal wettability.

We will conduct a series of coreflood experiments in order to: measure the coal permeability (steady state method and pulse decay method) and the adsorption capacity with different injected gases, measure the water salinity effect on the residual water saturation and the displacement efficiency, and measure the change in methane production rate and cumulative production at different injection conditions.

We will collect and analyze core effluent samples by using gas chromatography.

We will develop an integrated model to match the experimental results, and use it as a history matching tool to match the reservoir production data to estimate the gas inplace, permeability, and Langmuir constant of the formation. These estimated parameters can be used to predict the performance of the formation.

Accomplishments
The contact angles in the coal–water–CO₂ system were measured using a captive bubble method at elevated pressure conditions (from 14.7 to 700 psi) at different salt concentrations and type.

The manometric isotherm adsorption measurements were conducted to confirm the effect of water salinity on the CO₂ adsorption behavior on coal surface.

The zeta potential measurements for different salt concentrations were
conducted versus pH.

**Significance**

As the water salinity increased, the CO₂ solubility in water decreased, the contact angle increased, and the NaCl salt had a greater effect on the contact angle values than CaCl₂ and MgCl₂ salts (Fig. 1).

The adsorption isotherm increased as the NaCl concentration increased, and the Langmuir adsorption volume changed from 1330 scf/ton in the deionized water case to 1780 scf/ton in the 20 g/L NaCl brine (Figs. 2 and 3).

The addition of inorganic salts (NaCl, MgCl₂, and CaCl₂) decreased the absolute value of the zeta potential (Fig. 4).

**Future Work**

More CO₂ sequestration experiments will be conducted to examine the effect of water salinity on the storage capacity of coal. Also, coreflood experiments will be conducted in order to accomplish the following: measure the water salinity effect on the residual water saturation and the displacement efficiency, and measure the change in methane production rate and cumulative production at different injection conditions.

**References and Related Publications**


Physico-Chemical Interactions of Shale with Injected Water-Based Fluids

Abstract
The purpose of this work is to investigate the physical and chemical changes to the rock and fracturing fluid once they come in contact with each other. Outcrop samples from the Eagle Ford, Barnett, and Marcellus shales were collected and analyzed for mineralogy, organic content, etc. Those were exposed to linear polymer solutions and a lab prepared cross-linked gel. Results from this work show significant interaction between the rock and the fluids investigated. Polymer adsorption and thermal degradation were identified as two mechanisms to determine the fate of the linear polymers investigated. Additionally we show that, in rocks with high organic content, the oxidizing breakers used in breaking the cross-linked gels might be better spent on oxidizing the organic content of the rock.

Objectives
» Determine the fate of fracturing fluid polymers once they come in contact with the rock
» Determine whether such interactions between the rock and the cross-linked gel cause any changes to the behavior of such fluids.

Approach
We obtained cross-linked gel components from a service company. Additionally, different polymers and chemicals were purchased from different vendors. Rock samples were crushed and sieved to a mean particle size of 2 mm. Those rock samples were then exposed to different polymer solutions and a cross-linked gel inside metal aging cells lined with Teflon® tubing. The cell was purged with nitrogen gas up to 100 psi to simulate downhole conditions and prevent aerobic bacteria from developing. Those cells were then placed inside a roller oven set at 115°F. This temperature was selected to inhibit thermal degradation of the polymer. The viscosity of the solution was measured before and after exposing the solution to the rock. A percent viscosity reduction was obtained. This reduction in viscosity was interpreted as a qualitative indicator of the amount of polymer adsorbed onto the surface of the rock.

Accomplishments
We have shown that significant losses of the polymer solution viscosity could occur due to polymer adsorption when reservoir temperature is relatively low (below ~120°F), as shown in Fig. 1.

Additionally, thermal degradation can also have a significant impact on viscosity reduction in reservoirs with high temperature. We performed experiments under 250°F (show in Fig. 2) and almost 80% of this viscosity was lost in the blank sample.

We also studied the impact of brine additives on polymer adsorption. As shown in Fig. 3, all the brines studied had reduced polymer adsorption, with Mg2+ having the highest impact because water soluble polymer molecules tend to uncoil less in solutions with higher ionic strength. In such cases (brines vs. fresh water), there are fewer polymer molecules available to bond to the clay surface, leading to weaker bonding to that surface and probably less total bonding of the polymer to the surface, which is consistent with observations that less polymer bonding to clay surfaces occurs in brines vs. fresh water.

Finally, some work was done to determine whether the interactions between a guar-based borate-cross-linked fracturing fluid and the rocks caused any changes to the behavior of such fluids (Fig. 4). This cross-linked gel contained oxidizers (sodium bromate and am-
monium persulfate). It is easy to observe that the viscosity of the broken gel for the Barnett shale case is higher than the rest of the cases. At this point, we were prompted to read the study done by Anderson (1963) where sodium hypochlorite was used as an oxidizing agent to remove the organic content from soil samples. The procedure outlined in Anderson (1963) was followed to remove the organic content (described in Appendix A) from crushed Barnett Shale samples. Commercial bleach (6% sodium hypochlorite) was used. The treated sample was then exposed to a cross-linked fluid under the same conditions (100 psi; 200°F) and the viscosity of the broken gel was measured at 20 rpm (Fig. 5). The viscosity of the broken gel in the case of the treated sample was less than the untreated sample. This might significantly delay wellbore clean-up post fracture operation, which could severely impact cash-flow. Additionally, the presence of a viscous fluid inside the fracture indicates the presence of a high molecular weight polymer. This could in turn cross-link in the presence of borate ions and high pH, both of which are presumed to be present inside the fracture according to Agim (2014). If cross-linked gels are left unbroken for extended periods of time, they will keep cross-linking to a point where the gel would expel all the water out, leaving a highly concentrated solid polymer concentrate inside the fracture. This could result in severe damage to the proppant pack conductivity (Marpaung et al. 2008).

**Significance**

There are several concerns associated with using water-based fracturing fluids. Some of those concerns are subsurface (Abdulsattar et al., 2015), while others are environmental. The latter are mainly concerned with sourcing water for fracturing fluids, as well as disposing of flowback water. Therefore, it would make sense to make use of the water that comes back up to the surface after the well is put online, post fracturing operations. This fluid must also cause minimum damage to the formation it targets and the proppant pack. Prior to either of these requirements, it is necessary to understand the fate of the organic and inorganic additives that are added to the fracturing fluids in the first place. Such knowledge will help create fracturing fluids that are less damaging and hopefully reduce water treatment cost. The significance of polymer adsorption itself has not yet been determined, however several hypotheses can be made as to whether it has positive or negative impacts. More research will be required.

**References and Related Publications**


Optimization of Horizontal Well Performance in Low-Permeability Gas Reservoirs

Abstract
In low-permeability gas reservoirs, horizontal wells with hydraulic fracturing have been used to further extend the contact between wellbores and reservoir. The role of natural fractures commonly found in shale reservoirs are highlighted, especially as the shale reservoirs become important as a new energy source. Natural fractures can create a network of connectivity within the reservoir and potentially improve the production by enhanced contact with the reservoir. This research will be focusing on how the hydraulically fractured horizontal well behaves in a naturally fractured reservoir using previously developed slab source models.

Objectives
The research proposed in this project will use a previously developed model to predict fractured horizontal well performance in tight gas reservoirs in order to:

» develop the slab source and superposition method as a solution to the problem of pressure and flow distribution in a closed, rectangular reservoir for several boundary conditions
» predict the performance for horizontal wells and horizontal wells with multiple transverse fractures
» adopt a suitable natural fracture generation model to predict the performance of hydraulically fractured wells in a natural fracture system
» improve the computation efficiency of previously developed slab source model to accommodate realistic occurrence of natural fractures combined with hydraulic fractures
» establish a relationship between well performance and the characteristics of natural fractures

Approach
The semi-analytical slab source model developed by Lin and Zhu (2010) will be used to predict well performance of hydraulic fractured well system. To reflect the heterogeneous nature of natural fractures, the generating discrete fracture networks developed by Kim and Schechter (2009) will be adopted.

Accomplishments
A semi-analytical slab source model was developed by Lin and Zhu (2010) through this project to a hydraulic fractured well system to predict well performance. This method is flexible and can be easily applied.

The model was tested to predict the performance of multiple stages of fractures in a horizontal well considering the influence among the fractures.

Kim and Schechter (2009)’s Fractal discrete fracture network (FDFN) model was developed originally to incorporate the various scale-dependent data, such as outcrop, log and core. This model was successfully combined with the slab source model to reproduce the realistic natural fracture patterns.

A more realistic occurrence of natural fracture was modeled.

Adsorbed gas estimation of shale reservoirs was included in the previous slab source program. Langmuir’s isotherm and material balance was used to predict the adsorption gas production.
The calculation efficiency was greatly improved by introducing parallelization of the source term calculation.

**Significance**
Honoring the explicit distribution of natural fractures can be done by using combined source function method.

**Future Work**
Verification of this method with commercial software will be studied.
Experimental Investigation of Flow Reversal to Characterize Liquid-Loading Conditions

Abstract
This work focuses on situations of particular significance in natural gas producing wells, when annular to churn flow-pattern transition brings about drastic hold-up increase, leading to a rich group of phenomena in the field known as “liquid loading”. Under circumstances believed to precede liquid loading, the still steady-state and stable liquid holdup may be several folds larger than the inlet volumetric fraction of the liquid, due to partial flow reversal. This leads to increased resistance in the pathway of the produced gas, triggering instability in the coupled well-reservoir system and ultimately causing the end of the natural flow of gas from the reservoir. Extensive studies have been conducted in this particular area, where the actual choice is to accept the hypotheses of critical rate correlation derived using data solely from actual producing wells. However, the richness of the related phenomena in the gas field comes from the interaction of multi-phase flow in the well and in the underlying porous media. In this study, we investigate the flow reversal phenomena, its consequence to the hold-up value, and the corresponding countercurrent flow. Furthermore, the results can be used in the coupled modeling of well-reservoir system.

Objectives
» Investigate the performance of various liquid hold-up prediction methods in the presence of partial flow reversal.
» Investigate the characteristic of flow reversal and the amount of liquid flowing downward with various gas and liquid mass fluxes.
» Develop a new hold-up prediction method, specifically designed for gas wells experiencing annular to churn flow transition when flow reversal occurs.
» Investigate the chaotic behavior (oscillation) of the flow during annular to churn flow transition.

Approach
Two groups of two-phase flow experiments are performed in a modified transparent 42-m long, 0.048-m ID vertical tube system. The first experiment is conducted by using the inlet at z = 0 m while the second is at z = 7 m. In the first experiment, volumetric liquid hold-up is measured by closing inlet and outlet valves in a synchronized manner during stabilized state, trapping the liquid inside the test section. In the second experiment, we investigate the flow in both sections above and below the entry point located at z = 7 m. The amount of liquid flowing downward is measured with different inlet configurations. In both type of experiments, absolute pressures and liquid film thickness are measured at several vertical locations with various sampling frequencies. The gas and liquid mass flux intervals correspond to possible situations in natural gas producing wells where volumetric liquid rates are moderate or low, and (initial) volumetric gas rates are high, while mass fluxes are of the same order.

Accomplishments
A new hold-up prediction method was developed specifically for conditions affected by
partial flow reversal. As shown in Fig. 1, the proposed correlation reproduces the experimental data with good accuracy.

Time-series analysis was performed to investigate the chaotic behavior (oscillation) of the flow regimes. Fig. 2 shows the spectral density of the absolute pressures measured at three different locations. The results indicate the existence of dominant frequencies for various flow regimes.

Liquid accumulation rates were measured utilizing the inlet located at \( z = 7 \) m with 45-degree angles of pipe entering the main tube section.

**Significance**

This research will help us to understand the flow reversal phenomena, which may have a strong relationship to the occurrence of liquid loading. The new hold-up model derived from the larger scale experimental facility can be used in coupled modeling of the well/reservoir system with automatic determination of flow direction. The experimental results of liquid deposition rate provide relevant information considering a comingle production from different perforation zones.

**Future Work**

The existing inlet located at \( z = 7 \) m with the 45-degree angle pipe entering the main tube section will be modified to the angle of 0 degrees (pipe inlet perpendicular to the main tube section). The accumulation rates will be measured and compared to the results of the inlet angle of 45 degrees.

**References and Related Publications**


Using Acoustic Sensor Data to Diagnose Multi-Stage Hydraulic Fracture Treatments

Abstract

Acoustic sensing technology has a long history in the oil and gas industry, from the early days of measuring seismic activity to determine the location of an oil and gas reserve to present day technology, such as Distributed Acoustic Sensing (DAS) using fiber optic passive sensors. The new DAS technology is capable of measuring the acoustic signature in the near wellbore fracture region and analyzing the measured data to predict important downhole parameters such as active producing zone, flow rate, etc. However, DAS is still a new technology in the early stages, partially due to the complexity of the acoustic behavior phenomenal in a downhole environment.

This project is organized into mathematical modeling and experimental study parts. In the experimental section, research will show how different downhole parameters change the acoustic behavior measured in our experimental setup. In the mathematical modeling section, attempts will be made to verify the experimental results and develop a mathematical model to relate downhole parameters and correlating acoustic behavior.

Objectives

» Determine the impact of various fracture, fluid, and perforation parameters on acoustic signatures for fracture flow

» Establish correlations and mathematical models experimentally and theoretically to interpret flow condition from acoustic signals

» Diagnose the success of hydraulic fracturing from downhole DAS measurements

Approach

This project studies how various downhole parameters change the acoustic signal in a controlled laboratory setup. Parallel to the experimental study, the research will work on developing a mathematical model to relate downhole parameter and acoustic signal change. The project begins with modeling flow through perforation and then moves into the flow through fracture part. As the project progresses, it compares the modeling and experimental results for verification purposes.

Accomplishments

The experimental study conducted on the vertical fracture cell setup found interesting relations between the parameter of interest and acoustic behavior change, as presented in our SPE ATCE presentation on October 27, 2014. All of the experiments were conducted on the setup shown in Fig. 1.

Significance

The experimental results allowed an improved understanding on the relation between parameter of interest and acoustic behavior change. The research obtained a number of data sets that can be used for future analysis.

Future Work

» Develop mathematical modeling to verify the experimental results.

» Conduct additional experiments on the Vertical Fracture Cell Experimental Setup.

We will convert the current vertical setup to a horizontal setup as shown in Fig. 2.
References and Related Publications

Fig. 2–Horizontal Fracture Cell Experimental Setup
Novel Artificial Lift Methods to Increase Reserves in Shale and Tight Sand Gas Reservoirs

Abstract
The purpose of the proposed research is to develop novel approaches to artificial lift of vertical, horizontal and inclined wells in tight sand and shale gas reservoirs. This phase of the project starts by looking at multiphase flow models in vertical wells in association to the pump placement in wells with liquid loading.

Objectives
The objectives for this phase of the research include literature survey and familiarization with some of the work done on transport models in vertical and deviated wellbores.

Approach
Research will start with a simple model of a vertical well and determine the ideal location for the placement of an electric submersible pump (ESP). Using models for multiphase transport, work will be performed on this aspect in the coming months. Once vertical wells can be dealt with more confidently, research will focus on deviated and horizontal wells.

