This issue of the Crisman newsletter contains brief descriptions of four on-going Crisman research projects and one non-Crisman project.

1. **In-situ Oil Upgrading Using Tetralin (C_{10}H_{12}) Hydrogen Donor and Fe(acac)\textsubscript{3} Catalyst at Steam Injection Pressure and Temperature**

2. **Investigation of Well Spacing and Completion Practices in Coalbed Methane Reservoirs**

3. **Drilling Through Gas Hydrate Formations**

4. **An Analysis of Pressure Buildup Effects on CO\textsubscript{2} Storage Capacity in Deep Saline Aquifers**

5. **Viscosities of Natural Gases at High Pressures and High Temperatures**

For more information on these and other Crisman projects, please visit our website at: [http://www.pe.tamu.edu/crisman/index.html](http://www.pe.tamu.edu/crisman/index.html) or contact one of the key investigators listed on the projects.
Introduction
In-situ upgrading enhances oil recovery, increases well production and lowers lifting and transportation costs from reservoir to refinery. It also eliminates the cost of building catalytic reactors or vessels, and can be applied onshore, offshore, or in remote locations where surface facilities may be problematic. In-situ upgrading can be applied on a well-to-well basis and can be adjusted for declining production rates, whereas surface processing is designed for a specified range of crude volume. Implementation of in-situ upgrading significantly reduces energy consumption and is more environmentally friendly, yielding lower quantities of byproducts that reduce disposal expenditure.

Objectives
The main objectives of the research are:
» Follow up on research started by Ahmad Mohammad, which is in-situ oil upgrading using tetralin (C\textsubscript{10}H\textsubscript{12}) and Fe(III) catalyst at steam injection pressure and temperature as found in the field.
» Make runs in which we inject a slug or slugs of tetralin/catalyst followed by steam injection.
» Simulate longer injection period in the experiments by making runs for several days, stopping at the end of each day.
» Make runs using a reactor cell and synthetic oil made of several pure components (similar to Ramirez’s PhD research). Analyze any change in synthetic oil composition by GC analysis. This type of experiment will help us understand which components are mostly upgraded by tetralin/catalyst – and then extrapolate results to actual oil.
» For both displacement and reactor cell experiments, investigate the effect of steam-surfactant injection to lower IFT and thus increase recovery factor.

Approach
For reactor cell experiments, one pure single component of synthetic oil will be used each time to study the upgrading effect for each component. The oil, water, tetralin and catalyst are mixed in the cell and then pressurized and heated to reservoir steam flooding conditions. Compositional analysis using a GC is then performed to evaluate degree of upgrading relative to each oil component.

For displacement experiments, the experimental set-up is made up of four main parts: injection cell, fluid injection system, fluid production system and data recording system (Fig. 1). The procedures are: (1) Prepare sand/water/oil mixture. (2) Tamp the mixture into the injection cell & pressure test, (3) Install the injection cell into the vacuum jacket & pressure test whole system, (4) Set heating jacket to reservoir temperature and leave overnight, (5) Condition steam generator and pressurize injection cell, (6) Start tetralin or tetralin-catalyst injections (only for injection runs), (7) Start steam injection and collect samples.

Accomplishments
» Investigated equipment requirements for research.
» Reviewed papers and books on oil upgrading using tetralin/catalyst.

Fig. 1–Schematic diagram of experimental set-up.

Project Information
1.3.21 Experimental Studies of Non-thermal EOR Methods for Heavy and Light Oil Recovery

Related Publications

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Zhiyong Zhang
Investigation of Well Spacing and Completion Practices in Coalbed Methane Reservoir

Objectives

» To develop realistic empirical descriptions of CBM reservoir properties (including cleat system interference)

» To develop an input data modification approach in the commercial reservoir simulation software based on invented analytical solutions

» To investigate well spacing and completion design practices under various development scenarios by using reservoir simulation

Accomplishments

» Literature search

» Production data analysis

» Start numerical simulation of slab model

Simulation result.

A simple model of the matrix-fracture system was developed by assuming a drainage in the matrix grid with fractures as boundaries. A low permeability and high porosity value was assigned in the matrix system, where high permeability and low porosity were associated with the fracture system (boundaries). The flow from the matrix to the fracture was specified as a constant rate. The reservoir was modeled in slabs geometry, n=1 means one parallel set of fractures, n=2 means two normal sets of fractures and n=3 means three normal sets of fracture. From the simulation results, a pseudo steady-state condition was achieved in a different time. The numerical analysis will be continued based on different models and focused in the transient flow period.

Future work

» Continue production data analysis

» Continue numerical simulation with emphasis in transient behavior of a different set of reservoir models

» Start analytical solution development for linear flow in a Coal Bed Methane Reservoir

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Project Information
1.4.4 Effects of Infill Drilling Coalbed-Methane Reservoirs

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Pahala D. Sinurat
Drilling Through Gas Hydrate Formations

Objectives

Modern petroleum industry meets highly complex technical challenges with increasing demand of operations in deepwater offshore and onshore arctic environments, where greater emphasis should be placed on quantifying the hazards to drilling operations caused by gas hydrates. As progress is aimed towards ultradeep waters, it becomes important for future drilling operations to be able to identify ahead of time when problems are likely to occur.

