Enhanced Oil Recovery and CO_2 Flooding/Sequestration in Carbonates

The University of Kansas Tertiary Oil Recovery Project (TORP) has an extensive portfolio of research on improving oil recovery from carbonate reservoirs. Staffing in TORP is funded by the State of Kansas. Students and faculty in the Department of Chemical and Petroleum Engineering, and Department of Geology interact extensively in their courses, learning skills directly applicable to the oil and gas industry. Engineering staff of TORP and faculty in Chemical and Petroleum Engineering specialize in dual porosity/fractured reservoir systems in carbonates. Interdisciplinary studies among TORP, Chemical and Petroleum Engineering, the Department of Geology, and KGS are exploring a wide range of avenues related to enhance oil recovery and CO_2 sequestration in carbonates. Examples of some current and pending projects include:

Seismic Imaging of CO_2 EOR in the Mississippian Reservoir, South-Central Kansas

George Tsoflias, Lauren Haga, Lynn Watney

SUBSURFACE APPLICATION: Assessment of seismic monitoring of a CO_2 injection in the Mississippian for enhanced oil recovery
STATUS: Long-term project in progress
TIMING: Significant results to be reported to membership (year 3 of 4)
FUNDING: Partial from United States Department of Energy

Purpose

Carbonate reservoirs are heterogeneous and the distribution of properties controlling the flow of fluids is difficult to predict. Seismic characterization of carbonate reservoirs is challenging and the subject of extensive research. Work reported by KICC at Wellington field in south-central Kansas identified characteristic relationships between Mississippian reservoir properties (thickness, porosity, fracture density and orientation) and seismic attributes (Amplitude Variation with Offset – AVO, P- and S-Impedance, seismic anisotropy - AVAZ), and developed seismic inverse workflows that predicted Mississippian properties. The proposed project extends prior work by evaluating the effectiveness of seismic imaging for monitoring CO_2 enhanced oil recovery (EOR) in the Mississippian reservoir at Wellington field.

Project Description

Time-lapse seismic analysis will be used to assess the effectiveness of seismic imaging methods (pre- and post-stack) for monitoring a CO_2 injection for EOR in the Mississippian. Seismic imaging pore fluid change in carbonate rocks is a challenging problem due to the stiff reservoir matrix masking the effects of fluid variability. However, previous work at Wellington field using pre-stack methods (AVO/AVAZ and impedance inversion) was able to map successfully porosity and fracture distribution in the Mississippian reservoir.

Background (baseline) seismic data acquired in 2010 will be compared to a 2D seismic line acquired over the CO_2 injection well KGS #2-32. The new seismic data was acquired in June 2016, following the completion of the CO_2 injection. The migration of CO2 within the Mississippian has been tracked in monitoring wells providing control points for the seismic analysis. CO_2 fluid substitution seismic modeling will examine two models, Gassman and Patch saturation (Adam et al., 2006; Misaghi et al., 2010; Vega et al., 2007). Preliminary modeling in the Mississippian predicts 15% change in zero-offset (stacked seismic) reflectivity. Modeling of pre-stack seismic predicts reflectivity change up to 45% introduced by the presence of CO_2 in the pore space (figure 1). Preliminary analysis of the new 2D stacked seismic line is inconclusive due to small reflectivity change (predicted up to 15%) masked by noise. The proposed work will employ pre-stack domain AVO analysis (Amplitude Variation with Offset) and impedance inversion in order to determine if seismic reflection imaged the CO_2 plume in the Mississippian.

Key Findings

- Comparison of Gassmann vs. Patchy substitution models show differing seismic responses. The true response of the Mississippian reservoir likely lies between these two end members
- Synthetic seismic models generated at wells KGS 1-32, 2-32 and 1-28 show very good agreement to observed seismic
- Post-stack time-lapse seismic data comparison is inconclusive due to relatively small (15%) reflectivity change

Deliverables

i) Comprehensive assessment of seismic methods (pre- and post-stack) for monitoring CO_2 injection in the Mississippian reservoir

ii) Development of seismic workflows for imaging pore-fluid changes and assessing EOR operations in the Mississippian