Accomplishments
The project started two months ago and the work that has been done to date includes literature survey and obtaining familiarity with problems and different issues with the artificial lift in question.

Significance
The inability to efficiently lift water from unconventional gas wells is a major constraint on ultimate recovery from such wells. When it becomes impossible to lift the water from a producing well, the well must be abandoned, even though there may be considerable gas reserves remaining in place. Artificial lift provides one of the solutions in such a case.

Future Work
The project just started; much work needs to be done in this area. The next few steps involve studying the issues related to artificial lift systems, reviewing the different transport mechanisms in deviated and horizontal wells, and investigating the flow equations in shale reservoirs.

References and Related Publications


Yoshioka, K., Zhu, D., Hill, A.D. and Lake, L.W. 2007. A new inversion method to inter-
pret flow profiles from distributed temperature and pressure measurements in horizontal 
wells. Paper SPE 109749 presented at SPE the Annual Technical Conference and Exhibi-
tion held in Anaheim, California, USA., 11–14 November.
Diagnosis of Multiple Fracture Stimulation in Horizontal Wells by Downhole Temperature Measurement for Unconventional Oil and Gas Wells

Abstract
Fracture diagnosis can be done with several methods, including direct and indirect measurements and temperature data. During the injection period for hydraulic fracture treatment, cold fluids are injected into a shale gas formation which results in cooling of the formation around the fracture and the wellbore. Subsequently, the near fracture region warms up due to heat flux from the external reservoir rock during the shut-in period. In this study, energy and mass conservation equations are developed which are then used to calculate the fracture propagation and temperature distribution for a three dimensional penny-shaped fracture and also for the surrounding formation. Flow back during the shut-in period will also be considered.

Objectives
- Develop a fracture model to predict the fracture growth and fluid distribution for a single penny-shaped fracture in a horizontal well during injection using a mass balance approach.
- Predict the fluid temperature profile inside the fracture at any time during treatment.
- Estimate the warm up effect during the shut-in period and generate a flowback model based on the forward model.

Approach
The fluid temperature profile inside the penny-shaped fracture was obtained by solving the fracture temperature model. A new consideration for updating the temperature during the next step is generated in the temperature model.

A case study regarding leakoff effect has been considered, based on the previously developed temperature model for the penny-shaped fracture. The model runs different leakoff coefficients in order to study the leakoff effect during injection for two different cases. One case holds the total injection volume steady and compares temperature distribution inside the hydraulic fracture. The other case holds the same fracture radius and compares the temperature profile.

Accomplishments
While reviewing literature for temperature modeling, it is noted there has been a lot work done for profiling the wellbore flow model by interpreting downhole pressure and temperature data. However, the use of temperature data is limited for qualitative interpretation at the present time. It is especially significant that no literature is available on interpreting the temperature data inside a penny-shaped fracture and the surrounding formation in a horizontal well during hydraulic fracture treatment. In other words, there is no fully developed numerical thermal model that can be applied to penny-shaped fractures and the surrounding formation for horizontal wells. In this study, a fracture model was developed to predict the fracture growth and fluid distribution for a single penny-shaped fracture in a horizontal well during injection using a mass balance approach. Also, two separate models were derived for modeling the heat transfer in the fracture and the surrounding formation in order to obtain a temperature profile.
models are bound by the boundary conditions and are solved by coupling each other. This allows us to obtain the temperature distribution at any location and at any time inside the fracture or the surrounding formation. Eliminating the injection term, and calculating far from the fracture surrounding the formation of these models, can give us the warm back arriving temperature at the wellbore, and thus the history matching of the data transformation services (DTS) data along the wellbore can eventually be fulfilled.

**Future Work**

Comparison of temperature profile inside the fracture for both a penny-shaped fracture model and a penny-shaped plus linear fracture model will be estimated.

» The numerical model of temperature distribution inside the fracture and surrounding formation will be generated. The temperature profile will also be updated in the surrounding formation for a penny-shaped fracture considering the temperature at the tip for next time step corresponding to the fracture temperature model.

» A finite conductivity fracture may be considered for streamline method application to trace the pressure and velocity change for point source flow condition.

» More sensitivity studies will be considered. The model will be improved by considering inconstant reservoir properties.

**References and Related Publications**


(continued on next page)


Investigation of Fracture Fluid Performance in Oil Shale with Surfactant Additives by X-Ray Tomography Methods

Abstract
Contact angle and interfacial tension (IFT) of fluids determine rock wettability. Surfactants can aid in changing the wettability of the rock to make it more water wet and allow effective imbibition of fracture fluid into the rock matrix and the consequent expulsion of oil, leading to improved estimated ultimate recovery (EUR). Contact angles and IFTs of fluids can be robustly studied using the sessile drop method. Measuring contact angles can provide information about dynamic processes which occur during hydraulic fracturing of shale reservoirs. Computed tomography (CT) can be used to study the penetration magnitude of the fracture fluid imbibition during hydraulic fracturing. Fracture fluid with various surfactant compositions and concentrations will be pumped through this core and the core will be CT scanned throughout the experiment at different durations of time. The oil recovery at the end of each experiment for every surfactant will be measured to calculate recovery efficiency and used to compare the performance of the surfactants in improving EUR.

Objectives
» Evaluate and compare surfactants that can alter wettability in oil shale.
» Measure contact angle and IFT to determine rock wettability and efficiency of fracture fluid imbibition.
» Study the penetration magnitude of the fluids and the amount of produced oil from the shale cores using CT scan methods at reservoir conditions.
» Evaluate the interaction between fracture fluids and artificially fractured shale cores by measuring oil expulsion and comparing CT response and oil saturation before and after injection.

Approach
Our study proposes to evaluate and compare the ability of different classes of surfactants to improve efficiency of water imbibition into the matrix and improve EUR by analyzing contact angles, IFT and studying imbibition penetration using the CT scanner. The workflow of the project is as follows:

» Evaluate and compare the ability of different groups of surfactants to alter wettability and improve efficiency of water imbibition in oil shale cores by conducting contact angle and IFT measurement experiments at reservoir conditions.
» Use CT to quantify depth of fracture fluid imbibition, penetration, and improvement in EUR in artificially fractured shale cores by measuring oil expulsion and comparing CT response and oil saturation before and after injection of fracture fluid.
» Identify surfactants which provide optimum performance for use in fracture fluid stimulation treatments in shale oil reservoirs.

Accomplishments
Surfactant Stability Test
Six surfactants (one Anionic, two nonionic, two anionic + nonionic) at 2gpt, three complex nano emulsions (CNEs) at 2gpt, silica nanoparticles at 1%wt and mixture of silica nano particles + nonionic surfactant at 1%wt +1gpt were evaluated in contact with dead oil from the ULR reservoir in 3% and 10%wt brines. The experiment was performed at reservoir temperature (165°F) in an environmental chamber for three weeks. The results (continued on next page)
showed that all surfactants and CNEs in 10%wt brine (Fig. 1) have cleared aqueous phase than the same one at 3%wt brine (Fig. 2). The increase in salinity makes surfactants to go to the interphase instead of staying in the aqueous phase. This also helps to reduce IFT between water and oil. This observation was corroborated by the fact that most anionic surfactants were unstable at 3%wt and even more at 10%wt brine without oil, but after the oil was added, they turned stable as showed in Figs. 1 and 2.

Regarding the solutions that have nanoparticles and nanoparticles + nonionic surfactants (the far two right test tubes in Fig. 1 and Fig. 2), they were not stable at any point during the experiments. Silica nanoparticles are very sensible to salinity making the solution unstable. Currently, we are evaluating the effect of salinity in change of IFT. Preliminary result showed us that IFT decreases as salinity increases in surfactant solutions. This is due to the fact that surfactants monomers are in the interphase lowering the IFT rather than the aqueous phase to avoid competing with the salts for the solubilization in water.

**Contact angle experiments**

Contact angle experiments were performed using side shale cores, and five different surfactants, one anionic, two nonionic, one anionic+nonionic and one complex nano emulsion (CNE) at reservoir temperature (165°F) with three concentrations (0.2, 1.0 and 2.0 gpt). Frac fluids contained surfactants at different concentrations and fixed concentrations of biocide and clay stabilizer. The results are shown in Fig. 3. From results it can be seen that higher surfactant concentrations can shift wettability in shale samples from intermediate to water-wet. Also, CNE showed the best performance in changing contact angle.

IFT experiments were also performed using the same surfactants at reservoir temperature (165°F) with three concentrations (0.2, 1.0 and 2.0 gpt). The results showed that IFT values decreases as surfactant concentrations increases which could improve water imbibition performance in the matrix. In addition, anionic and anionic+nonionic surfactant showed the best capability of lowering IFT than nonionic surfactants.

**Penetration Magnitude by CT Scan Methods**

A core-flooding system was designed to be combined with the CT-scanner. The integrated system enabled us to dynamically visualize the movement of the fluid as it penetrated the shale samples in real-time. The experimental instrument setup which consists of five
components: the injection system, the core flood cell, CT scanner, the production system, and the data acquisition system. This system is currently in use and the results will be presented in the next report.

**Significance**
The findings of this research project have indicated that surfactants can change wettability in shale cores from intermediate wet to water wet as well as decrease interfacial tensions with oil. Surfactant stability is reached in the presence on oil lowering IFT as salinity increases, but without the oil surfactant stability is affected by salinity increase.

**Future Work**
We will perform spontaneous imbibition experiments using CT scanning to evaluate different surfactants and CNEs.

We will study core flooding in oil shale with x-ray CT by scanning oil-saturated core plugs from producing wells; scanning anionic, non-ionic surfactants; and representing hydraulic fracture media by glass beads inside an aluminum core holder at reservoir conditions.

**References and Related Publications**
**Quantifying Vertical Heterogeneity in Carbonate Formations using Well Logs for Improving Prediction of Acid Fracturing**

**Abstract**

Acid etching, as the consequence of heterogeneous distribution of petrophysical and compositional properties, results in the conductivity of acid fractures in carbonate reservoirs. Reliable characterization of small-scale formation spatial heterogeneity using geostatistical analysis (i.e., variogram analysis) can significantly improve prediction of acid fracture productivity (Mou et al. 2011; Deng et al. 2011; Oeth et al. 2013). However, carbonate formations are complex and therefore the assessment of their petrophysical, compositional and elastic properties is challenging. Rock typing based on conventional well logs has been suggested in the literature to improve characterization of formation spatial heterogeneity in carbonates. Furthermore, a reliable rock classification based on petrophysical and compositional properties can be used to enhance the selection of fracture candidate zones.

We will apply an analysis of different pore types by quantitatively evaluating Saturation-Dependent Mercury Injection Capillary Pressure (MICP) measurements in a carbonate formation. We will then use the identified pore types and well-log-based estimates of porosity, and the volumetric concentrations of minerals for rock classification. The assessment of permeability is enhanced by applying rock classification in the carbonate formation understudy.

**Objectives**

The main objectives of this work are (a) depth-by-depth assessment of pore types using MICP data in the core domain and in the well-log domain, (b) rock classification based on the identified pore types and well-log-based estimates of petrophysical properties and volumetric concentrations of minerals in a challenging carbonate formation, and (c) assessment of permeability for enhanced prediction of acid fracture productivity.

**Approach**

We will apply a multi-modal Gaussian function to the model and fit the MICP measurements available at specific depths. We will then use a k-means clustering technique to identify pore types using the fitting parameters obtained from MICP Gaussian functions. We will use the k-Nearest Neighbors (KNN) algorithm to populate the pore types in well-log scale. Multi-mineral interpretation based on conventional well logs will be conducted to estimate porosity and volumetric concentrations of minerals. Finally, we will apply an unsupervised neural network to classify rock types based on depth-by-depth estimates of petrophysical and compositional as well as the identified pore types. Permeability will be estimated based on the core-derived porosity-permeability correlation in each rock class.

**Accomplishments**

We successfully applied the proposed technique in a carbonate formation, Kelly-Snyder oil field. Fig. 1 is a typical plot of the fitted Gaussian function through the MICP core data. Eq.1 is the Gaussian function. Fig. 2 shows the results for the well-log interpretation, rock classification, and permeability assessment. The petrophysical rock classification is in a good agreement with the identified core-derived rock classes. Also, well-log-based estimates of permeability are improved when compared to a conventional permeability assessment technique.

\[
y = 4.7814\exp\left(-\frac{(x + 0.2473)^2}{0.2225}\right) + 5.7125\exp\left(-\frac{(x - 0.4317)^2}{1.4724}\right)
\]  

(1)
Significance
We enhanced the assessment of permeability in a carbonate formation by implementing our proposed rock classification method. The contributions of this work include (a) application of a quantitative approach for pore typing using MICP data and (b) incorporation of the identified pore types in petrophysical rock classification. The integrated rock classification based on petrophysical and compositional classifications can be used to enhance production in carbonate formations.

Future Work
Our future plans include conducting pore-scale simulation of electrical current to investigate the impact of different pore structures detected from micro-CT scan images of carbonate rocks on resistivity well logs. The outcome of this work can improve rock classification and characterization of formation heterogeneity in carbonate formations.

References and Related Publications


Fig. 2–Field Example - Kelly-Snyder oil field: Conventional well logs and the estimated petrophysical/compositional properties. Tracks from left to right include, Track 1: depth; Tracks 2-6: tension, caliper, GR, neutron porosity (in water-filled limestone units), bulk density, and apparent resistivity logs; Track 7: estimates of volumetric concentrations of calcite, quartz and shale; Tracks 8-9: total porosity, overlaid with the corresponding core measurements, and water saturation; Track 10: rock classes; Track 11: permeability estimates after rock classification, overlaid with core measurements of permeability.
Project 2.5.25  
Analysis of Fracturing Behavior of Ultra-Tight Geologic Media Across Spatial Scales: From Fundamental Studies to Field Applications

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Multi-Scale Studies of Fracture Initiation and Propagation

Abstract  
Hydrofracturing (HF) is an industry-accepted method of making ultra-low-permeability (ULP) resources economically profitable. A significant amount of HF is unsuccessful. One of the reasons is an inadequate understanding of the phenomena of fracture initiation and propagation, which is currently limited to parameters such as the initial distribution of maximum and minimum horizontal stresses and basic geomechanical properties such as the Poisson’s ratio, the Young’s and shear moduli of elasticity, etc.

Experimental investigation will involve the visualization of fractured surfaces and of planes at angles to them from the nm- to the cm-scale, the development of statistical models associating fracture trajectory with the spatial distribution and mechanical strength of nano- to micro-fractures and inclusions, as well as with the orientation of beds and stratification to the initial stress distribution.

The statistical models will be used to develop mathematical models of fracture initiation and propagation accounting for these factors, and will be tested in laboratory-scale studies involving representative samples of ULP media.

Objectives  
Develop statistical/mathematical models to describe the initiation and propagation of HF fractures.

Incorporate fundamental models into field-scale simulators of hydraulic fracturing.

The hypothesis is that the trajectory of propagating fractures is not a purely random process, but is controlled by both macro-factors (such as the initial stress distribution and the orientation of the well, the bedding, and the stratification) and by the distribution of micro-features, such as the aforementioned fractures and inclusions, in relation to the macro-factors and the characteristics of the stimulation process.