The objectives of this research are:
- to develop a numerical model for estimation of hydrate dissociation process when drilling through gas hydrates.
- to develop comprehensive risk management capability for drilling in gas hydrates.

Approach

The problem is divided into three “subproblems”. Hydrate dissociation possibility will initially be analyzed separately in drilled formation: at the bit and in the wellbore. The available field data will be gathered to assess heat transfer phenomena in reservoir and wellbore.

Significance

Only limited field data on drilling through hydrates are available at present. Because of heat transfer, dissociation of hydrates will lead to change in mechanical and petrophysical properties. Sediment study in a reservoir is very complicated, thus it needs to be discretized and a number of assumptions have to be made at this stage.

Fig. 1–Gas-hydrate related problems

Fig. 2–Radial heat transport from hot drilling fluid in wellbore into the formation (J. Yang)

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Project Information
1.5.5 Design of Fluids for Drilling Through Hydrates

Related Publications
Peterson J. Computing the Danger of Hydrate Formation using a Modified Dynamic Kick Simulator. Presented at the 2005 Asia Pacific Oil and Gas Conference, Jakarta, Indonesia, 5-7 April.


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May 2009
An Analysis of Pressure Buildup Effects on CO₂ Storage Capacity in Deep Saline Aquifers

Objectives
Pressure behavior in CO₂ storage aquifers has been neglected thus far in literature because prior modeling work has assumed that the target aquifer for CO₂ storage either has infinite capacity or has a constant pressure boundary, and that injected CO₂ will displace the water in the pore space. Clearly no aquifer actually has infinite capacity. An aquifer with a constant pressure boundary is termed “open,” because it opens either to the atmosphere via a surface outcrop or to the seafloor. Because CO₂ injected into an open aquifer could migrate to the atmosphere directly or via the connected water body, closed systems should be the choice for CO₂ containment. However, in closed aquifers the capacity for CO₂ storage will be significantly less than for an open aquifer because brine displaced by injected CO₂ cannot escape the system. The pore space of the rock is already filled with water and any additional injection of CO₂ into the system will lead to an increase in the overall reservoir pressure. The objective of this research is to spell out that in reality, a closed aquifer will have significant pressure response during injection, and pressure build-up could pose significant limits to the amount of CO₂ that can be sequestered.

Approach
This research utilizes pressure transient testing and numerical reservoir simulation as a tool to generate and validate the results. This work provides models for both injection falloff and multiwell and multilayer interference analysis. The models show the expected features in the transient responses, and, in particular, indicate what behavior may signal a CO₂ leak through a conductive fault, through a leaky formation bed boundary, or through a cement leak in an existing well. The second part of this study evaluates an active reservoir engineering technique to accelerate dissolution and residual trapping of CO₂ in a closed reservoir system. By drilling a brine injector on one side and a brine producer on opposite sides of a CO₂ injection well, the CO₂ is injected into a flowing brine stream where its contact with brine is enhanced. The controlled injection of CO₂ with this technique reduces the uncertainty about the long-term fate of the injected CO₂, prevents CO₂ from migrating toward potential outlets or sensitive areas; and increases the volume of CO₂ that can be stored in a closed aquifer volume. The value of this approach to CO₂ storage capacity is comparable and analogous to the value of pattern well water flooding to oil recovery. Analytical techniques provide simple and quick estimates of the amount of CO₂ that can be sequestered in a particular formation.

Significance
This work provides models for both injection falloff testing and multiwell and multilayer interference analysis that can be used for aquifer characterization and, in particular, for leak detection. The controlled injection of CO₂ with this technique reduces the uncertainty about the long-term fate of the injected CO₂; prevents CO₂ from migrating toward potential outlets or sensitive areas; and increases the volume of CO₂ that can be stored in a closed aquifer volume. The value of this approach to CO₂ storage capacity is significantly greater than the base case scenario with only CO₂ injection in the reservoir.

Residually trapped CO₂ distribution in the reservoir due to control injection-extraction technique. The amount of CO₂ trapped is significantly greater than the base case scenario with only CO₂ injection in the reservoir.

Project Information
Coupled Fluid Flow and Reservoir Geomechanics Using Streamlines

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Abhishek Anchilya
Viscosities of Natural Gases at High Pressures and High Temperatures

Introduction
Gas viscosity is one of the gas properties that is vital to petroleum engineering. Its role in the oil and gas production and transportation is indicated by its contribution in the resistance to the flow of a fluid. Gas viscosity is also necessary for drilling fluid design and well control, and is a key element that controls the recovery factor of reserve in place or flooding sweep efficiency in gas injection.

