October Newsletter

Issue 9, October 2010

Crisman Week is Coming to College Station

Crisman Week will be held December 7, 8 and 9, 2010, and will be hosted by the TAMU Department of Petroleum Engineering in College Station, Texas. Over the course of these three days, the results from the research in 2010 will be explained in numerous presentations and posters.

December 7: Heavy Oil Recovery, Well Construction, and Well Stimulation

The meeting on December 7 will start with Heavy Oil Recovery. Presentations on experimental studies of non-thermal EOR methods; hybrid steam-solvent injections to increase efficiency; the artificial geothermal energy potential of steam-flooded heavy oil reservoirs; and combustion assisted gravity drainage using a horizontal injector-producer pair will be given.

The meeting will then shift focus to Well Construction, with emphases on reservoir compaction and casing integrity in the Gulf of Mexico and the experimental study of high pressure, high temperature well cementing failure and fatigue.

Well Stimulation will round out the day. Presentations will be given on hydraulically fractured well performance in high rate wells; reaction of organic acids with calcite; quantitative analysis of amphoteric surfactants; viscosity of polymer-based in-situ gelled acids during well stimulation; and the cleanup of drilling mud filter cake.

December 8: Shale Gas, shale Gas Water Issues, and Environmental, CO_2

The December 8 meeting will begin with Shale Gas presentations on issues such as shale gas reserves estimation; the New Albany shale gas project; modeling shale gas reservoir performance; and transport properties characterization of tight gas shales.

The meeting will then address Shale Gas Water Issues with presentations on low impact O&G activity; fracture fluid re-use and optimization; the re-use of produced waters and hydraulic fracture fluid; and the characterization and simulation of discrete fracture networks.

The Environmental, CO_2 topic at the end of the meeting will feature three presentations on CO_2 sequestration.

December 9: Tight Gas

The meeting on December 9 is dedicated to Tight Gas. The presentations given this day will touch on many subjects: continued development of an unconventional resources advisor; advanced hydraulic fracturing technology for unconventional tight gas reservoirs; permeability determination from diagnostic fluid injection tests; application of adaptive gridding and upscaling for improved tight gas reservoir simulation; integrated reservoir and decision modeling to optimize development of unconventional gas reservoirs; stochastic history

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matching, forecasting, and production with the ensemble Kalman filter; viscosities of natural gases at high pressures and high temperatures; and transient multiphase sand transport in horizontal wells.

Posters

Some posters will be displayed which reflect the topics of the five new research projects funded this year: fracture modeling and flow behavior in shale gas reservoirs using discrete fracture networks; minimizing water production from unconventional gas wells; multiple fluid phases across a shale gas basin—Eagle Ford; rapid, probabilistic reserves estimation for fractured horizontal wells in shale gas reservoirs; and re-use of produced waters and hydraulic fracture fluids. Other posters presented will discuss other research, such as fracture network propagation models and enhanced heavy oil recovery with emulsion flooding.

For a complete agenda of the three-day Crisman Week, please go to the Crisman Institute website's upcoming events page.

Crisman Research Presented at the Canadian Unconventional Resources and International Petroleum Conference in Calgary, Canada

Weiqiang Li presented five papers at the Canadian Unconventional Resources and International Petroleum Conference in Calgary, Canada (October 19-21):

1. **Experimental Study of Solvent-Based Emulsion Injection to Enhance Heavy Oil Recovery in Alaska North Slope Area** , SPE 136758, by Qiu Fangda and Daulat Mamora.

   This research presents the second stage experimental results of the Chemical EOR applications in a cold Heavy Oil reservoir. It mainly focused on verifying the solvent-based emulsion flooding mechanism in Heavy Oil reservoirs proposed in SPE-134613. It also discusses some key performance indexes in the whole experiments, like the injection schedule and permeability difference, etc. It also addresses the important role of nanoparticles in improving rheology behavior of the injected chemical solution.

2. **A Comparative Simulation Study of Addition of Solvents to Steam in SAGD Process**, SPE 138170, by Mojtaba Ardali and Daulat Mamora.

   This paper investigates the effect of co-injections of a variety of potential hydrocarbon additives to steam on the performance of steam assisted gravity drainage (SAGD). Propane, Butane, Pentane, Hexane and Heptane with different proportions from 1% to 20% by weight have been co-injected with the steam into two different types of Canadian heavy oil reservoirs: Athabasca and Cold Lake. The simulations were carried out in the absence and presence of initial solution gas to find out the effect of solution gas on the performance of SAGD and solvent-assisted SAGD processes.