Approach  
Samples of ULB formations will be studied at various scales (from nano-scale visual observations of fractured surfaces to laboratory-scale investigations to simulations from lab- to field-scale) before and after the application of fracturing with intent of characterizing the nano- to micro-characteristics of the rock (i.e., mainly fractures and inclusions of significantly different mechanical strength from the main body of the rock).

Distribution of the micro-features on a fracture surface and on planes parallel and perpendicular to it after proper fracking of core will be studied by using:

Synchrotron X-ray Micro-computer tomography (CT)

Scanning Electron Microscopy (SEM) for the observation of select surfaces

Focused Ion Beam milling Scanning Electron Microscopy (FIB-SEM), which is capable of providing volume data with a resolution as low as 0.5 nm

Accomplishments  
Pilot images of Wolfcamp shale similar to those presented by Hu et al. (2014) were received from CT-scanning (see Fig. 1). Bedding plate orientation was easily observed for further research.
**Significance**

For Eagle Ford shale, Landry et al. (2014), and previously Gale et al. (2007) for Barnett shale, proposed to interpret fractures by using SEM images and separate partially cemented natural fractures from those generated by core exhumation, dry-out and handling.

A recent study of Hu et al. (2014) indicated the strong effect of natural fracture orientation on the fracture propagation pattern. Young’s modulus and Poisson’s ratio are also affected by natural fracture orientation.

Based on literature review, it is possible to repeat proposed measuring procedures by Hu et al. (2014) on cores other than from the Eagle Ford formation and compare results.

**Future Work**

Future experimental work will be focused on scanning microfractured formations and analyzing parameters of natural and core damage related fractures in both parallel and perpendicular direction to induced fracture with the following equipment:

- Micro-CT - recent papers showed a need of micro-CT to identify small natural fractures.
- SEM scanning - essential to distinguish natural fractures from those generated because of core damage and to get statistics of small fractures distribution.
- FIB-SEM - important for getting volume data with a resolution of 0.5 nm.

**References and Related Publications**


Evaluation of Strategies for Enhancing Production of Low-Viscosity Liquids from Tight/Shale Reservoirs

Abstract

Production of low-viscosity liquids (including condensates) from tight reservoirs, such as shales, is severely restricted by the ultra low-permeability of such formations, limiting production to a very small fraction of the liquids-in-place. We propose to evaluate by means of numerical simulation a wide range of possible strategies to enhance low-viscosity liquids from production from such reservoirs.

Objectives

To evaluate a wide range of possible strategies to enhance low-viscosity liquids production from tight/shale reservoirs by means of numerical simulation

Approach

We start from the pore scale fundamental research on the pore structure and fluids and shale properties. We then move to the numerical approach of mesoscale and field scale simulation with single through multiphase flow among shale matrices and fractures, especially focusing on the effect of interactions between fracture and flow dynamics on the liquid production and its enhancement

Accomplishments

General characteristics of liquid rich shale reservoirs:

- Hydrocarbon source rock represented as organic rich matter with calcite/quartz clay-rich rocks
- Fluid source and storage mainly within the organic-rich material
- Conduit for flow within the organic-poor portion of the matrix and the natural fracture network
- Heterogeneity and anisotropy in rock properties and variability in fluid properties
- Wettability varying from strongly oil-wet to mixed-wet, contributing to oil and water imbibition in different layers
- Different levels of total organic carbon and degrees of maturity in a wide range of oil API gravity (10°-35°) and gas oil ratio (300-10,000 scf/stb)
- Low matrix permeability and nano scale pore throat size near the molecular size of the large liquid component distribution (1-20 nm)
- Unconventional fluid flow behavior: Knudsen flow and Non-darcy flow in the fracture
- Drastic change of micro fractures-matrix permeability system due to higher stress conditions during depletion

In-situ fluid pressure/volume/temperature properties, especially if production is occurring at or in the critical fluid phase:

- Managing the condensate banking, which occurs when the reservoir pressure drops below the dew point pressure and the liquid reaches its critical saturation point.
- The fluid mobility control
- The impact of an extra phase on the relative reservoir permeability

Key factors to place effective and conductive stimulations related to the rock properties

- The local stress state (e.g., magnitude and anisotropy)
- The rock physics model (brittleness vs. rock deformation)
- Some geomechanical rock parameters with the mechanical earth model
These parameters/models impact:

» Vertical vs. horizontal hydraulic fracture development
» Connected network of weak-planes vs. localized/disconnected features
» Efficient zonal diversion during stimulation, compaction
» The stress sensitivity of the reservoir permeability

**Significance**
Research, on not only the essential fluid parameters but also on the liquid rich shale formations and rock properties in a wide range, is intended to figure out and simulate the critical multiphase flow dynamics in shale formation, ultimately leading to the enhanced liquid recovery mechanism.

**Future Work**
One of the greatest challenges is assessing the amount and character of fracture permeability in the stimulated shale reservoir. Natural fractures are addressed with structural mapping, and geomechanical modeling is critical to effective hydraulic fracture stimulation. Rock geomechanical properties play a key role in unconventional reservoir appraisal and development because they influence the dimension and configuration of the stimulated rock volume, as well as production regime and sustainability.

Future work would be geomechanical characterization from the poroelastic/thermoelastic through the viscoelastic and plastic properties of the rock and its coupled flow simulation determining the in-situ stress regime, stress magnitude, rock mechanical properties and pore pressure functioning for or against permeability, flow and production regime.

**References and Related Publications**


(continued on next page)


Beyond Dual-Porosity Modeling for the Simulation of Complex Flow Mechanisms in Shale Reservoirs

Abstract
Shale reservoirs have complex porosity types, organic matter, inorganic matter, and natural/hydraulic fractures. The distinctive and complicated storage/transport characteristics in these porosity systems require special and careful attention when we simulate multiphase flow in shale reservoirs. The mechanisms of the molecule/wall interactions, the slippage of the gas phase, and the multicomponent desorption have been investigated in order to be incorporated into our multiphase shale fluid flow simulator in the future.

Objectives
Investigate mechanisms of molecule/wall interactions, slippage of the gas phase, multicomponent desorption, and the influences of these three mechanisms in shale fluid flow. Propose the general governing equations considering these effects.

Approach
Different flow regimes (one important defining parameter is the Knudsen number) need different flow theories and equations in order to be characterized. The classical flow equations and continuum theory break down when the pore size becomes nano-scale as in some organic pores of the shale reservoir. The unified physics-based model proposed by Beskok and Karniadakis (1999), which considers a second-order slip boundary condition and a correction term expressed as rarefaction coefficient, has been selected to describe the gas phase flow in the shale reservoir. The modifications proposed by Civan (2010) have been accepted to account for the non-tube irregular shape of pores in hydrocarbon reservoirs with a tortuous flow path. The molecule/wall interactions will be incorporated into our simulation through the concept of apparent permeability, which can be given by the models mentioned above (Beskok and Karniadakis 1999; Civan 2010).

Adsorption is considered to occur in the organic pores of the shale reservoirs, and the commonly used empirical models like the Langmuir isotherm are practically accurate when used in the shale reservoir. The multi-component Langmuir equation, first developed by Butler and Ockrent (1930), is used to describe the multi-component adsorption effect in our investigation.

Accomplishments
The mechanisms of molecule/wall interactions, slippage of the gas phase, multicomponent desorption, and the influences of these mechanisms in shale fluid flow have been investigated. The unified physics-based model (Beskok and Karniadakis 1999; Civan 2010) and the multi-component Langmuir equation (Butler and Ockrent 1930) have been selected to describe the molecule/wall interaction and the multicomponent desorption, respectively.

The general governing equations considering the molecule/wall interactions and slippage of the gas phase, and the multicomponent desorption have been proposed, shown in Eq. 1 through Eq. 3.

\[ \nabla \left( X_g^s \rho_o \frac{K_{apparent} K_{rG}}{\mu_o} (\nabla P_o + \rho_o \hat{g} \nabla z) + X_g^s \rho_o \frac{K_{rG}}{\mu_o} (\nabla P_o + \rho_o \hat{g} \nabla z) \right) = \frac{\partial(X_g^s \rho_o S_o \phi + X_g^s \rho_o S_o \phi)}{\partial t} - \frac{\partial(q_{\text{gas adsorption}} (1 - \phi))}{\partial t}, \]

(continued on next page)
Significance
The molecule/wall interactions, the slippage of the gas phase, and the multicomponent desorption have important influences in shale fluid flow. Understanding these mechanisms and their influences will increase the accuracy of multiphase shale fluid flow simulation and improve the hydrocarbon recovery efficiency overall.

Future Work
The multiphase shale fluid flow simulator based on the governing equations Eq. 1 through Eq. 3 will be developed, and the corresponding parameter sensitivity analysis will be conducted.

References


Molecular Simulation of Fluid Phase Behavior in Shale Systems

Abstract
Phase behavior in shale remains a challenging problem in the petroleum industry due to many complexities. One complexity is due to strong surface-fluid interactions in shale nano-scale pores. These interactions can lead to heterogeneous distribution of molecules. Conventional bulk-phase thermodynamics cannot describe this heterogeneous molecular distribution, yet the majority of current models for phase behavior in shale are based on bulk-phase thermodynamics.

In this project, we will use molecular simulation methods to accurately model the effect of solid-fluid and fluid-fluid interactions in shale. We modeled pressure/volume/temperature (PVT) properties for pure hydrocarbons with and without the confinement effect and will extend the simulations to their mixtures in the next period.

Objectives
The main outcome of this project will be a software package (mPVT) to predict phase behavior of petroleum fluids in shale rocks. The inputs of the software will be pressure, temperature, fluid composition, pore size distribution, pore-wall material and bulk PVT properties of a petroleum fluid. The output will be corresponding confined PVT properties in the shale systems.

Approach
In this project, we propose to use molecular simulation to calculate the phase behavior of petroleum fluids for the shale reservoirs. We will use the Gibbs Ensemble Monte Carlo (GEMC) simulation technique for the calculation of phase coexistence at conditions far from critical point. We will use the Grand Canonical Monte Carlo (GCMC) simulation technique to accurately predict the phase behavior of petroleum fluids close to the critical point. We will use the canonical simulation technique to study the boundary effect on the interface. We plan to include the surface charge of pore structure and partial charge of molecules such as CO₂. In all steps of the project, we will compare the molecular simulation results with experimental data (if available) and predictions of the most popular equations of state.

Accomplishments
In this period, we performed phase-equilibrium calculations with the boundary effect for pure systems by GCMC histogram reweighting technique. Based on the prior information from the conventional techniques, the phase diagram can be determined at lower temperatures, as the initial guess for critical point. With mixed-field finite-size scaling analysis, the critical point can be located, as shown in Fig. 1, for the ordering operator distribution of pure ethane in the graphite slip pore (4nm). The phase diagram near the critical point can be calculated by the GCMC histogram reweighting method. Combined
with the trial and error results, the phase diagram is determined for the whole temperature range, as shown in Fig. 2, for the pure ethane in the nano-pore.

Moreover, canonical ensemble simulation is used to generate the two phase coexistence in one box, as shown in Fig. 3, for ethane in 5nm split pore with graphite boundary. The density results from canonical ensemble simulation are not accurate, but it can provide a physical understanding of the interface and be used to double check the results from histogram reweighting.

**Future Work**

In the next period, we will continue the work on properties of phase coexistence in shale reservoirs for hydrocarbon pure systems and mixtures from different methods. Then we will include the boundary charge and component polarity.

![Fig. 3–Snapshot of pure ethane (red) in graphite (blue) slip pore (5nm)](image-url)
Efficient Multiscale Simulation in Shale Reservoirs

Abstract
Unconventional reservoirs, such as shale gas, represent an enormous and mostly untapped source of domestic and global energy. These reservoirs have the potential to revolutionize our energy economy and provide significant economic, strategic, and environmental benefits. The flow and transport in unconventional reservoirs exhibit coupled solid/fluid interaction and transport behavior at several scales and contain uncertainties at these scales (e.g., media properties and geometrical representation). The main challenges lie in simulating this transport process accurately with high spatial resolution and low computational cost, taking into account potential non-Darcy effects during gas production. These issues can be addressed by using the Lattice Boltzmann Model (LBM) which can model a large spectrum of scales in an efficient way.

This project proposes to investigate the LBM formulation to simulate reservoirs at the field scales. The LBM will be used to accurately evaluate the transport phenomena in shales in a variety of scales incorporating the correct physical phenomena (e.g., non-Darcy effects) and will be used as a testbed for fast history matching workflows in shale productions. The primary outcome will be a fast and reliable software suite that simulates field scale unfractured and fractured reservoirs using the LBM framework. Although we anticipate that the primary task will take most of the efforts in this research, we also foresee a secondary benefit in the application of the LBM in the history matching process. This may involve parameter estimation using microseismics and other production data.

Objectives
» Investigate the basic 2-D poiseuille flow in nano-pores with a tortuous flow path and incorporate slippage conditions typically encountered in the simulation of shale reservoirs.
» Model fluid flow using 2D-LBM in micro-channels for a synthetic 2-D porous media.

Approach
Analysis was done for fluid flow in a porous media containing micro-channels, with the inclusion of slip conditions which would account for flow in the Knudsen regime where the continuum fluid flow assumption is not as accurate. This means the Navier-Stokes equation used here loses its ability to effectively predict complex flow problems involving such flow (Succi et al. 2002; Homayoon et al. 2011). A synthetic 2-D porous media system for our selected two-dimensions and nine fixed velocity scheme (D2Q9 scheme) with dimensions 80 x 190 lattice units has been defined here. The slip reflection boundary conditions we introduced were comprised of both specular and bounce-back parameters which were used to obtain the slip velocities at the boundaries. The slip factor was varied between 0 and 1 and represented no slippage (typical fluid flow) and full slippage respectively. The analytical solution obtained from the poiseuille flow was first matched with the LB velocity simulated. Porous media was then incorporated and slip conditions were then introduced. This set-up was executed using the MATLAB software.

Accomplishments
By varying the slip conditions whose regimes are defined as a function of the Knudsen number and at properly designated relaxation times, a micro-scale flow LBM simulation was done and the effect of slippage on the velocity, and hence the permeability, was observed. The results in Fig. 1 show that as the slip effect is increased by increasing the Knudsen number, there is an effective increase in the dimensionless fluid velocity which thus leads to an increase in the deduced permeability (Zhang et al. 2014) In addition, results also confirm a similar observation by Succi (2002) easily identified as a sudden rise
in the LBM velocity. This indicates that above a critical point, which lies at $0.9 < s < 0.99$ in this case, a sudden significant increase in slip motion sets in indefinitely with respect to the pre-defined system time scale.

**Significance**

This project proposes to tackle the complex process of simulating unconventional reservoirs by developing a software package within the LBM framework. If successful, we will have developed new models with a solid mathematical foundation that better represent the underlying physics on a hierarchy of scales, developed and applied state-of-the-art high performance computing techniques that address the multi-scale nature of modeled physical processes in the presence of data uncertainties, and provided integrated tools and concepts for model accurate predictions and, in turn, optimized shale gas production. Thus, it is important at this preliminary stage to understand the multiphase model to be selected and its stability if we intend to apply LBM framework from pore scale to field scale solution.