References

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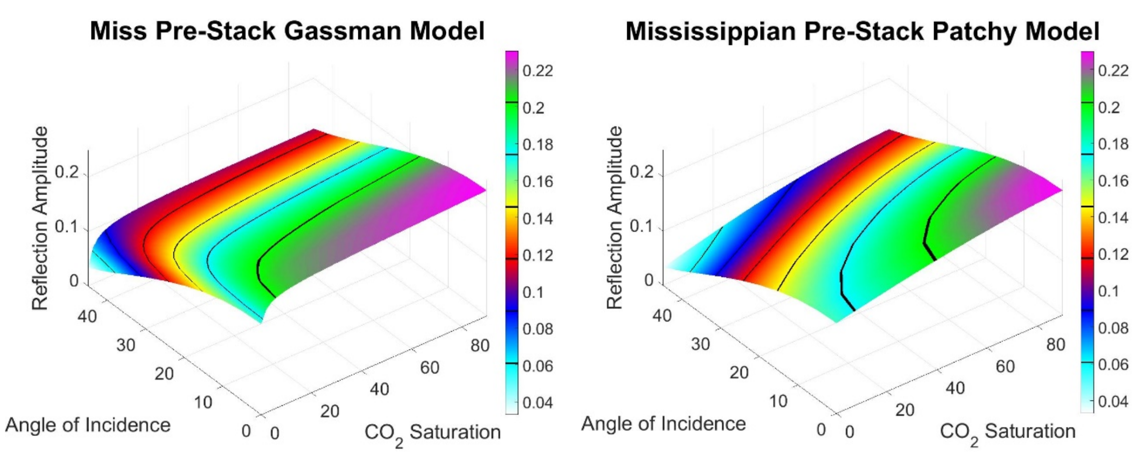

__Figure 1.__ Pre-stack fluid substitution models of the Mississippian reservoir at Wellington Field. The plots show the modeled amplitude with respect to CO_2 saturation and angle of incidence. The black lines are amplitude contours.

Determination of Wormhole Geometry during Acidizing in Carbonates Using an Improved Semi-Empirical Model

Xiaoli (Laura) Li and Gang Yang

SUBSURFACE APPLICATION: Mississippian limestone in Kansas and Oklahoma, Arbuckle, Grayburg/ San Andres of Permian Basin, Smackover, and Arab
STATUS: Project Proposed
TIMING: To be completed in the future if funded
FUNDING: Seeking funding

Purpose

The objective of this project is to develop a pragmatic tool for determining the wormhole geometry after the acidizing of carbonates. Such an innovative tool is anticipated to be applicable under various conditions associated with petrophysical heterogeneity and operational parameters (e.g., acid injection rate and acid concentration).

Project Description

The matrix acidizing has been extensively used to stimulate the development of carbonate reservoirs characterized by strong heterogeneity and poor connectivity. A highly conductive channel, also called wormhole, can be created from the reaction of acids and carbonates. Since a longer wormhole contributes more production from carbonate, numerous efforts have been made to optimize the operational parameters for achieving the maximum wormhole efficiency. In addition to conventional acid types, formation types, and injection rate, more details impacting the wormhole propagation have been investigated. Shukla et al. (2006) stated that an immiscible phase (i.e., oil or gas) can reduce the fluid loss from the main wormholes, thus allowing for deeper penetration of wormholes with a given acid volume. Considering the generation of CO_2 from the reaction of acid and carbonate, Cheng et al. (2016) demonstrated that the gaseous CO_2 can retard the wormhole propagation efficiency dramatically when a low injection rate is applied.

Those experiments are mainly focusing on the optimization of the acid volume to breakthrough (PV_{bt}) which guarantees a maximized wormhole efficiency; however, the importance of the induced wormhole geometry has been neglected to a certain degree. It is worthy to note that the dominant wormhole is preferred among four wormhole types (i.e., face dissolution, conical wormhole, dominant wormhole, and ramified wormhole proposed by Hoefner and Fogler, 1989) since it contributes the most improvement of the production, implying that the wormhole geometry has a significant impact on the production performance. Moreover, the accurate quantification of the wormhole geometry would benefit the matrix acidizing design at both the lab-scale and field-scale, provided that the relationship between the production performance and the wormhole geometry is clarified.