   Simulation results show that solvents heavier than butane are considered suitable candidates for the Athabasca reservoir type, and that butane gave better results in the Cold Lake type reservoir under the operating conditions of this study. In addition, it was found the presence of high initial solution gas reduces the performance of SAGD and solvent-assisted SAGD processes.

3. **Combustion-Assisted Gravity Drainage (CAGD) Appears Promising**, SPE 135821, by Hamid Rahnema and Daulat Mamora.

   Combustion assisted gravity drainage (CAGD) is a new proposed thermal recovery process of heavy oil. It consists of dual horizontal wells for injection of air and production of mobilized oil. The CAGD well configuration is similar to SAGD in that an important feature of this technique is that the properly oriented dual horizontal wells aid the development of a combustion chamber and stabilized growth of the combustion front in the reservoir. In this study, potential application of this process is investigated using an advanced thermal simulator. Using the proposed kinetic model for Athabasca heavy oil (Belgrave et al. 1993), the field scale numerical simulation of SAGD, THAI, and CAGD has been conducted and their performance has been evaluated in terms of oil production rate and cumulative energy-to-oil ratio. Simulation results indicate that the CAGD process has the lowest cumulative energy-to-oil ratio while having an oil production rate as high as SAGD. In addition, results show increasing the air injection rate will improve gas circulate inside the chamber and remove flue gases out of the reservoir. Moreover, the THAI process shows the lowest oil production rate in comparison to the other two methods. This research identifies CAGD as a potential alternative to the ISC method.

4. **The Potential Applications in Heavy Oil EOR with the Nanoparticle and Surfactant Stabilized Solvent-Based Emulsion**, SPE 134613, by Qiu Fangda and Daulat Mamora.

   This paper presents the first stage experimental results of the Chemical EOR applications in a cold Heavy Oil reservoir. It mainly focuses on the investigation of the novel emulsion

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properties. The bench tests, such as a rheology study, a phase behavior scan, and an emulsion structure microscopic analysis, were performed. The modification of the emulsion rheology behavior by adding nanoparticles is also discussed in detail. Finally, the optimum emulsion composition screened by the proposed method is demonstrated, which is ready to be used in the core flooding research to follow.

5. **SWACO2 and WACO2 Efficiency Improvement in Carbonate Cores by Lowering Water Salinity**, SPE 137548, by A.A. Aleidan and D.D. Mamora:

In this paper, we have conducted reservoir condition coreflood experiments of different CO_2 injection modes to study the effect on oil recovery when altering the associated water salinity, hence altering CO_2 solubility in water. We considered CGI, WAG, SWAG, and waterflood. The results show that extra oil is contacted by the CO_2-water mixture behind the displacement front when water was injected either simultaneously or in alternating cycles with CO_2. When the CO_2 solubility increases in the lower salinity water, further improvement in the ultimate oil recovery was realized. The increase of CO_2 solubility in water has been considered a loss in CO_2, where it cannot be available to contact oil. However, the results of this experimental study indicate otherwise. For this carbonate rock, CGI has resulted in dispersive bypassing which lowered oil recovery. Therefore, when $WACO_2$ and $SWACO_2$ injections were implemented at all salinity levels, an increase in recovery was realized with significant reduction in CO_2 requirement. This indicates that the CO_2-water mixture that follows the CO_2 slug at the displacement front was successful in contacting the bypassed oil after the CO_2. Therefore, an increase in CO_2 dissolved in water made this mixture more effective in increasing oil recovery.

Yao Tian also presented a paper in Calgary:

1. **Barnett Shale (Mississippian), Fort Worth Basin, Texas: Regional Variations in Gas and Oil Production and Reservoir Properties**, SPE 137766, by Yao Tian and Walter Ayers.

This study lends insights into reservoir controls on well performance and should assist operators with optimization of development strategies and gas recovery. The approach used in this study may be applicable to other developing shale gas plays, such as the Marcellus and Haynesville Shales.

Artificial Geothermal Energy Potential of Steam-Flooded Heavy Oil Reservoirs

1.3.19 Harnessing the Geothermal Energy Potential of Heavy Oil Reserves

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Introduction

This study presents the concept of harnessing geothermal energy from heavy oil fields that have undergone steam-flooding and so have accumulated substantial heat from steam injection. Once the steam-flooding process reaches economic cut-off, due to high water cut and/or high steam-to-oil ratio (SOR), the reservoir would be abandoned, leaving behind stored energy in the form of heat. From this point, the reservoir could be regarded as an artificial geothermal system, and its intrinsic heat recovered by water circulation.