**Future Work**

» Understanding the 3D-LBM fluid flow for more accurate shale pore representation.

» Incorporating reservoir core micro-CT and network images into this 3-D LBM frameworks and exploring fluid flow characteristics

**References and Related Publications**


Efficient Multiscale Simulation in Shale Reservoirs

Abstract
The Lattice Boltzmann Method (LBM) was initially designed as a numerical solution for problems of gas and liquid hydrodynamics (Viggen 2009). Later it was modified for calculations of flow in porous media, per Brown et al. (2014). The main advantage of LBM high efficiency in parallel computations: speed of calculation is almost proportional to number of processes (Saenger 2002). That is the motivation for further development of this method for applications in reservoir simulations.

Objectives
Develop tools for simulation operation of the well with hydraulic fracture by means of the Lattice Boltzmann Method.

Approach
The main idea is to simulate operation of the hydraulic well by application of appropriate boundary conditions at the nodes near the well and the fractures similar to those found in Lallemant and Luo (2003). In order to determine such boundary conditions, it seems reasonable to start with a fracture with infinite permeability and then make corrections to account for the permeability distribution in the region around the fracture.

Accomplishments
Boundary conditions for 2 dimensional horizontal flow to a well with a fracture were proposed. This method was verified in the case of a steady-state flow in a homogenous rectangular reservoir. Results of the numerical calculation were compared with a semi-analytical solution. The method qualitatively reproduces pressure distribution around the fracture (Fig. 1), but it doesn’t match well with the semi-analytical solution (Fig. 2). The deviation is not severe but certain improvement has to be done.

Significance
Wells with hydraulic fractures are very common in the petroleum engineering practice. It is the reason why each tool for simulation that can predict the performance of such wells is greatly desired.

Future Work
There are several directions for future work including the improvement of the accuracy of the method, the application of unstructured grids and grids refinement methods, the addition of a third dimension, and the application of dimension and scale reduction techniques to take into account finite permeability of the fracture.

References and Related Publications


Nanopore Confinement Effects on Multi-Component Phase Behavior in Wet-Gas Shale Reservoir System

Abstract
Following our studies in phase transitions and behavior of multicomponent fluid in nanopores, we found the role of light components in these fluids to be important. We saw more dramatic shifts in the phase diagrams in confined binary and ternary hydrocarbon mixtures with high percentages of light components such as methane. From these phase diagrams, we extracted critical temperatures and pressures of these mixtures and compared them to those obtained from the Peng-Robinson Equation of State and also the Piper et al. correlation. In addition, we also studied whether the simple Kay’s rule would apply to the confined mixture (i.e., if the molar-averaged shifted single component critical parameters constituting the mixture would yield the mixture’s critical parameters). This was found to be negative, therefore we could not find a direct correlation between mixture critical parameters and those of its constituent single components. In conclusion, the differences in values obtained from these methods and our molecular simulations show the necessity of developing new and more appropriate correlations for the phase behavior of fluid in confinement.

Objectives
In this work, with the help of molecular simulations, we focus on multicomponent fluids with various compositions and study their phase behavior to plot their phase diagrams and find their critical parameters in each condition. The idea is to develop a mixing rule for these mixtures in terms of composition, temperature, pressure and pore size.

Approach
These simulations are carried out in the NPT-Gibbs ensemble of Monte Carlo, in which two computational boxes are set up: box 1 contains bulk gas and box 2 is the slitpore (i.e., the box is restricted by two parallel graphite walls). Simulations are set to run until they reach equilibrium. The total number of molecules (N), system pressure (P) and the temperature (T) are kept fixed throughout the simulation. In such mixtures, the heavy component (which in this case is n-butane) tends to settle in the area right by the pore walls, allowing the lighter component (methane) to occupy the central area and also dominate box 1. Starting from a certain temperature T, we found, with various runs, the pressures at which the transition to two-phase vapor-liquid and to liquid occurs, and we recorded this on the phase diagram. We continued the runs at increasingly higher temperatures until we reached the pressure where we no longer saw two-phase vapor-liquid transition. We studied binary mixtures of C1-C2, C1-nC4 and C1-nC8 in two systems of 50% (molar) C1 and 90% (molar) C1.

Accomplishments
Fluid composition in mixtures plays an important role due to its phase behavior in confinement. The confining walls apply different forces on different molecules causing a composition profile inside the pore; lighter components occupy the more central spaces of the pore. From chemistry, we know that light hydrocarbons tend to have lower bubble/dew-points. In our simulations, we found the shift in phase diagrams in all 90% (molar) C1 binary mixtures to be much more severe than the 50% (molar) C1 binary mixtures. In other words, the phase diagrams were shifted much lower and closer to the C1 phase diagrams. (See Fig. 1)
Fig. 2–Phase diagrams of ternary mixtures when mixture is in bulk (filled circles) and when confined to 4nm pore (empty circles).

Table 1–Comparison of critical parameter of a ternary mixture obtained from four different methods. Single-component parameters are from Singh et al. 2009.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Bulk State</th>
<th>4nm Confinement</th>
<th>10% C₁ - 50% nC₄ - 40% nC₈ Mixture</th>
</tr>
</thead>
<tbody>
<tr>
<td>C₉</td>
<td>190</td>
<td>425</td>
<td>568</td>
</tr>
<tr>
<td>nC₄</td>
<td>181</td>
<td>402</td>
<td>533</td>
</tr>
<tr>
<td>nC₈</td>
<td>465</td>
<td>660</td>
<td>465</td>
</tr>
</tbody>
</table>

Significance

In this study we obtained phase diagrams of mixtures using our methodology in the NPT-Gibbs ensemble Monte Carlo. We found that the trend in the Temperature-Density phase diagrams of confined fluid follows that of its bulk state: first uphill, reach critical point, and fall downhill. The various cases we studied (binary and ternary) gave us an idea of the major influence of the lighter components on mixture phase diagrams in confinement. Also, the correlations that are currently used in reservoir simulators, even with “shifted” (corrected for pore size) single component critical parameters, were found to be significantly different from results obtained from our molecular simulations on the entire mixture in confinement.

Future Work

We will continue to work on generating correct phase diagrams of confined multicomponent gases leading to critical parameters and finding new correlations to fit the data.

References and Related Publications


Critical Liquid Saturation and Relative Permeability Curves in Carbon Nanotubes using NEMD

Abstract
In order to build a reservoir flow model, the new petrophysics affected by micro scale confinement and sorption effect is to be extracted from the shale layers. One important area that requires rigorous scientific research is multi-phase transport in matrix, since it is the matrix that supplies the fluids in linear-fracture and bilinear flows. Despite the fact that multi-phase flow experiments of shale matrix are time-consuming and challenging, today’s high performance computing technology enables the simulation of transport in capillaries up to 0.5 micro meters on the molecular level. This range covers a large fraction of the matrix pores. In the second stage of the work, we applied “external force non-equilibrium molecular dynamics” method (EF-NEMD) to simulate the fluid flow in a homogeneous capillary with an external force applied, and got velocity profiles and calculated transport coefficients.

Objectives
Our ultimate goal is to quantify changes in interfacial tension (IFT) as a function of the capillary radius and liquid saturation by using lean gases (methane, CO₂, N₂) and common surfactants (SDS, C12E6) to investigate the classical enhanced oil recovery concepts of minimum miscibility, IFT reduction, micellization, and critical micelle concentration (CMC) under confinement. Also, the multi-component flow behavior will be investigated by varying liquid saturation, using molecular dynamics simulations to determine the critical saturation and relative permeability as well as pore pressure and pressure gradient effects.

Approach
The Dual Control Volume Grand Canonical Molecular Dynamics (DCV-GCMD) method is an alternative method except for EF-NEMD method to investigate the flow in capillaries. Similarly, it uses an single wall carbon nanotube charged with CH₄ using Grand Canonical Monte Carlo (GCMC) simulation under selected pressures and pressure gradients. Although there exist simulation packages which can perform both MC and MD simulations, there does exist certain limitations to perform DCV-GCMD simulation. For example, the current stable release of LAMMPS is able to perform DCV-GCMD simulation but with some restrictions below:

» The GCMC part cannot run in a parallel well, which makes the simulation for a large system hard to perform.
» The MC simulation may run out of molecule IDs for long simulations, whereas long simulations are needed to study the flow profile across the capillary.
» The ability of simulating multi-atomic molecules for MC is newly added and not stable, so it may be problematic to simulate multi component DCV-GCMD.

Due to the above restrictions, a significant compromise has to be made to perform the study of DCV-GCMD with the current LAMMPS release. One solution is to make our own modifications to the specific modules of the LAMMPS package.

We have derived an expression to correlate the driving forces of homogeneous NEMD methods and inhomogeneous NEMD methods:

\[ v_{\text{streaming, DCV-GCMD}} = \frac{k_B T}{ma} \frac{\partial f}{\partial x} \frac{1}{\tau f} v_{\text{streaming, EF-NEMD}} \]

(continued on next page)
Assuming the flux of the two methods are the same, we have
\[
\frac{k_B T}{ma} \left( \frac{\partial f}{\partial x} \right) \frac{1}{\tau} = 1, \quad \text{or} \quad \frac{k_B T}{ma} \left( \frac{\Delta p}{\Delta x} \right) \frac{1}{\tau} = 1
\]
which correlates pressure gradient in inhomogeneous methods and external force in homogeneous methods.

**Accomplishments**

LAMMPS is a MD simulator mostly written in C++ and python. Its basic structure can be seen in Fig. 1.

To fully functionalize DCV-GCMD, most modifications should be made to its MC codes. In LAMMPS code, “fix_gcmc.h”, “fix_gcmc.cpp” are the core files for GCMC simulation in src/MC directory. Other files in the same directory, “fix_bond_break”, “fix_bond_create”, “fix_bond_swap”, “pair_dsme”, are also interrelated.

Through research, we gained an understanding of the detailed structure of MC code of LAMMPS, key classes and modules related to it, and proper method to customize it. Along the process, necessary communications with LAMMPS developers and users were required to guide the customization works. However, due to the complexity of the source code, satisfactory modifications have not been achieved.

**Significance**

Through the current efforts and further implementations of this research, modified LAMMPS code and a simulation module of DCV-GCMD can be used. This enables parallel simulation for multi-atom molecules and multi component simulations.

**Future Work**

» Finish modifications to LAMMPS code and compare the results to the new release of LAMMPS to test the validity of our own modifications.

» Compare DCV-GCMD results with EF-NEMD results.

» Extend the investigation to multicomponent fluid systems to study multi-phase transport.

**References and Related Publications**


Abstract
Conventional techniques for the characterization of organic-rich source rocks continue to leave many unanswered questions in unconventional reserves development. New techniques are required to better assess the viability of developing these source rocks and to reduce uncertainty associated with production. The proposed project is aimed at developing new techniques for improved evaluation of petrophysical properties and natural/induced fracture characterization using enhanced well-logging signals.

The enhanced logging signals will be generated by injecting contrast agents to the reservoir before and after fracturing. The physical properties of these particles will be designed based on the required measured response. These particles can flow in matrix fractures and will result in enhanced signals from borehole geophysical measurements such as electromagnetic, nuclear, and Nuclear Magnetic Resonance.

Joint interpretation of these enhanced borehole geophysical measurements and conventional well-log measurements (i.e., density, neutron porosity, and acoustic measurements) before and after nanoparticle injection provides reliable evaluation of in-situ petrophysical properties as well as characterization of natural/induced fractures.

Objectives
The objective of this project is to develop a new method for reservoir characterization of organic-rich source rocks which enables (a) real-time characterizing of natural fractures, (b) monitoring the geometry of induced fractures using borehole geophysical measurements, and (c) optimizing the number of required fracture stages to maximize production and to minimize environmental impacts and water requirements. In this part of the project, we investigate the impact of fractures on nuclear measurements.

Approach
To build a mathematical model looking at magnetic nanoparticles’ transport in water-gas phases in shale porous media, investigating their influence on the magnetic susceptibility of reservoir, and quantifying the effects of fractures on nuclear logs, four tasks will be performed as follows:

Task 1: Develop a mathemathic model to mimic nanoparticle transport in fractured organic rich shale reservoirs where multiple flow mechanisms are considered

Three mass balance equations for water, gas and nanoparticles are applied to solve the unknown variables by using Newton-Raphson iteration.

\[
\frac{\partial}{\partial t} \left( \sum_\beta \phi S_\beta \rho_\beta X^i_\beta \right) = \nabla \cdot \left( -\rho_w k^{w\beta} \frac{k^{w\beta}}{\mu_w} \left( \nabla P - \rho_w \Phi \right) X^i_\beta \right) + \sum Q_w
\]

\[
\frac{\partial}{\partial t} \left( \sum_\beta \phi S_\beta \rho_\beta X^i_\beta \right) = \nabla \cdot \left( -\rho_g k^{g\beta} \frac{k^{g\beta}}{\mu_g} \left( \nabla P - \rho_g \Phi \right) X^i_\beta \right) + \sum Q_g
\]

\[
\frac{\partial (C \Phi \rho_{\text{Nano}})}{\partial t} + \nabla \cdot (C \Phi \mathbf{V}) = \nabla \cdot (D_{\text{c}} \nabla C) + \sum Q_{\text{Nano}}
\]

where \( \Phi \) is the index of fluid phase (aqueous and gaseous), \( \phi \) is the porosity of porous media, \( S_\beta \) is the saturation of phase \( \beta \), \( \rho_\beta \) is the density of phase \( \beta \), \( X^i_\beta \) is the mass fraction of component \( i \) in the phase \( \beta \), \( k \) is the absolute permeability of porous media, \( k^{w\beta} \) is the relative permeability to the phase \( \beta \), \( \mu_\beta \) is the viscosity of phase \( \beta \), \( P \) is the capillary pressure, \( b \) is the Klinkenberg factor accounting for gas slippage effects.

(continued on next page)
Fig. 1—A mesh sketch of multiple hydraulic fractured horizontal shale gas well. Blue grids denote wellbore, red grids represent hydraulic fractures, green grids indicate natural fractures, and white grids stand for non-organic matter.

**Task 2:** Build a reservoir model containing stimulated reservoir volume to show the changing trend of water saturation and nanoparticle concentration at reservoir scale

*Fig. 1* depicts the reservoir model built for task 2.

**Task 3:** Compute and present the distribution of magnetic susceptibility of reservoir

Based on diverse sources of magnetism, the distribution of magnetic susceptibility of reservoir was computed and presented. The results of magnetic susceptibility are obtained from the same reservoir models with and without considering magnetism for nanoparticles. The results about the distribution of magnetic susceptibility of reservoir were also compared with some experimental data to validate the model’s accuracy and predictability.

**Task 4:** Run simulations of nuclear logs using a Monte-Carlo-based method

We inserted a hydraulic fracture into our previously created geometry in the middle of the formation. We used Monte Carlo N-Particle (MCNP) code to run two simulation cases, the first included proppant and water in the fracture. In the second case, we inserted neutron absorbing materials in the hydraulic fracture to change the response of the neutron detector. The goal is to quantify the effect that fractures and inserting neutron absorbing particles into the fracture have on the neutron porosity measurements.