In the acidizing experiments, the wormhole geometry can be visually observed by integrating all digital slices of the acidized core samples obtained from a computed tomography (CT) scan. Figure 1 shows the typical geometry of the dominant wormhole observed in the laboratory. Although CT scan provides the wormhole geometry in a visual way, most of the publications only pay attention to the wormhole length while the wormhole width is rarely studied. It can be found from Figure 1 that the wormhole geometry cannot be accurately determined if only the wormhole length is available since the wormhole width is distinctly different at the head and end of the wormhole.

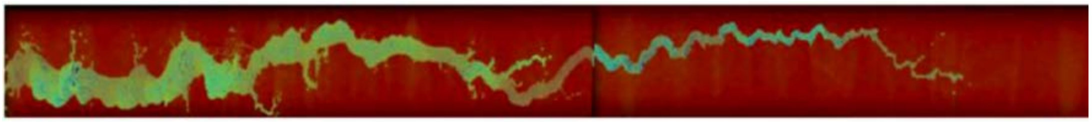

Figure 1. *A CT scanned wormhole (Qui et al., 2014)*

Considering the fluid loss from wormholes to the matrix, we propose to develop a model to accurately quantify the wormhole geometry based on the material balance and a semi-empirical model proposed by Buijse and Glasbergen (2005). Such a semi-empirical model defines the wormhole growth rate (V_{wh}) and the PV_{bt} as a function of interstitial velocity (V_i) as follows:

$$V_{wh} = W_{eff} \cdot V_i^{2/3} \cdot \left(1 - \exp\left(-W_B \cdot V_i^2\right)\right)^2$$

$$PV_{bt} = V_i^{1/3} \Big/ W_{eff} \cdot \left(1 - \exp\left(-W_B \cdot V_i^2\right)\right)^2$$

The introduced constants, W_{eff} and W_B, comprehensively reflecting the effects of acid concentration, permeability, temperature, and mineralogy on the wormhole propagation endow the semi-empirical model a flexible applicability at both the lab-scale and the field scale. In the newly developed model, the wormhole geometry, i.e., length, width, and locations, will be examined by considering the interstitial velocity, the fluid loss ratio, and the heterogeneity. Subsequently, a validation of the new model would be implemented using available experimental results. In addition, the validated model can be combined with a carbonate reservoir simulator to determine the wormhole geometry under various acidizing conditions. Moreover, the relationship between the wormhole geometry and acidizing stimulation performance will be quantitatively determined.

Deliverables

The completion of this project generates a pragmatic tool determining the wormhole geometry and facilitate the matrix acidizing design at both the lab-scale and the field scale. The developed tool is capable of evaluating the matrix acidizing performance in terms of acid volume to breakthrough, the wormhole growth rate, the effective wormhole volume, wormhole locations, and the dependence of production improvement on wormhole volume.

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Structural Kinematics and Mechanical Stratigraphy of the Pre-Pennsylvanian: Carbonate Research Opportunities to Augment DOE-funded Activities CO_2-Enhanced Oil Recovery (EOR) and Saline Aquifer Carbon Storage

W. Lynn Watney, Tandis Bidgoli, Jason Rush, Eugene Holubyack, John Doveton, and David Newell and others

SUBSURFACE APPLICATION: The interdisciplinary approach and current focus on understanding the role of structure in Paleozoic reservoirs are providing data and context information to test new monitoring technologies required for safe and effective carbon management and next generation CO2-EOR.
STATUS: Six plus year old DOE-funded project continues on carbon storage and monitoring including post injection monitoring of active CO2-EOR pilot and upcoming saline aquifer injection in Wellington Field via a Class VI geosequestration permit from EPA.
TIMING: Data and results are currently available to membership on integrative approaches to reservoir characterization, modeling, and evaluating safe and effective CO2 injection.
FUNDING: Extend continued baseline DOE funding to topics of interest to membership.

Purpose

New projects are invited from KICC membership to leverage a large and growing set of well and seismic data and recently completed CO2-EOR pilot injection obtained under DOE-funded (DE-FE0002056) project titled, "Modeling CO_2 Sequestration in Saline Aquifer and Depleted Oil Reservoir to Evaluate Regional CO_2 Sequestration Potential of the Western Interior Plains Aquifer System (WIPAS), South-Central Kansas complete in 2015 and contract DE-FE0006821 "Small Scale Field Test Demonstrating CO_2 Sequestration in Arbuckle Saline Aquifer and by CO_2-EOR at Wellington Field, Sumner County, Kansas" that is underway. The WIPAS includes the thick (100s meters) and deeply buried (~1500m) Arbuckle Group and the overlying Mississippian siliceous carbonates and sandstones that contain large oil and gas reservoirs in southern and southwestern Kansas. These strata are also the focus of horizontal drilling in the same area and adjoining areas or Oklahoma in the Anadarko and Arkoma basins.