Objectives/Approach

The concept of harnessing geothermal energy from heavy oil reservoirs that have undergone steamflooding as proposed by Teodoriu et al. (2007) is presented. Once the steamflooding process reaches economic cutoff, resulting from high water cut and/or high SOR, the reservoir would be abandoned, leaving behind stored energy in the form of heat. From this point, a heat recovery process could be initiated, using water recirculation, as shown in **Fig. 1**. Relatively cold water is used as a carrier; it is injected from surface into the heated reservoir, it travels toward a production well, and is then recovered to surface after capturing the heat trapped in the rock. State-of-the-art technology for heat-to-electricity conversion, which is already used in the industry to recover waste energy, complements the process for generating power from the recovered heat. With this technology, the produced fluid heats up a working fluid that vaporizes and activates a turbine which generates electricity. Any residual oil still co-produced with the circulation water is separated prior to water re-injection.

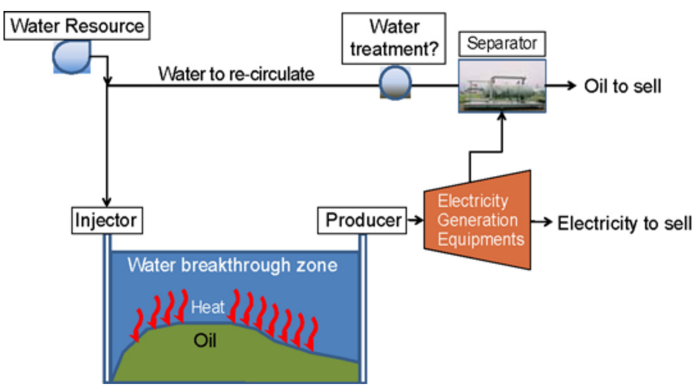

Fig. 1. Heat recovery scheme for electric power generation.

We use a compositional, thermal simulator to model the overall heat transfer efficiency throughout the reservoir. The Fourth SPE Comparative Solution Project (problem 3) - complemented by parameters obtained from well-known analogue fields - was adopted to build the base case scenario. The output from reservoir simulation is then coupled with a semi-analytical computation of heat exchange between the wellbore and the surrounding formation to estimate the total surface heat recovery. Depending on the arrival fluid temperature, heat could be used for either direct heating or electricity generation. Finally, a comparison of the power consumption and power generation is used to verify the feasibility of this concept.

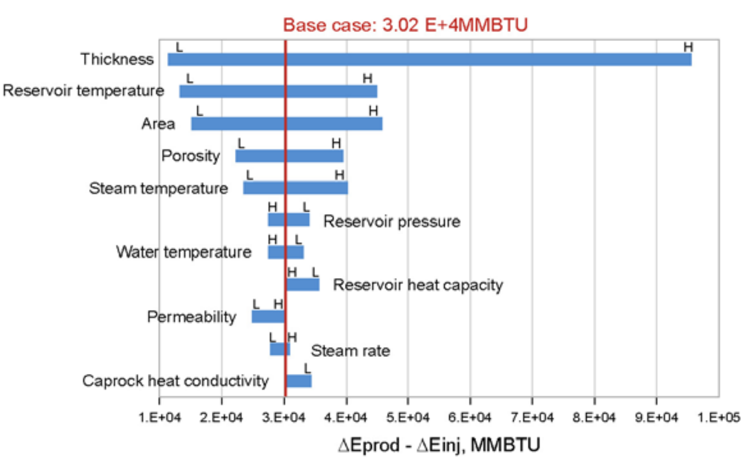

Fig. 2. Results of the sensitivity analysis.

Accomplishments

The amount of heat recovered by water circulation after steamflooding could be used to add value to heavy oil projects by implementing state-of-the-art technology to generate electricity from low-enthalpy resources. The results from reservoir simulations, semi-analytical wellbore calculations and an evaluation of the power requirements and performance of downhole and surface equipment show that the heated fluid recovered from one quarter of an inverted five-spot pattern (based on the fourth SPE comparative solution, problem 3) could generate net power of 3 kW for 3,800 days. For quantification of the power at the full field scale, these results would have to be multiplied by 100 (assuming 100 patterns in the field). The preliminary results would suggest the feasibility

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of the proposed concept of harvesting the artificial geothermal energy potential of steamflooded heavy oil reservoirs.