**Accomplishments**

The mathematic model considering sub-divided pores media, various flow mechanisms, and mixed wettability is developed to describe the nanoparticles transport carried by a two-phase flow in shale reservoirs. The numerical results demonstrate the magnetic nanoparticles effectively enlarge the magnetic susceptibility of reservoirs (*Fig. 2*) and the magnitude of magnetic susceptibility is related to the permeability, water saturation and volume of pore media. In addition, the results are compared with and confirmed by some experimental results (*Fig. 3*), which provides more confidence to apply magnetic nanoparticles for producing enhanced signals from borehole geophysical devices.

For numerical simulation of neutron porosity measurements, the neutron detectors only detect thermal neutrons. Thus, we verified that our formations of interest were adequately thermalizing neutrons. *Fig. 4* shows the neutron source energy spectrum as well as the scattered-down neutron energy spectrum. The source energy distribution along with the scattered-down distribution can also be seen in *Fig. 4*. This confirms that our formation is sufficiently slowing down almost all neutrons which will allow us to obtain accurate detection results, and modify the detection of neutrons through use of neutron absorbing particles that are sensitive to thermal neutrons.

*Fig. 5* shows preliminary results of simulated neutron porosity logs in the fractured formation with and without the presence of neutron absorbing particles. Without neutron absorbing particles present, the neutron porosity log is insensitive to the presence of hydraulic fractures. When neutron absorbing particles are added, there is a sharp decline in the detector reaction rate in the near detector in the area close to the fracture, and a similar
As we expected from results in Fig. 5, addition of neutron absorbing particles has an effect on the detection of neutrons in the formation.

**Significance**
The mathematical model considering subdivided pore media and various flow mechanisms was developed to describe the nanoparticle transport in shale reservoirs, which could also show the distribution of magnetic susceptibility of reservoir with and without magnetic nanoparticles. This simulator can provide helpful guidelines for nanoparticles injection plans to enhance well logging signals and supply good reference for tracer flow in unconventional reservoirs.

The results of neutron porosity simulations in the presence of fractures confirms that neutron porosity measurements in the conventional sense are not sensitive to the addition of hydraulic fractures; however, when neutron absorbing particles are added in the hydraulic fracture, we do see sensitivity to the presence of fractures. This knowledge, and ability to enhance neutron porosity signals, will allow us to better characterize fracture networks using neutron porosity logs.

**Future Work**
The future work is to expand the reservoir scale to contain some un-fractured areas. Also some sensitivity analysis will be conducted, such as size and magnetic characteristics of nanoparticle, organic matter, fracture distribution and fracture conductivity. We will also quantify the required concentration of absorbing material that needs to be added to have a discernable effect on the neutron porosity measurements. Finally, the sensitivity of electromagnetic logs to the presence of fractures will be quantified using numerical simulations.

**References and Related Publications**


Enhanced In Situ Assessment of Petrophysical Properties and Kerogen Spatial Distribution in Organic-Rich Source Rocks using Well Logs

Abstract

This project aims to develop a new technique for reliable, real-time, and in-situ assessment of petrophysical properties and kerogen spatial distribution in organic-shale formations, which can tremendously impact production from these unconventional reservoirs. Petrophysical properties of organic-shale formations have been conventionally evaluated using laboratory experiments and well-log interpretations. The existing well-log interpretation methods, which are considered as the only real-time and reliable options for depth-by-depth formation evaluation, are mainly empirical and highly dependent on core calibration. On the other hand, reliability of core measurement techniques in organic-rich source rocks is still questionable. Furthermore, in-situ and real-time assessment of kerogen spatial distribution, which is known as an important factor in production, has not been possible so far. In summation, conventional formation evaluation techniques are usually not successful in organic-rich source rocks.

The proposed technique in this project is joint interpretation of dielectric, nuclear magnetic resonance (NMR), and electrical resistivity measurements for improved assessment of petrophysical properties of organic shale. To fulfill the objectives we propose (a) reliable pore-scale numerical simulations of dielectric, NMR, and electrical resistivity measurements, which eliminate the need for conventional empirical correlations and core calibration and takes into account the complex pore structure and the presence of organic matter and (b) combined interpretation of these measurements for improved petrophysical evaluation of organic-shale formations.

Objectives

The objective of this project is to improve assessment of fluids saturation, total pore space, pore structure, wettability, and kerogen spatial connectivity in organic-rich source rocks using well logs and core measurements.

Approach

In this project, we propose pore-scale numerical simulation of dielectric, NMR, and electrical resistivity in organic-rich source rocks, which can lead to reliable models for their interpretation and consequently to enhanced estimates of fluid saturations, kerogen network connectivity, and pore-space petrophysical characterization when combined with other borehole petrophysical measurements. The main tasks defined for this project are:

» Numerical simulations of dielectric, NMR, and electrical resistivity measurements;
» Quantify the impact of wettability and kerogen network connectivity on physical properties of the rock; and
» Joint interpretation of dielectric, electrical resistivity, and NMR measurements;

We will apply the proposed method on synthetic and field examples.

Accomplishments

Numerical Simulation and Joint Interpretation of Dielectric Permittivity and Electric Resistivity Measurement

We previously developed two numerical simulators for dielectric permittivity and electrical resistivity modeling in porous media. The inputs to these simulators are three-dimensional (3D) pore-scale images. We then introduced an analytical model that combines conductivity and permittivity measurements for assessment of water-filled porosity and...
hydrocarbon saturation. We observed an improvement in estimates of water-filled porosity compared to conventional methods in the case of organic-rich source rocks with complex pore structure. 

**Fig. 1** shows the correlation between the electrical directional tortuosity and the tortuosity-dependent coefficient of the water network. 

**Fig. 2** compares the water saturation estimated by the conventional Complex Reflection Index Model (CRIM) and that by the new model. The absolute relative errors in estimates of water saturation using our new model for ten synthetic organic-rich rock samples are less than 10%, no matter whether the kerogen is conductive or non-conductive.

**Impact of Tortuosity of the Pyrite Network on Estimates of Water Saturation: A Comparison between the New Method and Conventional Techniques**

In the case of synthetic organic-rich source rock samples, our simulation results confirm that not only the pore structure, but also spatial distribution and tortuosity of water, kerogen, and pyrite networks, affect the measurements of dielectric permittivity and electrical resistivity. Taking into account these parameters through the joint interpretation of dielectric and electrical resistivity measurements significantly improves assessment of hydrocarbon saturation. 

**Fig. 3** depicts the impact of the electrical directional tortuosity of the pyrite network on the relative errors in estimates of water saturation by the new dielectric permittivity model and CRIM. We observed that with the increase of the diffusive directional tortuosity of the pyrite network, the relative errors in estimates of water saturation decrease from 27% to 4% overestimation when we apply the CRIM.

**Significance**

The proposed project enables reliable well-log-based assessment of in situ petrophysical properties of organic-rich source rocks. Reliable estimates of these properties have not been possible so far with conventional approximations, even in the presence of numerous core measurements. Improved evaluation of in situ petrophysical properties of organic-shale formations helps in optimizing the number of required fracture stages to maximize production and to minimize environmental impacts and water requirements.

**Future Work**

In the next step, the NMR and dielectric modeling procedures will be further modified for the case of organic shale. Furthermore, we will investigate sensitivity of NMR measurements to pore structure and wettability.

**References and Related Publications**


Experimental Study of Confinement Effects on Hydrocarbon Phase Behavior in Nano-Scale Capillaries

Abstract
Phase behavior in shale remains a challenging problem in the petroleum industry due to many complexities. One complexity arises from strong surface-fluid interactions in shale nano-scale pores. These interactions can lead to a heterogeneous distribution of molecules, which conventional bulk-phase thermodynamics fail to describe. The majority of current models for phase behavior in shale are based on bulk-phase thermodynamics. There are currently no experimental data for hydrocarbon phase behavior in shale systems. In this project, a special Texas A&M University research team is going to investigate the phase change in nano-scale capillaries using the combination of a nanochannel device and epi-fluorescence microscopy, and measure the effect of confinement on hydrocarbon phase behavior in shale. We will then extend the experiments by modifying the model material’s surface both chemically and topographically. We will use molecular simulation to gain insight into the experimental results.

Objectives
The main outcome of this project will be reliable experimental data that measures the effect of confinement on the phase behavior in shale systems. This experimental data can be used to test various models suggested in the literature to predict the phase behavior in shale. Also, we expect to publish the project findings in several peer-reviewed journals and conferences.

Approach
In this work, we will investigate confinement effect of nano-channels in phase behavior of hydrocarbons. We will use nano-chips made of glass or similar transparent material in order to confine the fluid and observe the effect of confinement on bubble point temperature and pressure shift. In order to observe hydrocarbon bubble point, confocal microscopy will be used as a very accurate tool.

Accomplishments
The priority is to find the best nano-channel system in which we can neglect all the possible errors that affect measurements and make the experiments repeatable. Considering previous nanofluidic chip designs (Duan and Majumdar 2010; Wu et al. 2014; Liu et al. 2014), we came up with two different chip geometries. The first one includes twenty nano-channels in which we want to observe confinement effect, and four reservoirs for injecting hydrocarbons (Fig. 1). The reason we chose this system is that by making twenty parallel channels, we can decrease the error of unwanted factors on a single channel. Additionally, if one or some of the channels plug because of debris, we still have other channels to observe. The second design, on the other hand, has a single nano-channel bounded by two reservoirs (Fig. 2). We have chosen this geometry in order to focus on a single channel while eliminating possible effects of other channels. You can see AutoCAD plots of each chip design in the figures.

Significance
Several researchers have recently studied the phase behavior of petroleum fluids in shale systems. There is a general agreement that the confined pressure/volume/temperature (PVT) properties in shale are substantially different from the corresponding build properties. These differences have significant impact on the prediction of well performance and ultimate recovery in unconventional reservoirs. For example, in a number of light oil shale reservoirs, the sampled fluids are strongly

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Fig. 1

Project 3.2.21
Experimental Study of Confinement Effects on Hydrocarbon Phase Behavior in Nano-Scale Capillaries

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undersaturated at bulk conditions but the gas-oil-ratio increases significantly at the early stage of production. There is currently no reliable experimental data for the conditions of interest.

**Future Work**

We will complete a set of experiments investigating bubble point temperature shift, then we will focus at high pressures and measure bubble point pressure shift. We will then model our experiments using molecular dynamic simulation.

**References and Related Publications**


Experimental Study of Confinement Effects on Hydrocarbon Phase Behavior in Nano-Scale Capillaries

Abstract
Phase behavior in shale remains a challenging problem in the petroleum industry due to many complexities. One complexity arises from strong surface-fluid interactions in shale nano-scale pores. These interactions can lead to a heterogeneous distribution of molecules, which conventional bulk-phase thermodynamics fail to describe. The majority of current models for phase behavior in shale are based on bulk-phase thermodynamics. There are currently no experimental data for hydrocarbon phase behavior in shale systems. In this project, we are going to investigate the phase change in nano-scale capillaries using experiments. The team will use experimental approaches based upon selected “model” porous materials: differential scanning calorimetry to accurately measure the effect of confinement on hydrocarbon phase behavior in shale. We will then extend the experiments by modifying the simulation to gain insight into the experimental results.

Objectives
The main outcome of this project will be reliable experimental data that measures the effect of confinement on the phase behavior in shale systems. These experimental data can be used to test various models suggested in the literature to predict the phase behavior in shale. Also, we expect publications of the project findings in several peer-reviewed journals and conferences.

Approach
The differential scanning calorimetry method measures the difference in the amount of heat required to increase the temperature of a confined fluid sample to detect a phase transition. We saturate the controlled-pore glasses with a hydrocarbon liquid (e.g., n-decane). Then we change the temperature of the sample at atmospheric pressure and measure the temperature that the gas phase forms (i.e., bubble-point temperature).

Accomplishments
Differential scanning calorimetry (DSC) was tested with bulk pure hydrocarbon (Fig. 1). The bubble point of bulk octane was found at the onset point 125.60°C, matching well with literature (Lyons and Plisga 2011). This result suggests that DSC is a practical method in measuring bubble points.

Various pore diameters of controlled-pore glasses were obtained from the commercial source. The porous glasses were cleaned with nitric acid and then reacted with hexamethyldisilazane to deliver the hydrophobic surface. Then the porous materials were soaked with hydrocarbons (e.g., octane) overnight and the bubble point of the confined liquids were measure by differential scanning calorimetry. The initial results were shown in Fig 2: in 35 nm controlled-pore glasses the bubble point 124.94°C was observed slightly less than that of bulk liquid.

Significance
Several researchers have recently studied the phase behavior of petroleum fluids in shale systems. There is a general agreement that the confined PVT properties in shale are substantially different from the corresponding build properties. These differences have significant impact on the prediction of well performance and ultimate recovery in unconventional reservoirs. For example, in a number of light oil shale reservoirs, the sampled fluids are strongly undersaturated at bulk conditions but the gas-oil-ratio increases significantly at the early stage of production. There are currently no reliable experimental data for the conditions of interest.
**Future Work**

» Measure bubble points of various hydrocarbons and mixtures confined in porous glasses of other specific pore diameter.

» Use molecular simulation to model the bubble points of confined hydrocarbons.

**References and Related Publications**


![Fig. 2–Bubble point of octane in 35 nm controlled-pore glasses](image)
Low-Salinity Waterflooding in Sandstone Reservoirs

Abstract
Extensive experimental work has indicated that low-salinity waterflooding (LSW) is an enhanced oil recovery technique that improves oil recovery by lowering and optimizing the salinity of the injected water. Most of the low-salinity waterflooding studies focused on the injection brine salinity and composition. The question remains—how will the salinity and composition of reservoir connate water affect the low-salinity waterflooding performance? In this paper, different connate water compositions were used (total dissolved solids varying from 1,550 to 174,156 ppm) to investigate the role of reservoir connate water on the performance of low-salinity waterflooding.

Nine spontaneous imbibition (SI) experiments and six coreflood experiments were performed. Two sandstone types (Bandera and Buff Berea) with different clay contents and stock-tank crude oil samples were used in all experiments. This work describes the experimental studies of the spontaneous imbibition of oil by low-salinity and high-salinity brines using 20 in. length outcrop sandstone samples.

The spontaneous imbibition study focused on the effect of connate water composition and temperature (77° and 150°F) on the performance of LSW. Imbibition brine samples were analyzed after each experiment. The coreflood experiments were conducted using 6 in. length outcrop Buff Berea sandstone cores at 160°F and 500 psi. Oil recovery and pressure drop were observed and analyzed after each coreflood experiment to examine the effect of the connate water composition (Na+, Ca2+, and Mg2+) on the performance of the low-salinity waterflooding in the secondary recovery mode.

Objectives
The main objectives for this work are:

» Evaluate the potential of LSW on the performance of oil recovery improvement using Buff Berea and Bandera sandstone cores.

» Investigate the role of the reservoir connate water composition (Na+, Ca2+, and Mg2+) on the performance of the LSW.

» Examine the effect of the salinity of the reservoir connate water.