Although gas viscosity at low to intermediate pressure and temperature has been studied intensively and thoroughly understood, gas viscosity at high pressures and high temperatures (HPHT) is still a knowledge gap in oil industry. As we go deeper and deeper into formations, the hydrocarbon we encounter is more gas than oil due to the chemical reaction causing oil transfer to gas when the temperature increases, thus our chance to play with gas at HPHT climbs drastically. Since gas viscosity dictates the fluid flow from reservoir into the wellbore, according to Darcy’s law, and it affects the friction pressure drop for fluid flow from bottomhole to the wellhead, we need gas viscosity to optimize the production rate for production systems, even at HPHT.

Objectives
The initial objective of this project is measuring the viscosities of gases at HPHT in the laboratory. We can then correlate the available high temperature and high pressure gas viscosity data with pressure and temperature using regression procedures. Finally a correlation that can be used to predict viscosity as a function of composition, pressure, and temperature will be constructed for HPHT conditions.

Our objectives are to:
» Measure the viscosity of four naturally occurring hydrocarbon gases at various pressures and temperatures, with emphasis on high pressures and temperatures.
» Use the measured viscosities to check and extend an existing correlation proposed by Lee et al.
» Use gas compressibility factors to check and extend the gas compressibility correlation equation proposed by Piper et al.
» Develop a new correlation to predict viscosity as a function of composition, pressure, and temperature.

Approach
In this research, a modified falling body viscometer is used to measure gas viscosity at HPHT. The version we use is a Cambridge Viscosity SPL440 viscometer. It is designed by Cambridge Viscosity, Inc. exclusively for measuring viscosities of petroleum fluids, oils and gases. The measurable range of the gas viscosity is from 0.02 to 0.2 cP. The accuracy of the VISCOvpt is reported to be around 1% of full scale of range. Its operating pressure and temperature are up to 25,000 psi and 400°F, respectively.

The principle of modified Falling Body Viscometer
The Cambridge VISCOvpt works on the principle of a known piston traversing back and forth in a measuring chamber containing the fluid sample. The piston is driven magnetically by two coils located at opposite ends. The time taken by the piston to complete one motion is correlated to the viscosity of the fluid in the measuring chamber by a proprietary equation.

Problems needing to be solved
The manufacturer did not provide the proprietary equation. We will investigate into this measuring theory to construct the relationship between piston traveling time and gas viscosity, because if we do not know the correlation in this black box, we will not be confident with our measured viscosity. Before the measurement of gas viscosity, calibration of low end and high end viscosities needs to be performed to make sure the viscometer is ready for measurement.
Viscosities of Natural Gases at High Pressures and High Temperatures (continued)

One of the problems we need to solve is the pressure and temperature calibration. The low and high end calibration viscosity cannot cover the whole range of the experiment we are going to perform. How the pressures and temperatures outside of the calibration viscosities affect the measured viscosity is still unclear.

The measured viscosity reading directly from the viscometer is not the true gas viscosity. Correlation that incorporates gas composition, pressure, and temperature needs to be used for transferring reading viscosity to true gas viscosity. Different types of gas are used to measure viscosity at various pressures and temperatures, therefore one of our goals in this research is to derive this correlation so it can be used as an extension of current correlation for low to intermediate pressure and temperature.

Experiment procedure
Viscosity of nitrogen at HPHT is measured first since it is much safer than air or natural gas. Then methane and air viscosity will be measured in the coming experiments. All of these measured data will be compared with the available data from other investigators to check the consistency. Even though data at HPHT may not be available from other investigators, data at intermediate pressure and temperature can be used as calibration data.

Accomplishments
In December 2008, we finished the experiment on nitrogen viscosity, therefore we moved to the second stage, i.e., measuring methane viscosity. Before measuring methane viscosity, it was necessary to clean the viscometer, and then convert the whole system from nitrogen to methane.

In January 2009, we disassembled the facility and cleaned the viscometer. To make sure that the viscometer can reproduce the same result as before, one more experiment on nitrogen viscosity was run with a temperature of 152°F. Analysis of this experiment showed that the reproducibility of the viscometer is perfect after the maintenance (Fig. 1). Previous deviation of the viscosity at low pressure was due to toluene, which was used to clean the cell and piston. It was clear that, as experiment carried on, the effect of toluene went away (Fig. 2). Thus we began the experiment on methane viscosity.

Data analysis of experiments on nitrogen viscosity at temperature of 170°F at the 3rd Run are agreeing with those in the 2nd Run.

Future work
» Measure methane viscosity.
» Analyze finished experiment data (Nitrogen Viscosity).

Reproducibility test compares with test in the 3rd Run (T77)

![Fig 1.-Comparison of Reproducibility Test with Test 77](image1)

![Fig 2.-Effect of Toluene on Nitrogen Viscosity in the Reproducibility Test](image2)