A sensitivity analysis carried out on the reservoir throughput assessed that the net energy recovery is primarily driven by the time available for heat storage in the reservoir during steamflooding and by the original reservoir in-situ energy (**Fig. 2**).

Starting from these preliminary results, the value of the heat recovery project could be commercially improved by accounting for the potential tax credits associated with promoting clean energy generation. This could justify greater investments during the oil-production phase of the overall project.

Acid Hydrolysis of Carboxybetaine Visco-Elastic Surfactant

2.5.16 Quantitative Analysis of Amphoteric Surfactant

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Objectives

Visco-elastic surfactants (VES) are recognized by their unique ability to form gel in-situ, and thus have been widely applied in acid diverting and fracturing treatments. Several types of VES have been used, including carboxybetaine surfactants. However, when mixed with hydrochloric acid under high temperatures, this particular type of VES is subjected to acid hydrolysis and may lose its visco-elastic property.

The objective of this study is to examine the impact of acid hydrolysis of carboxybetaine surfactants on their performance in various field applications.

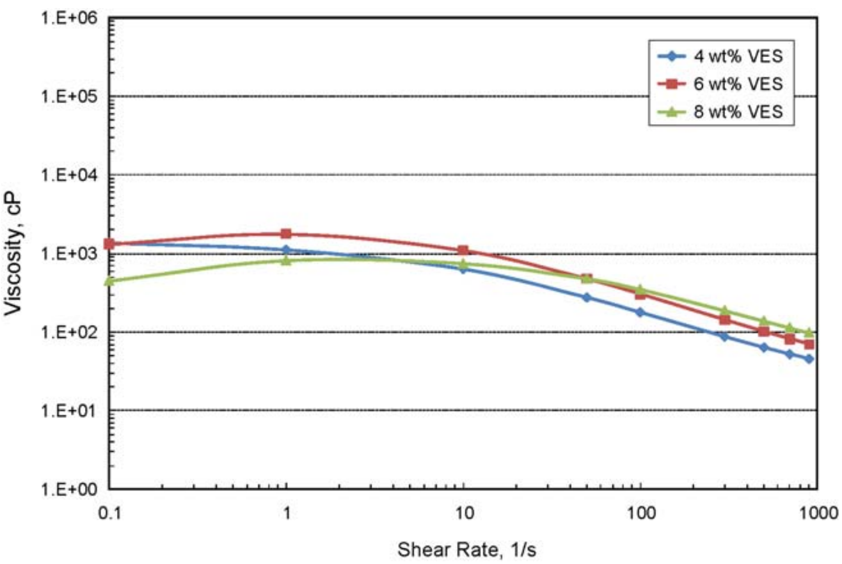

Fig. 1. HCl concentration: 15 wt%; surfactant concentration: 4. wt%, 6 wt% and 8 wt%; hydrolysis time: 0 hour (no hydrolysis).

Approach

In field applications, the reaction rate of surfactant acid hydrolysis is crucial in determining the suitability of pumping aged surfactant-based acids, and in understanding the viscosity evolution of surfactant-based acids downhole. In the present study, kinetics of acid hydrolysis of surfactant was investigated based on temperature, acid concentration, surfactant concentration and hydrolysis time. Hydrolysis temperature ranged from 120° to 250°F, acid concentration varied 4-20 wt% and surfactant concentration was 4-10 wt%. Samples were hydrolyzed for different periods of time, varying from 0.5 to 12 hours. Acid in hydrolyzed samples was spent by CaCO3, and viscosity of spent acid was measured as a function of shear rate using a high temperature/high pressure (HT/HP) viscometer. Hydrolysis products were given by gas chromatography/mass spectroscopy (GC/MS). Product concentration was analyzed by high performance liquid chromatography (HPLC).