» Test the effect of temperature on the performance of the LSW recovery.

Approach
Mineral Identification
The sandstone samples were evaluated using X-ray powder diffraction (XRD), scanning electron microscopy (SEM), X-ray fluorescence (XRF), and average pore-throat radius.

Coreflood Tests
Six experiments were run using Buff Berea sandstone samples. Core samples with 1.5 in. diameter and 6 in. length were used.

Spontaneous Imbibition
Visualization of SI into circular capillary tubes was studied. The procedure of Cuiec (1984) using an Amott-wettability cell was followed. Core samples with 1.5 in. diameter and 20 in. length were used.
Accomplishments

Results of Spontaneous Imbibition Experiments

Three SI experiments were conducted using Buff Berea sandstone: cores O-1, O-2, and O-3. Core O-1 was saturated with connate water containing only monovalent cations (Na+). The salinity of the connate water for this core before the start of test was approximately 54,400 ppm. Core O-2 was saturated with high salinity conventional connate water (174,156 ppm). Core O-3 was saturated with reservoir connate water containing only divalent cations (Ca2+ and Mg2+). The concentration of Ca2+ and Mg2+ in the connate water was 10,600 and 1,610 ppm, respectively. NaCl brine (5,000 ppm) was used as the imbibition brine.

Two SI experiments were then performed at a temperature of 150°F using Buff Berea sandstone: cores O-4 and O-5. The objective of these two experiments was to study the influence of temperature on the recovery performance using SI tests. Cores O-4 and O-5 were saturated with high salinity conventional connate water (174,156 ppm) similar to core O-2. One of the cores was immersed in low-salinity brine (5,000 ppm NaCl), while the other core was immersed in brine with the same composition of the connate water (H-1) to simulate conventional waterflooding. The two cells were then placed in an oven set at 150°F.

In the second set of experiments, the influence of connate water brine composition and the clay content on oil recoveries from Bandera sandstone was also investigated. The test was performed on four Bandera sandstone cores, of which one (R-3) was saturated with connate water containing only monovalent cations (Na+) with salinity of 54,400 ppm. The second and third cores (R-1 and R-4) were saturated with high salinity conventional connate water (174,156 ppm). Core R-2 was saturated with connate water containing only divalent cations (Ca2+ and Mg2+). The concentration of Ca2+ and Mg2+ in the connate water was 10,600 and 1,610 ppm, respectively. In the low-salinity water imbibition, NaCl brine (5,000 ppm) was used as the imbibition brine for cores R-2, R-3, and R-4. In contrast, conventional connate water (174,156 ppm) was used as the imbibition brine for core R-1 to simulate the conventional waterflooding and to compare oil recovery values with those obtained from core R-4. Water imbibition was monitored versus time on a daily basis for a period of approximately 93 days by measuring the oil volume.

Results of Coreflood Experiments

All coreflood experiments were conducted with the same temperature of 160°F, the same back flow pressure of 500 psi, and the same overburden pressure of 1800 psi. Lager et al. (2006) stated that the mechanism behind the incremental recovery from LSW was the free multi-charged cations (MIE). Nasralla et al. (2011) proposed that the surface charge of solids was affected by the cation type of the injected brine; the Ca2+ and Mg2+ result in weak negative charges of Grey Berea sandstone, while the Na+ ions make the charges strongly negative.

Low-salinity brine had a significant positive effect on oil recovery for sandstone cores saturated with divalent cations (Ca+2 and Mg+2). The magnitude of incremental oil recovery increased from 51.9% to 58.9% OOIP when the reservoir connate water salinity increased (continued on next page)
Summary of the six coreflood experiments

<table>
<thead>
<tr>
<th>Core #</th>
<th>Initial Connate Water Composition</th>
<th>Injected Brine Composition</th>
<th>Injection Rate (ml/min)</th>
<th>Slug Size (PV)</th>
<th>Incremental Oil Recovery (% OOIP)</th>
<th>Total Oil Recovery (% OOIP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>S-2</td>
<td>Ca(^{2+}) 10,600 ppm and Mg(^{2+}) 1,610 ppm</td>
<td>NaCl (5,000 ppm)</td>
<td>0.5</td>
<td>6.25</td>
<td>57.4</td>
<td>57.4</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>1</td>
<td>4.4</td>
<td>1.46</td>
<td>58.9</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>2</td>
<td>4.4</td>
<td>0</td>
<td>58.9</td>
</tr>
<tr>
<td>S-4</td>
<td>CW (H-1) High-Salinity Conventional Connate Water</td>
<td>NaCl (5,000 ppm)</td>
<td>0.5</td>
<td>6.75</td>
<td>40.7</td>
<td>40.7</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>1</td>
<td>5.0</td>
<td>3.5</td>
<td>44.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>2</td>
<td>4.2</td>
<td>0</td>
<td>44.2</td>
</tr>
<tr>
<td>S-7</td>
<td>Na(^+) 54,400 ppm</td>
<td>NaCl (5,000 ppm)</td>
<td>0.5</td>
<td>6.3</td>
<td>35.8</td>
<td>35.8</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>1</td>
<td>4.0</td>
<td>1.3</td>
<td>37.1</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>2</td>
<td>3.6</td>
<td>0</td>
<td>37.1</td>
</tr>
<tr>
<td>S-1</td>
<td>Ca(^{2+}) 633 ppm and Mg(^{2+}) 133 ppm</td>
<td>NaCl (500 ppm)</td>
<td>0.5</td>
<td>8.2</td>
<td>51.9</td>
<td>51.9</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>1</td>
<td>3.1</td>
<td>0</td>
<td>51.9</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>2</td>
<td>5.7</td>
<td>0</td>
<td>51.9</td>
</tr>
<tr>
<td>S-5</td>
<td>Na(^+) 610 ppm</td>
<td>NaCl (500 ppm)</td>
<td>0.5</td>
<td>7.5</td>
<td>35.4</td>
<td>35.4</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>1</td>
<td>4.2</td>
<td>0.5</td>
<td>35.9</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>2</td>
<td>3.9</td>
<td>0</td>
<td>35.9</td>
</tr>
<tr>
<td>S-9</td>
<td>Low-Salinity Conventional Connate Water</td>
<td>NaCl (500 ppm)</td>
<td>0.5</td>
<td>6.1</td>
<td>43.2</td>
<td>43.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>1</td>
<td>5.1</td>
<td>0</td>
<td>43.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>2</td>
<td>4.7</td>
<td>0</td>
<td>43.2</td>
</tr>
</tbody>
</table>

from 3,420 to 36,350 ppm. In contrast, increasing the monovalent cations (Na\(^+\)) from 1,550 to 137,670 ppm showed a small improvement in oil recovery (1.2% OOIP).

Lee et al. (2010) suggested that the polar and charged components of the oil are held on the surface of the clay by divalent ions. During LSW the divalent cations were exchanged for monovalent cations which no longer held the oil to the surface. They concluded that the exchange of divalent ions for monovalent ions at low concentrations could significantly enhance the thickness of the water layer on the mineral surface.

Austad et al. (2010) proposed a chemical mechanism for wettability alteration by desorption of adsorbed cations from clay present in the sandstone that was caused by injection of LSW. The Ca\(^{2+}\) was substituted by H\(^+\) on the clay surface and promoted desorption of organic material from the clay as a result of an ordinary acid-base reaction. Based on this suggested chemical mechanism, clay must be present in the sandstone and polar components (acidic and/or basic material) must be present in the crude oil. The connate water also must contain active cations, such as Ca\(^{2+}\).

Conclusions

Low-salinity waterflooding showed a high potential to improve oil recovery for Buff Berea and Bandera sandstone in the spontaneous imbibition experiments. For high permeability Buff Berea cores (164-207.7 md), the spontaneous imbibition oil recovery ranged from 38% to 69% OOIP, while oil recovery of the low permeability Bandera cores (31.1-39.2 md) ranged from 20% to 51.5% OOIP at 77°F and 14.7 psia. As the temperature increased from 77° to 150°F, an additional oil recovery up to 15.4% of OOIP was observed by spontaneous imbibition for Buff Berea cores.

Reservoir connate water composition had a dominant influence on the oil recovery rate. The changes in the ion composition of reservoir connate water showed a measurable change in the oil production trend. The Ca\(^{2+}\), Mg\(^{2+}\), and Na\(^+\) ions play a key role in oil mobilization in different sandstone rocks. Reservoir cores saturated with connate water containing divalent cations of Ca\(^{2+}\) and Mg\(^{2+}\) showed higher oil recovery for cores saturated with monovalent cations Na\(^+\). The oil recovery from the coreflood tests for the Buff Berea cores ranged from 35.9% to 58.9% OOIP. The oil recovery decreased when the salinity of reservoir connate-water decreased. Low-salinity waterflooding had a significant positive effect on oil recovery for sandstone cores saturated with divalent cations (Ca\(^{2+}\) and Mg\(^{2+}\)) compared to cores saturated with monovalent cations (Na\(^+\)). The incremental oil recovery increased from 51.9% to 58.9% OOIP when the reservoir connate water salinity increased from 3,420 to 36,350 ppm. In contrast, increasing the monovalent cations (Na\(^+\)) from 1,550 to 137,670 ppm resulted in a slight increase in oil recovery (1.2% OOIP).

Future Work

In order to achieve our objectives, the following will be required to build the methodology of this research:

- Investigate the role of the clay content and type on the performance LSW in secondary and tertiary recovery modes.
Examine the effect of the crude oil polar components and sour crude oil on the performance of the LSW.

References and Related Publications


Iteratively Coupled Fluid Flow-Geomechanics Simulation based on Statistically Estimated Porosity and Equivalent Permeability using Fractal and Statistical Methods

Abstract

Permeability and porosity are key parameters for reservoir simulation. Porosity is essential for the estimation of original oil/gas in place or for the calculation of saturation and permeability. For the naturally fractured reservoirs (NFR) simulation, when matrix porosity is negligible, it is very important to estimate proper fracture porosity and permeability to obtain more accurate simulation results. However, it is very difficult to measure and estimate these parameters due to many uncertainties, such as high heterogeneity of fluid and fracture properties, scale discrepancy errors of logging data, and so on. There is also not too much discussion about the estimation of fracture network permeability.

Through this study, we estimated the fracture network geometry information, such as porosity and equivalent permeability distribution, using fractal and statistical methods. Also, we estimated the interaction effect between fluid flow and geomechanics on reservoir simulation through iteratively coupled simulation analysis. The results of this study will contribute to proper evaluation of fluid flow in a stress sensitive naturally fractured reservoir.

Objectives

- Calculate initial porosity $\phi_0$ using Fractal and statistical method.
- Develop equivalent permeability calculation code and calculate equivalent permeability using generated fracture network data by FDFN code.
- Develop iteratively coupled fluid flow-geomechanics simulation code.

Approach

The basic equations for fluid flow in a deformable porous medium consist of mass conservation equations, energy conservation equation, Darcy’s law and equations of state depicting fluid characteristics. Whereas the basic equations for solid deformation consist of equilibrium equations via momentum conservation equation, strain-displacement relations and constitutive equation, in order to develop those conservation equations, a continuum approach is employed.

Equivalent Fracture Permeability

Oda (1985) considered fractured rock mass as homogeneous, anisotropic porous media. In this approach, fluid flow follows Darcy’s law and permeability properties are related to the fracture geometry. Oda used permeability tensor notation which represents permeability orientation and magnitude, and he proposed stochastic permeability expression. A modification of Oda’s method (Du and Wong 2007) is used in this study, which considers stress change effect due to injection/production of the reservoir. For that, normal stress to each fracture is calculated and closing/opening effects of apertures on the change of the fracture permeability can be reflected.

True Porosity and Reservoir Porosity

As the volume coupling is employed, porosity is the coupling parameter in the simulation. In the fluid flow analysis in finite difference method (FDM), the bulk volume of the reservoir domain is regarded to be constant during the simulation (Settari and Mourits 1998), whereas the bulk volume and pore volume in the geomechanics finite element method
(FEM) model are changed during the simulation. Therefore, the true porosity calculated from a geomechanics model cannot be directly used in the fluid flow model and has to be converted to reservoir porosity based on the constant bulk volume for the corresponding grid block (Settari and Mourits 1998; Chin, Raghavan, and Thomas 2000; Chin et al. 2002; Thomas et al. 2003; Tran, Settari, and Nghiem 2004; Pan, Sepehrnoori, and Chin 2009).

The equations of the true porosity and the reservoir porosity are given by:

\[ \phi^* = 1 - (1 - \phi_0)e^{-\varepsilon_x} \]  

\[ \phi = \frac{1 - \phi_0}{1 - \phi^*} \phi^* = e^{-\varepsilon_x} \phi^* \approx \phi^*(1 - \varepsilon_x) \]

or,

\[ \phi^* = 1 - (1 - \phi_0)e^{-\varepsilon_x} \]  

\[ \phi = \frac{1 - \phi_0}{1 - \phi^*} \phi^* = e^{-\varepsilon_x} - (1 - \phi_0) \]

where, \( \phi^* \) is the true porosity from geomechanics model, \( \varepsilon_x \) is the volumetric strains, \( \phi \) is the reservoir porosity for fluid flow model and \( \phi_0 \) is the initial porosity. Initial porosity is computed from the FDFN model. Updated reservoir porosity using Eq. (4) from the geomechanics model is passed back to the fluid flow model during the coupling iteration.

**Iterative Coupling Method**

In the iterative coupling scheme, the basic equations for fluid flow and the geomechanics model are solved independently.

![Fig. 2–Comparison of iterative fluid flow-geomechanics coupling and fluid flow FDM results](continued on next page)
The pore pressure is calculated by the fluid flow FDM model and the changes of the displacement, volumetric strains and stresses of solid medium are calculated by the geomechanics FEM model. Through the coupling module, the computed data are exchanged until the convergence of the coupling iteration is below a given tolerance.

**Accomplishments**

Synthetic simulation conditions were considered for equivalent permeability estimation and iterative coupling simulation. Fracture porosity was directly calculated from generated natural-like fracture aperture distribution.

To generate the fracture network, we simulated 1000 fracture maps using Monte Carlo methods for each case study. We then calculated a cumulative distribution function plot of generated fractures and selected the P50 fracture network because P50 could be considered the most likely fracture condition with given data. After generating a P50 fracture map, grid numbers used in each simulation were estimated from the plot of the average directional equivalent permeability versus grid numbers.

An equivalent permeability calculation code was developed using full tensor scheme and modified Oda’s methods. From the results of the equivalent permeability distribution estimation, it was found that calculated equivalent permeability effectively reflected the heterogeneous and anisotropic characteristics of the fracture networks.

The 2D iteratively coupled fluid flow and geomechanics simulation code was developed considering calculated fracture porosity and equivalent permeability. We employed fracture theory and statistics for coupling simulation. The coupling code was composed of two schemes; one was the fluid flow FDM code using Newton-Raphson iteration method and the other one was the elasto-plastic geomechanics FEM code using Mohr-Coulomb failure criterion. The coupling code was verified by solving Terzaghi’s one-dimensional consolidation problem. From the comparison of two results by analytical solution and coupling simulation, the coupling code showed a good match with the analytical solution.