Background to DOE Projects -- The DOE study (DE-FE0002056) carried out between 2009 and 2015 was focused on defining the carbon sequestration capacity of the WIPAS in southern Kansas, an area encompassing in excess of > 25,000 mi^2. Six separate studies of oil fields served as sites to evaluate carbon storage for CO_2-EOR and establishing regional saline aquifer CO_2 storage through construction of field-scale and regional 3D geocellular geomodels and fluid flow simulations. Nine hundred meters of core, extensive fluid data and well testing, modern suites of wireline logs, over 250 km^2 of reprocessed 3D seismic, and 50 km^2 of new 3D multicomponent seismic have provided the basis for multiple collaborations and thesis research. These data are complemented by regional and local remote sensing (Landsat) interpretation and reprocessed new and existing gravity and magnetic data, all made accessible via an interactive Google maps-type interface to introduce researchers to the vast subsurface rock volume.

Project Description

Newly assembled geologic and geophysical information from the DOE studies provide the basis for possible new regional and local research directed toward improved understanding of several high priority topics of interest to the petroleum industry. The rich datasets can served as the basis for further research to better understand geologic controls that impact petroleum reservoirs. Studies could evaluate concepts that could lead to drilling models for use in other analogous geologic settings and further evaluate new approaches to reservoir management in the context of carbon storage.

Structural kinematics and mechanical stratigraphy of the pre-Pennsylvanian to understand the systematics and significance of inherited structures (Figures 1, 2) as a means to forecast remaining petroleum plays, design of horizontal wells, and improve prediction of reservoir models.

Hypothesis: Episodic structural development, strongly impacts carbonate reservoirs from time of deposition to late stage diagenesis. These structural complexities impose significant heterogeneity to carbonate reservoirs and must be factored into geomodels for more accurate property assignment and more accurate and useful forecasts essential in managing carbon storage projects.

Results from studies of the Kansas dataset clearly show episodically activated structural framework that needs systematic analysis in order to reconstruct events that have important implications from petroleum systems, reservoir play delineation, and reservoir management.

Deliverables

Structural kinematics and mechanical stratigraphy of the pre-Pennsylvanian

Regional digital well log data, available seismic data, newly re-processed state-wide gravity and magnetic data, and remote sensing in southern Kansas have been used to construct a basic structural and stratigraphic framework using conventional mapping and 3D modeling using Petrel. New studies to be defined by student and staff interest will focus on aspects of the systematic reconstruction and dynamic modeling of southern Kansas and northern Oklahoma. Details would also be established by areas of interest of participating companies. Current topics of research include investigations related to evaluating regional induced seismicity using the 3D well database and model and integration of results being obtained from the Wellington seismometer array.

Application of regional structural synthesis to aid in evaluating the influence of structure on the performance of pilot-scale CO2 injections at Wellington Field.

Results of structural modeling at Wellington will be evaluated during the CO_2 injection. Monitoring methods will be used to evaluate the level of structural control vs. matrix controlled fluid flow for obtaining better forecasting on injection results.