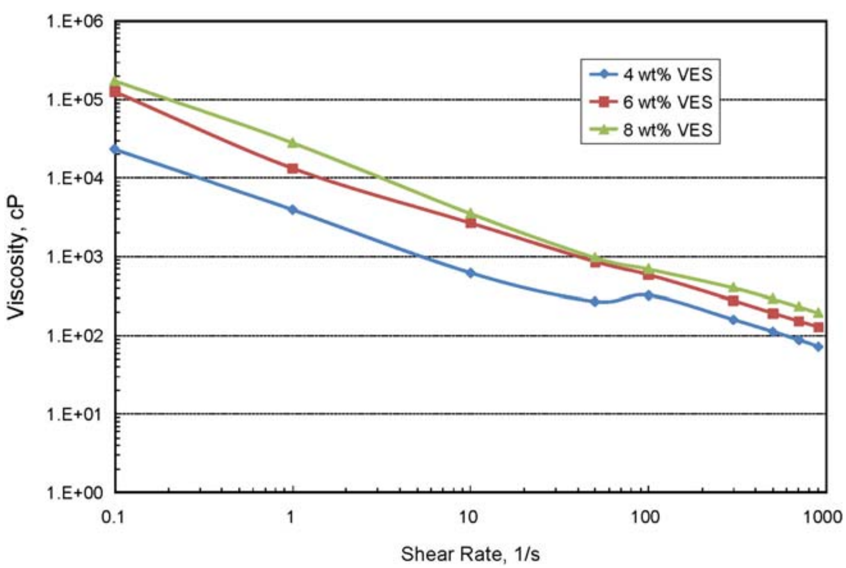

Fig. 2. Temperature: 190°F; HCl concentration: 15 wt%; surfactant concentration: 4 wt%, 6 wt% and 8 wt%; hydrolysis time: 1 hour.

Accomplishment

It was found the acid hydrolysis of carboxybetaine produced a fatty acid, and the reaction rate increased with temperature and the concentration of reactants. After 1-2 hours of hydrolysis at 190°F, viscosity of hydrolyzed and spent samples increased dramatically compared to unhydrolyzed samples; however, samples lost their viscosity after 3 hours of hydrolysis (**Figs. 1-3**). Moreover, owing to the generation of highly hydrophobic species from the hydrolysis

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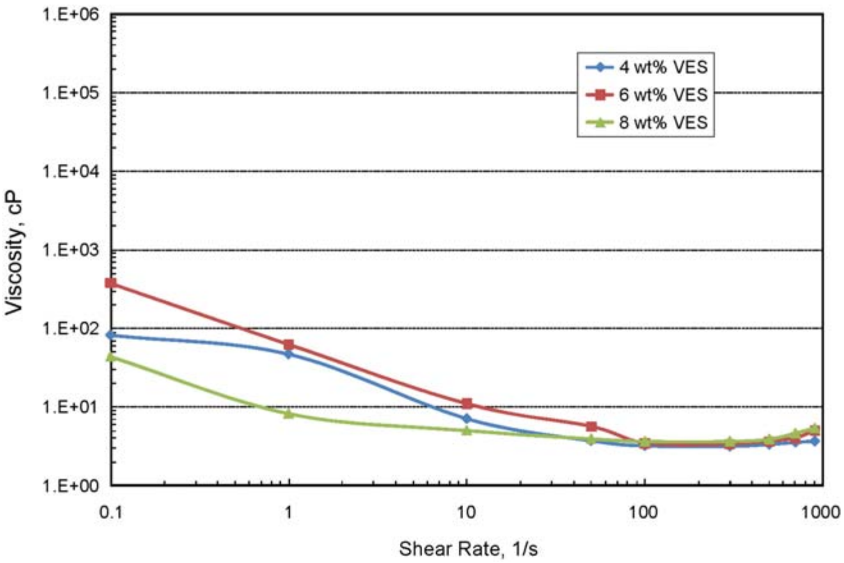

Fig. 3. Temperature: 190°F; HCl concentration: 15 wt%; surfactant concentration: 4 wt%, 6 wt% and 8 wt%; hydrolysis time: 6 hours.

reaction, an oily phase was separated from aqueous phase in hydrolyzed samples.

Significance

These observations indicated that, on one hand, acid hydrolysis of surfactants may lead to fluid viscosity reduction. Furthermore, it may cause formation damage due to phase separation. On the other hand, acid hydrolysis of surfactants helps short-time viscosity build-up which is in favor of acid diverting treatment. More importantly, it also aids in breaking down the gel, and thus is beneficial for gel clean-up if the treatment was carefully designed. In this case, no additional breaker is needed. This paper will discuss factors that affect acid hydrolysis of carboxybetaine surfactants, and give recommendations on how to utilize acid hydrolysis of surfactant-based acid in the field to avoid viscosity reduction and enhance gel clean-up efficiency.

For more information on other research projects, please visit the Crisman website: http://www.pe.tamu.edu/crisman/

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