We used the volume coupling scheme for this study. For that, the code calculated true porosity and reservoir porosity, respectively. We used non-linear porosity formula related to volumetric strains for the iterative coupling code instead of using a linear porosity equation widely used in traditional reservoir simulation.

The 2D water injection and oil production cases were simulated. For that, we considered two case studies with different permeability distribution; one had isotropic heterogeneous permeability distribution and the other had the calculated equivalent permeability distribution from FDFN results. Simulation results from case studies indicated that an understanding of the interaction between fluid flow and geomechanics was important to predict proper production performance. The interaction effects resulted in the time shift during the production simulation. Porosity was reduced by an increase of effective stress due to production, and it resulted in the increase of fluid velocity.
Abstract
The overall goal of this study is to generate discrete fracture networks (DFN) using microseismic and core data from a naturally fractured reservoir that has been hydraulically stimulated. To improve fracture characterization, a methodology based on source mechanisms estimations is developed with the aim to distinguish the two natural fracture sets present in the reservoir. Source mechanisms estimation is a geophysical processing technique that can provide orientation and rupture modes of seismic events. However an intermediate step, moment tensor inversion, is needed. The main challenge is that one element of the moment tensor is completely undetermined by the limited azimuthal acquisition coverage; thus, some kind of assumption needs to be considered to complete the missing element. In this work, it is assumed that the microseisms occur mainly as a consequence of the natural fractures reactivation, thus source dip and strike are known. For the discrete fracture generation, a semi-stochastic technique is proposed, which combines information from the source mechanisms estimations, the microseismic report, and the core analysis report.

The two main contributions of this work are that a methodology to improve natural fracture characterization is proposed (which incorporates micro seismic data to distinguish the fracture sets known to be present), and that a semi-stochastic technique to generate discrete fracture networks (which combines microseismic information and core data) is proposed and implemented as well.

Objectives
- Analyze microseismic data from selected events and propose a processing technique to find source mechanisms applying strike and dip constraints. Attenuation effects will also be considered in the forward model.
- Proposed a semi-stochastic method to generate discrete fracture networks, which combines the source mechanisms results, microseismic event location, and the core analysis report.

Approach
Source mechanisms of Microseismic Events
Assuming that all components $M_{ij}$ of the seismic moment tensor $M$ have the same time dependence $s(t)$, the forward model to simulate displacement components $U_i$ at an arbitrary position $x$ at time $t$ can be written using indicial notation as (Jost and Herrmann 1989):

$$U_i(x, t) = [G_{ik,j} * s(t)] M_{kj}$$

Where $G_{ik,j}$ denotes the first spatial derivative of the Green’s function and represents displacements due to couples or dipoles of impulsive forces, $s(t)$ is the source time function and represents the slip dependence on time, and * denotes convolution.

The moment tensor describes the properties of the source and the Green’s function describes the properties of the medium in which the source is situated. Assuming that the medium is homogenous and isotropic, $s(t)$ is a step function and the 3-component receivers are placed several wavelengths far from the source, amplitude components $A_i$ observed at the 3-component receivers can be derived from Eq. (38) and expressed as (Vavryčuk 2007):

(continued on next page)
\[ A_i^W = G_{ik,j}^w M_{kj} \]

Where W refers to P or S phase and \( G_{ik,j}^P \) and \( G_{ik,j}^S \) are defined as:

\[
G_{ik,j}^P = \frac{n_i n_k n_j}{4\pi \rho V_p^3 r} \\
G_{ik,j}^S = -\frac{(n_i n_k - \delta_{ik})n_j}{4\pi \rho V_s^3 r}
\]

Where \( n_i, n_k \) and \( n_j \) are the components of the unit vector connecting the source to the ith-component receiver; \( \delta_{ik} \) is the Kronecker delta; \( \rho \) is the density of the medium, \( V_p \) and \( V_s \) are the compressional and shear velocities of the medium respectively and \( r \) is the distance from the source to the receiver.

The moment tensor \( M \) for the forward model can be determined from proposed sources using a slight modification of Eq. (7). After assuming that the product \( A d \mu \) is equal to one:

\[
M = \frac{A}{\mu} (\hat{d} \cdot \hat{n} I) + (\hat{n} \hat{d} + \hat{d} \hat{n})
\]

The second order moment tensor \( M \) is symmetric, therefore it only has six independent components which can be written as the elements of a vector \( \mathbf{M} = (M_{11}, M_{22}, M_{33}, M_{12}, M_{13}, M_{23}) \). Then the equation becomes:

\[
\mathbf{A} = \mathbf{G} \mathbf{M}
\]

Where \( \mathbf{A} \) is the vector composed of the amplitudes from all the 3-component receivers, \( \mathbf{G} \) has as many rows as the number of elements in \( \mathbf{A} \) and as many columns as moment vector components.

For the inverse problem, \( \mathbf{M} \) can be estimated by least squares minimization:

\[
\hat{\mathbf{M}} = [\mathbf{G}^T \mathbf{G}]^{-1} \mathbf{G}^T \mathbf{A}
\]

Since for the present field case study, the amplitude data have been recorded from a single vertical array of receivers, one diagonal component of the moment tensor is completely undetermined (Vavryčuk 2007). Thus, only the five recoverable components of the moment tensor will be estimated by least squares inversion. To be able to estimate the source mechanism, an assumption regarding the source has to be made. In this case, it is assumed that the seismicity is primarily induced by the reactivation of the natural fractures. Thus dip and strike were constrained to the values of the two fracture sets. From these two possible solutions, the one with the best fit was selected.

**Discrete Fracture Generation**

A semi-stochastic technique is proposed for a 2D discrete fracture generation constrained by microseismic locations and estimated moment tensors. Information from core data, such as fracture spacing and orientation, is also incorporated to create the probability density functions from which fracture orientation, length and aperture are sampled. The methodology considers that there is a single fracture passing through each microseismic event. To incorporate microseismic location uncertainty, a random location is considered for each microseismic event within the area of its error ellipse. The number of events cor-
responding to each of the two fracture sets was derived from core spacing information. The assignment of fracture length considered the degree of mineralization of the natural fracture sets. For the unmineralized set, a power law distribution was considered, and for the mineralized one, the source radius information was incorporated. Finally fracture orientation was included for those events without moment tensor estimation. It was assumed that fracture orientation followed a Fisher distribution whose parameters were derived from core data. Finally, fracture aperture was sampled from a log normal distribution.

**Accomplishments**

Discrete Fracture Generation including source mechanisms estimations

Fig. 1 shows the 71 reported microseismic events for stage 5. The green dots are the microseismic events for which source mechanisms solutions were estimated, thus the orientation of the reactivated natural fractures are known for these events.

Fig. 2 shows one realization of the semi-stochastic DFN generation for one stimulation stage. The natural fractures in black are the ones connected to the hydraulic fracture and the wellbore. The purple lines represent the complex path of the hydraulic fracture.

**Future Work**

Complete the analysis for all the hydraulic fracture stages of this well. Proceed with a 3D DFN.

**References and Related Publications**


Project 3.5.14  
Characterization and Simulation of Discrete Fracture Networks

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Integrated Workflow: Generation of Microseismically-Constrained Discrete Fracture Network and Optimized PEBI Grids

Step 1: Incorporation of microseismic event locations
In Step 1, micro-seismic events are shown for one stage of a fracture stimulation job. The dots in Step 1 are events recorded during propagation of the hydraulic fracture. The data points in the Step 1 stage is determined by a series of events that are recorded in an off-set vertical well using geophones in that observation well. Each micro-seismic even is analyzed for signal to noise ratio to ensure an adequate signal per micro-seismic event.

Step 2: Discrete Fracture Network (DFN) generation
Once that is accomplished then the event is used to locate and characterize the event as 1) connected natural fractures 2) non-connected natural fractures and 3) hydraulic fractures all of which are relative to the trajectory of the lateral as shown with the brown dotted line. Once this process is complete, based on the natural fracture populations observed and characterized from horizontal core, a discrete fracture network is generated that conforms to the micro-seismic. The Discrete Fracture Network (DFN) conforms to horizontal core and micro-seismic data as shown in Step 2.

Step 3: PEBI grid generation
We then use optimized-based gridding algorithms to create a sophisticated perpendicular bisector (PEBI) mesh that represents that particular fracture stage as shown in Step 3. The connection list for the DFN can be used to build a very accurate simulation grid that reflects the nature of the hydraulic, natural and combination of these fracturing events. The individual fractures each have aperture distributions that are log-normal and conform to well-established geological principles regarding fracture strike, spacing, length and aperture distribution. This grid can then be used to simulate behavior in complicated natural fracture systems that are closely representative to actual fracture systems.
**Numerical Simulation of unconventional reservoirs with PEBI Grids**

**Abstract**
This research will develop characterization methods for naturally fractured reservoirs using outcrop maps, microseismic data, and fractal theory, then develop unstructured gridding algorithms, and finally perform fluid flow simulations and analyze pressure transient behaviors.

**Objectives**
- Develop better reservoir characterization techniques for hydraulic stimulated naturally fractured reservoirs using microseismic events, outcrop data, and fractal theory.
- Develop more accurate, robust and efficient meshing and discretization techniques for complex 3D fracture geometries with partial well completions.
- Investigate multiphase and geomechanic effects of the resulting complex fracture networks on production performance.

**Approach**
We plan to apply fractal theory to characterize naturally fractured reservoirs, and generate fractal discrete fracture networks (DFN) based on microseismic data, outcrop data, and well log data. We will also apply an unstructured Voronoi grid to generate simulation meshes of fractured reservoirs for finite-volume based simulators. During the process of mesh generation, we will first build protection areas with fixed Voronoi cells to conform to fracture geometries and honor non-uniform aperture distributions, and then use a distance function and optimization algorithms to implement local grid refinement around fracture intersections and tips. Finally, we will perform reservoir simulations and sensitivity analysis to study the effect of natural fracture parameters as well as unstructured mesh related parameters on production performance and well testing behavior.

**Accomplishments**
Prior similar research on this project developed an unstructured 2.5D perpendicular bisector (PEBI) workflow – both preprocessor and postprocessor. Previous research also developed an unstructured 2.5D PEBI generator in Fig. 1 to honor both complex fracture geometries and non-uniform aperture distributions. Our work investigated the fractal parameters of natural fractures such as fracture density, length and clustering on production performance of hydraulic fractured wells, as seen in paper SPE 170703, and investigated unstructured meshing related parameters such as background mesh density, mesh size, mesh type, and fracture refinement on production performance of hydraulic fractured wells. We managed to implement DFN generation based on microseismic data, outcrop data, and well logs (in collaboration with Edith Sotelo Gamboa) as seen in Fig. 2a and Fig. 2b, and we performed well testing analysis and compared simulation results as seen in Fig. 3a and Fig. 3b.

**Significance**
Proposed mesh generation algorithms solve the issue of how to generate high quality simulation grids for complex fracture networks, which is better than current commercial software packages such as Kappa and Mangrove.

(continued on next page)
This project will combine the microseismic data and fractal theory to better understand the resulting complex fracture networks, and try to incorporate geomechanic models into the workflow.

**Future Work**

» Generate a 3D DFN for natural fractures using microseismic data and other field information such as core and log data.

» Generate a 3D DFN for hydraulic fractures based on a geomechanical model that describes the fracture propagation in a naturally fractured medium.

» Develop a 3D PEBI grid capable of discretizing the space containing the natural and hydraulic DFN.

» Test the previous integrated workflow by running different reservoir simulation cases.
Integrated Fracture Placement and Design Optimization in Unconventional Gas Reservoirs

Abstract

To increase shale gas reserves and to develop them economically, it is necessary to place horizontal wellbores optimally and space hydraulic fracture (HF) stages along them in a way that yields the highest net present values (NPVs). This study presents an integrated optimization framework based on an evolutionary algorithm that allows enhanced production from shale gas formations and provides a solid foundation for future field-scale application. Our project provides an in-depth testing of this genetic algorithm and its application to the optimization of HF stages spacing and half-length as well as choosing the optimal number of horizontal wellbores. The results demonstrate that the framework is effective in optimizing HF stages design and well placement in shale gas models.

Objectives

The main objectives of the project is the implementation and testing of the stochastic evolutionary algorithm and its application to the problem of optimization of HF number, spacing, and half-length, as well as the number of horizontal wells in one integrated framework.

Approach

Nowadays, reservoir simulation and production optimization experts rely on heuristic methods when it comes to optimization of the number of HF stages and their spacing. Often the problem is excessively constrained due to difficulty with assessment of too many parameters that are optimized in a non-systematic manner. To address these challenges, we propose an integrated framework that helps the experts search the parameters domain in a systematic fashion and customize the search criteria based on the objectives. This goal is impossible to achieve without a reliable optimization algorithm that can be used efficiently as an engine in the heart of the integrated workflow.

Genetic Algorithm (GA) is one of the most popular stochastic derivative-free optimization methods that mimics natural selection and evolution (Holland, 1975). For the discrete problem of placing HF stages along a single horizontal wellbore and optimizing their half-length, binary GA is a suitable option. Thus, the optimization problem that GA solves can be described mathematically as follows:

\[
\begin{align*}
\max \ NPV(u) \\
\text{s.t. } \bar{u}_i \leq n_{l_{\max}} \\
\bar{u}_i \geq n_{l_{\min}} \\
\bar{u}_i \leq n_{l_{\max}} \\
\bar{u}_i \geq n_{l_{\min}} \\
i = 1, 2, ..., n.
\end{align*}
\] (1)

Here, \(\bar{u}_i\) refers to the portion of a chromosome that encodes the number of horizontal producer wells, \(n_{l_{\max}}\) is maximum feasible number of wells, \(n_{l_{\min}}\) is minimum feasible number of wells.

\[
NPV = \sum_{p=1}^{P} \left( \sum_{k=1}^{K} \frac{(Q_g^k \cdot r_g - Q_w^k \cdot r_w - 0) \cdot \Delta t^k}{(1 + b)^{t_k/365}} \ight.
\]

\[
- \left( C_w + N_{HF} (C_{fb} + C_{fl} x_{length}) + L_w C_p \right). \] (2)

(continued on next page)
<table>
<thead>
<tr>
<th>PARAMETER</th>
<th>VALUE</th>
<th>UNITS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Model width</td>
<td>1420</td>
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</tr>
<tr>
<td>Model length</td>
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<td>ft</td>
</tr>
<tr>
<td>Model thickness</td>
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<td>ft</td>
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<td>Reservoir temperature</td>
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<tr>
<td>Rock density</td>
<td>161</td>
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<tr>
<td>Matrix porosity</td>
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<td>%</td>
</tr>
<tr>
<td>Producing bottom hole pressure</td>
<td>500</td>
<td>psi</td>
</tr>
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<td>Initial reservoir pressure</td>
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<td>psi</td>
</tr>
<tr>
<td>Production period duration</td>
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<td>years</td>
</tr>
<tr>
<td>Wellbore length</td>
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<td>ft</td>
</tr>
<tr>
<td>HF half-length</td>
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<td>%</td>
</tr>
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<td>psi</td>
</tr>
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<td>md</td>
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<tr>
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<tr>
<td>Drilling base cost per well (vertical part)</td>
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<td>$</td>
</tr>
<tr>
<td>Drilling cost per grid block (horizontal part)</td>
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<td>Cost per length of HF stage</td>
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<td>Gas price</td>
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<td>$/mscf</td>
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<td>Base cost per HF stage</td>
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<td>OPEX per well</td>
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<td>$/day</td>
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Table 1–Parameters for shale gas model and the NPV function

Here, k is time index, K is the total number of time periods simulated [days], \( Q_g^k \) is gas production rate during time period k [mscf/day], \( r_g \) is gas price [$/mscf], \( Q_w^k \) is water production rate during time period k [bbl/day], \( r_w \) is cost of water disposal [$/bbl], \( O \) is operational cost of the well per day [$/day], \( \Delta t \) is duration of the kth time period [days], b is a discount rate [%/100/year], \( C_w \) is base cost of drilling the vertical part of the producer well [$], \( N_{HF} \) is the number of HF stages, \( C_{fb} \) is hydraulic fracturing base cost per stage [$], \( C_{fl} \) is the cost of HF stages per unit of length [$/ft], \( x_{length} \) is length of HF stage [feet], \( L_w \) is horizontal portion of the producer in gridblocks, and \( C_p \) is well penetration cost per gridblock [$].