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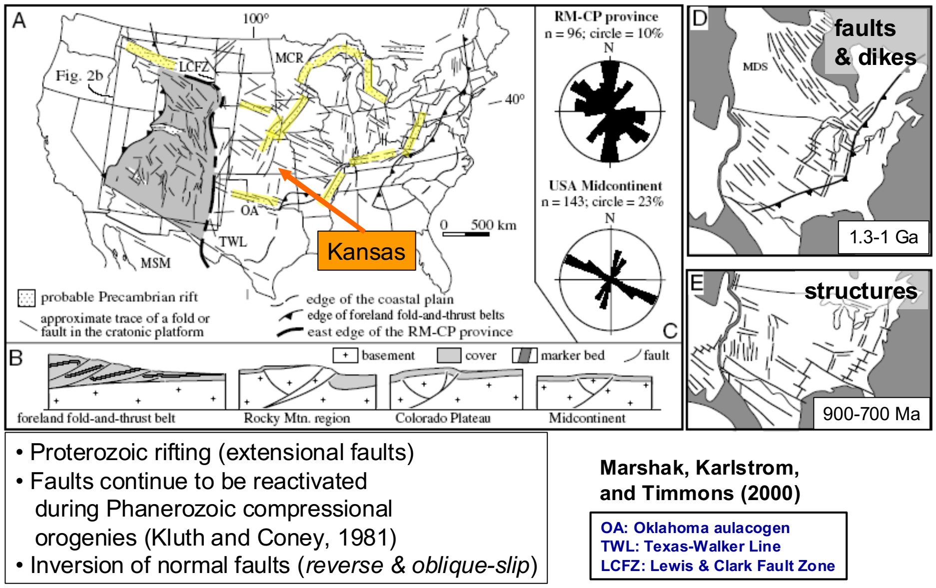

Figure 1*. Major Proterozoic rift-related and extensional faults that were affected by compressional tectonism during the Phanerozoic in the U.S.*

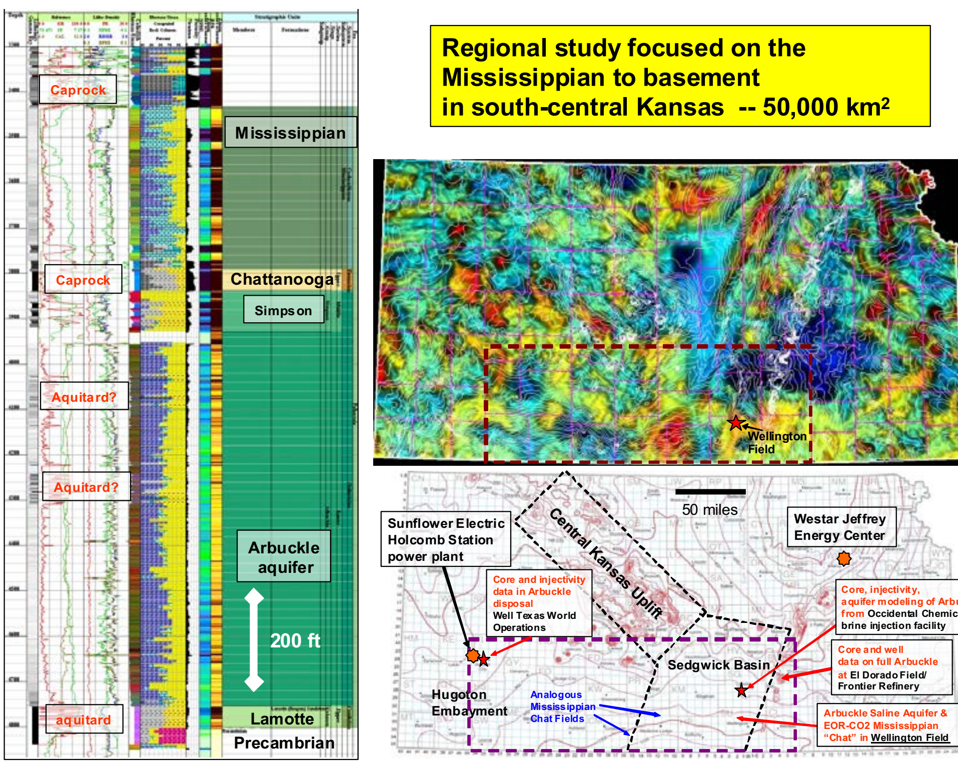

Figure 2*. Total magnetic field map of Kansas (upper right), isopach of Arbuckle Group annotated with study area in southern Kansas (right bottom), and digital log image profile of the lower Paleozoic stratigraphy in Wellington Field, Sumner County, KS.*

Polyelectrolyte and Nanoparticle Stabilized CO_2 Foams for Enhanced Oil Recovery

Negar Nazari, Jyun-Syung Tsau and Reza Barati

SUBSURFACE APPLICATION: Mississippian limestone, Lansing Kansas City.
STATUS: Long-term project in progress
TIMING: To be completed in the future if funded
FUNDING: Kansas Interdisciplinary Carbonate Consortium (KICC)

Purpose

The overall objective of this project is to improve the stability of CO_2 foam systems, used for EOR purposes, using combinations of surfactants with polyelectrolytes and polyelectrolyte complex nanoparticles (PECNPs).