To test the performance of our framework, we used an anisotropic shale gas model with some fixed averaged values for the key economic and reservoir parameters (Table 1).

The schematic in Fig. 1 presents the detailed optimization workflow with the GA engine. The integrated framework connects in seamless fashion ECLIPSE™ 300 simulator (version 2012.2) with an optimization code written in MATLAB.

**Accomplishments**

To apply our framework, we assume there is a homogeneous extra-low matrix permeability field. This allows us to partition the shale gas reservoir into several smaller reservoirs that can be drained with one horizontal well. Then we apply optimization to the smaller reservoir and obtain the total discounted NPV for the entire play by multiplying the NPV for the smaller reservoir by the number of horizontal wells. In addition to this, we assume symmetry in size, well length, HF stages locations and number in all smaller reservoirs (Fig. 2).

**Significance**

Our optimization framework gives the expert visual and quantitative aid as to how many HF stages to place based on the current economic situation, what the spacing and half-length of these stages should be, and what discounted revenue is expected from a particular project.
**Future Work**

Currently we are developing modification of the GA in order to accommodate multiple objectives via non-dominated sorting, which might include short- and long-term revenue or production.

**References and Related Publications**


ECLIPSE 300. ECLIPSE Technical description Version 2012.2.0.0


Abstract
This research showed the technical feasibility of replacing diesel for powering drilling and hydraulic fracturing operations in the Bakken formation with flared associated shale gas. We showed that this is a more efficient solution to powering drilling rigs and hydraulic fracturing equipment while also reducing the amount of gas being flared in shale oil and condensate plays producing associated gas. To do this, we investigated the composition and volumes of gas being flared and the average energy requirements for drilling rigs and hydraulic fracturing equipment in the Bakken area. The investigation revealed that the amount of associated shale gas being flared is more than enough to supply the energy required for power to the drilling rig and frac spreads. After reviewing power sources that can use natural gas (including turbines, dual-fuel, and dedicated spark ignited engines) and associated gas separation technologies, we were able to make recommendations for the best use of flared associated shale gas. We showed that making the switch to natural gas from diesel would result in cost savings for drilling rig and hydraulic fracturing operators. Natural gas costs less than diesel and is more environmentally friendly.

Objectives
Reported data indicated that the current amount of associated shale gas being flared in the Bakken and Eagle Ford shale areas is enough to power drilling and hydraulic fracturing in these areas. The objective of this research was to evaluate the technical feasibility of replacing diesel with natural gas in drilling and hydraulic fracturing operations.

Approach
First, we analyzed the composition and volumes of gas being flared in the Bakken shale area. Second, we collected data to understand the average energy requirements for drilling rigs and hydraulic fracturing equipment in the Bakken. Next, by dividing the amount of natural gas produced and flared by the amount of natural gas required for power, we established the economic capacity in which power can be supplied to run these operations. The feasibility of this concept was evaluated by comparing the economic capacity on a per well basis to the amount of drilling rig and frac treatments currently active in this formation.

Next, we explored the power sources, including dual-fuel and other forms of internal combustion engines, needed for the efficient use of natural gas for drilling and hydraulic fracturing. We collected information on the technical specifications (i.e., gas composition for optimal performance, load constraints, etc.) of various power sources able to use natural gas. In addition, we reviewed gas separation technologies designed for microscale gas processing by comparing and contrasting them.

Accomplishments
The Bakken currently produces about 400,000 Mcf/d of unmarketed gas. This unmarketed gas accounts for 40% of total production. During this term, we were able to determine the amount of unmarketed gas produced per day, and found the Bakken produces more than enough gas to support drilling rig and hydraulic fracturing treatment power for wells in this area. There is enough natural gas to complete 125 wells per day, if completing a well with drilling and a hydraulic fracturing treatment. With 9 wells on average being completed per day by these operations, the available associated gas produced is 15 times
greater than the amount that could be used at the current activity level, leading to a surplus of unmarketed gas that a market must be found for.

We described the various technologies currently available to allow wellhead gas to effectively power drilling rig and hydraulic fracturing treatments, along with the technical specifications at which they can operate for maximum efficient use of the unmarketed associated gas. Power sources such as spark ignited engines, dual fuel engines, hybrid power, and turbines are available to use natural gas as a fuel. Table 1 describes pricing estimates per drilling rig based upon the use of 2-3 engines per rig (Hill et al. 2011; Kulkarni 2013). For hybrid power, only one ultracapacitor would be needed with the use of 2-3 engines generating power (Juergens 2013).

When selecting various power technologies, one must not only consider the initial capital cost, but also the power capacity and performance he is looking to gain. Although dual fuel costs the least of all the natural gas power technologies, one still has to consider the cost for diesel fuel. Technologies such as SI engines and gas turbines cost the most, but running off 100% natural gas offers the maximum use of flared associated gas resulting in virtually $0 in fuel operational costs. Ultracapacitor hybrid power compensates in technical areas where SI engines and gas turbines cannot. Pricing may be on the higher end, but will allow gas turbines and engines to optimally operate with the maximum use of flared associated gas.

We also located several small scale gas processing technologies available that can process wellhead gas into pipeline quality liquified natural gas (LNG) and compressed natural gas (CNG) which can be used effectively in different types of natural gas fueled engines. SUPERCOOL™ is able to process associated wellhead gas and separate the CO₂ and the natural gas liquids, processing it into LNG. Another technology is GE’s CNG in a Box. This was originally designed to process pipeline gas for vehicular fueling stations, though an additional gas separation unit would need to be purchased to separate all unwanted components before condensing into CNG.

**Significance**

This project would be of great value for drilling rig operators. As mentioned previously, most drilling rigs use diesel fuel for power. Using natural gas for drilling rig power has many benefits. For one, natural gas costs less, provides positive environmental impact leading to reduced emissions and better air quality, and helps the United States to become more energy independent when compared to the use of diesel fuel. Since the U.S. has an abundance of natural gas resources, making the switch to use natural gas for power seems not only economical, but also environmentally conscientious.

**References and Related Publications**


Re-Use of Produced Waters as Hydraulic Fracturing Fluids

Abstract

Economic production from tight sand gas reservoirs usually involves multistage hydraulic fracturing. High costs of water acquisition and waste water disposal, and the lack of available water resources near operation sites, make the reuse of produced water an unavoidable option. However, recycling produced water in hydraulic fracturing jobs results in low quality fracturing fluids, which usually have high levels of hardness and salinity. This is especially true for flowback fluids, which contain high polymer loading. The rheological properties of fracturing fluids significantly affect leak-off rate, proppant placement, length and width of fractures, fracture conductivity, and, consequently, the success of the treatment.

This work is divided into three main sections. The objective of the first part is to determine the acceptable dissolved solid contents for flowback fluids to prepare fracturing fluids. A series of laboratory experiments were conducted on a high-pH borate crosslinked guar-based polymer to determine the effects of salt species on the prepared polymer, ranges of acceptable salts contents, and ability to transport the proppant. Dynamic rheological measurement tests, static proppant settling, and small-amplitude oscillation rheology were the methods used to evaluate prepared samples at low, medium, and high temperatures up to 305°F.

In the second part, the effect of salts and chelating agents on the proppant transport and rheological properties of the prepared fracturing fluids was examined in detail. The results help to determine which salts can affect the desirable expectation from the fracturing fluid and how to increase the limits further to be able to use the flowback fluids in future hydraulic fracturing jobs. The thermal stability and viscosity measurement tests were conducted at 140°F, 225°F, and 305°F and a pressure of 300 psi. The static settling tests were run at ambient temperature and 225°F.

Developing an advisory system is the final part of the project. Based on the provided information, the system determines the operative base fluid content range, the purifying and viscosifying method, and the amount of fresh water, if necessary. It will include suggested remedies and treatment for combinations entered, which would use the most common combinations and conditions reported in industry.

Objectives

Literature review indicated that the use of chemical treatment systems have recently received increased attention regarding the total dissolved solids (TDS). The overall goal of the project is to provide industry with viable options in the reuse of produced water. The main objective of this work can be divided into three sections:

» Investigation of the feasibility of using produced water in hydraulic fracturing stimulation in sandstone fields at reservoir temperature
» Introduction of new techniques to evaluate the flowback fluid and to purify/qualify produced water
» Reduction of high costs for water acquisition and produced water disposal

Approach

This work focuses on the analysis of the dissolved solid contents of produced water, which affects the application of flowback fluids and the capability of prepared fluids in proppant transport and handling. A series of laboratory experiments were conducted on a
Fig. 1–Single shear rate test to investigate the stability of proposed fluids at 140°, 225°, and 305°F; 170 s⁻¹; and 300 psi. The base fluids were gels prepared with 20, 30, and 50 pptg of polymer; 2 wt% EDTA, 16, 19, and 20 gpt buffer; and 1.0, 1.25 and 3.0 gpt crosslinker was selected as the base fluid at 140°, 225°, and 305°F, respectively. The gels without EDTA were prepared with 20, 35, and 50 pptg guar, 2.0, 4.0, and 4.0 gpt buffer, and 1.0, 1.0, and 3.0 gpt crosslinker loading at 140°, 225°, and 305°F, respectively.

This study sets forth the proppant transport and rheological properties of fracturing fluids as the main concerns to define the critical dissolved solid contents in the reuse of flowback fluid to help minimize water handling costs and footprints.

**Accomplishments**

**Thermal Stability at Bottomhole Temperatures**

In the viscosity measurements, the results showed that EDTA helped the fluid to tolerate high salinity, much higher than seawater, and build a very good viscosity over a wide range of shear rates. It is a good sign that this fluid can be a viable candidate for fracturing fluids, but it is not enough. The proposed fluid should display acceptable thermal stability over at least a two-hour single shear rate test at bottomhole temperature. High concentrations of divalent cations, such as calcium and magnesium, can increase the risk of fracturing fluid failure. The fluids were prepared with the same procedure and specifications. Fig. 1 illustrates the apparent viscosity over time. The experiments were run at a shear rate of 170 s⁻¹, temperatures 140°, 225°, and 305°F, and a pressure of 300 psi in all experiments. The power-law constants (n' and K) were measured every 15 minutes. All gels did not break over time and the recorded viscosities were very stable. The other part of the test was determining the lowest possible polymer loading. At 140° and 305°F, 20 and 50 pptg guar were the minimum polymer loadings, which show acceptable viscosities, respectively. However, EDTA enabled us to reduce the polymer loading from 35 to 30 pptg at 225°F. The gel loaded with 30 pptg guar and 2 wt% EDTA could build better viscosity than the one loaded with 35 pptg guar and no EDTA at 225°F.

High salinity can act as a breaker in post fracturing treatments (Fischer et al. 2001). However, high TDS in high pH crosslinked guar/borate systems causes several problems. The main issues are reduction in the hydration level, weak viscosity development, pH reduction, and interference with the crosslinking process. When all salts were added in the fluids, although KCl increased the ionic strength of the solution and the performance of the fluid improved, NaCl decreased the rate of dissolution of calcium and magnesium precipitations (Fredd and Fogler 1998).

**Static Settling Tests**

The static settling test is a simple but practical method which visually enables a comparison between proppant settling in different fluids. A fracturing fluid should be able to provide adequate transport of proppants in the fracture. The further the proppant moves inside the fracture and the higher its conductivity, the more successful the job. After the linear gel
was prepared, a 20/40-mesh Ottawa sand was added to the fluid before the crosslinking process. The proppant had a specific gravity of 2.65 and was added at a concentration of 4 lbm/gal. The fluid/proppant mixture was placed in a 100 ml graduated cylinder in a see-through cell that could be heated up to 450°F at a pressure of 500 psi. The level of proppant settlement through the fluid was recorded every 5 minutes for 200 minutes or until all of the proppant had settled to the bottom of the test chamber. This experiment would simulate near wellbore conditions where the shear rates are low.

The tests were also conducted at a temperature of 225°F. The samples needed 15 (± 5) minutes to reach the cell temperature. Fig. 2 confirms that increasing the polymer loading from 20 to 30 pptg at 225°F significantly increased the performance of both fluids. The base fluid was prepared with fresh water. The sample loaded with maximum salt concentrations and EDTA showed very good suspension, and 83% and 75% of the proppants remained in suspension after about 200 minutes, respectively.

![Fig. 2](image)

**Fig. 2**—Comparison between proppant settling of sample prepared with fresh water and the fluid prepared with the maximum acceptable dissolved solid contents which were loaded with 4 lbm/gal of 20/40 Ottawa sand at 225°F. The base fluid was a gel prepared with 20 pptg guar, 2 wt% EDTA, 19 gpt buffer, and 2.0 gpt crosslinker loading (left) and the other sample was a gel prepared with 30 pptg guar, 2 wt% EDTA, 19 gpt buffer, and 1.25 gpt crosslinker loading (right).

**Significance**

Little or no practical range for TDS limitation and chelating agent application have previously been specified in reusing flowback fluids. Furthermore, most of the reported successes have been based on specific jobs. Therefore, viscosity, rheology, and proppant transport of fracturing fluids were conducted in this study to achieve the main goals of this study. Chelating agent helped to increase the tolerability of the dominant cations concentrations in the base fluid, especially at high temperature and pH. An advisory system can make water treatment and reusing flowback fluids a more technically proven and practical practice, and can reduce the water handling costs.

**Future Work**

Developing an advisory system is recommended. It will include suggested remedies and treatment for combinations entered which would use the most common combinations and conditions reported in industry. The fuzzy logic system, consisting of several fuzzy logic evaluators, can be applied to study, evaluate, and determine the best systems to stimulate oil and gas production or water injectivity in wells. Based on the provided information, the system first determines the operative base fluid content range, purifying and viscosifying method, and the amount of fresh water if necessary. Secondly, the system chooses the best combinations of the possible fluids. The system then determines additives for the

(continued on next page)
fluid systems. At the same time, the system also checks the compatibility of the fluid and additives with formation fluids and composition. (The last part depends on availability of data.)

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