Project Description

Polyelectrolytes and their complexes can potentially reduce the dynamic movement of surfactants and prevent collapse of the formed lamellae. Moreover, polyelectrolytes have been found to reduce the critical micellar concentration of surfactants, thus potentially reducing the surfactant burden.

CO_2 foam has been used to overcome aforementioned problems by dispersing CO_2 within a surfactant solution. CO_2 foams are agglomerations of gas bubbles separated from each other by liquid films with 60-97% gas content. Up to 100 times gas mobility reduction can be achieved using CO_2 foam via permeability reduction and viscosity enhancement [1]. Moreover, CO_2 foams are shear thinning fluids, and are considered an environmentally friendly material [1]. In addition to being complex systems, suffering from surfactant adsorption and poor injectivity, CO_2 foam is a thermodynamically unstable system [2]. Reportedly, long-term stability, and stability in the presence of crude oil, has been a problem [3, 4]. Polyelectrolytes can potentially reduce the dynamic movement of surfactant [5, 6] and significantly strengthen the lamellae and making a more stable interface by interacting with surfactants of opposite charge, mainly through electrostatic forces.

Laboratory experiment will be conducted at reservoir pressure and temperature to find the most stable polyelectrolytes or PECNPs systems with a nonionic surfactant in foam durability and Interfacial Tension (IFT) test. A high pressure high temperature (HPHT) view cell will be used to select the chemicals of the best performance with and without crude oil in the system. Our preliminary experiments have showed significant improvement in stability of CO_2 foam due to application of PECNPs (*Figure 1*). Effect of molecular weight and structure of polycations on effectiveness of stabilizing the foam and viscoelasticity of the interface will be studied by measuring IFT and foam column durability. A flow loop experiment will be used to examine the flow behavior of foam generated by the selected chemical systems under shear and its rheological properties. Finally, core flood experiments will be designed to demonstrate the improvement of oil recovery with the proposed chemical system and optimize the performance of polyelectrolyte and nanoparticle stabilized CO_2 foam for enhanced oil recovery (EOR) by measuring incremental oil recovery due to foam flooding and pressure drop along 10-inch cores (*Figure 2*).

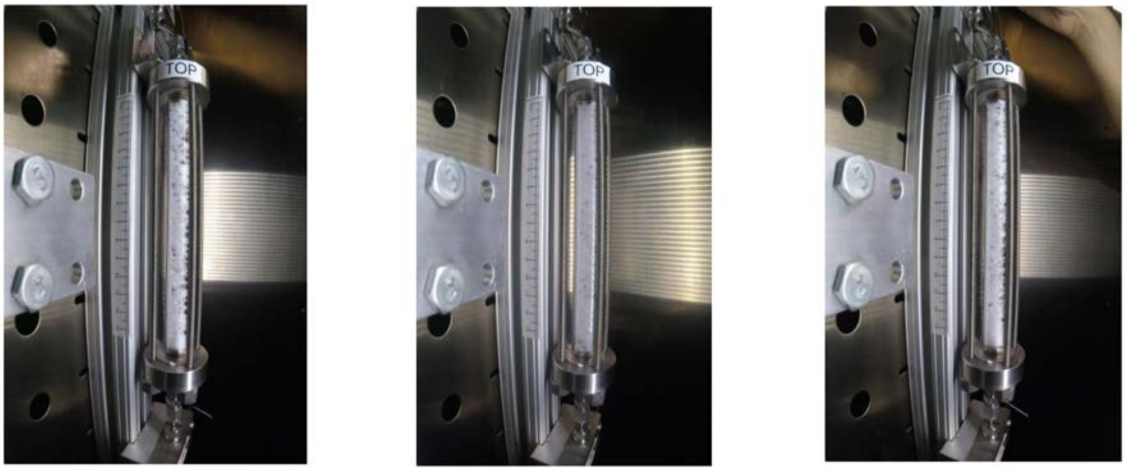

Figure 1. *Foams generated without crude oil with surfactant (left) surfactant-PEI (middle) and surfactant-NP (right) at 40 °C and 1300 psi.*

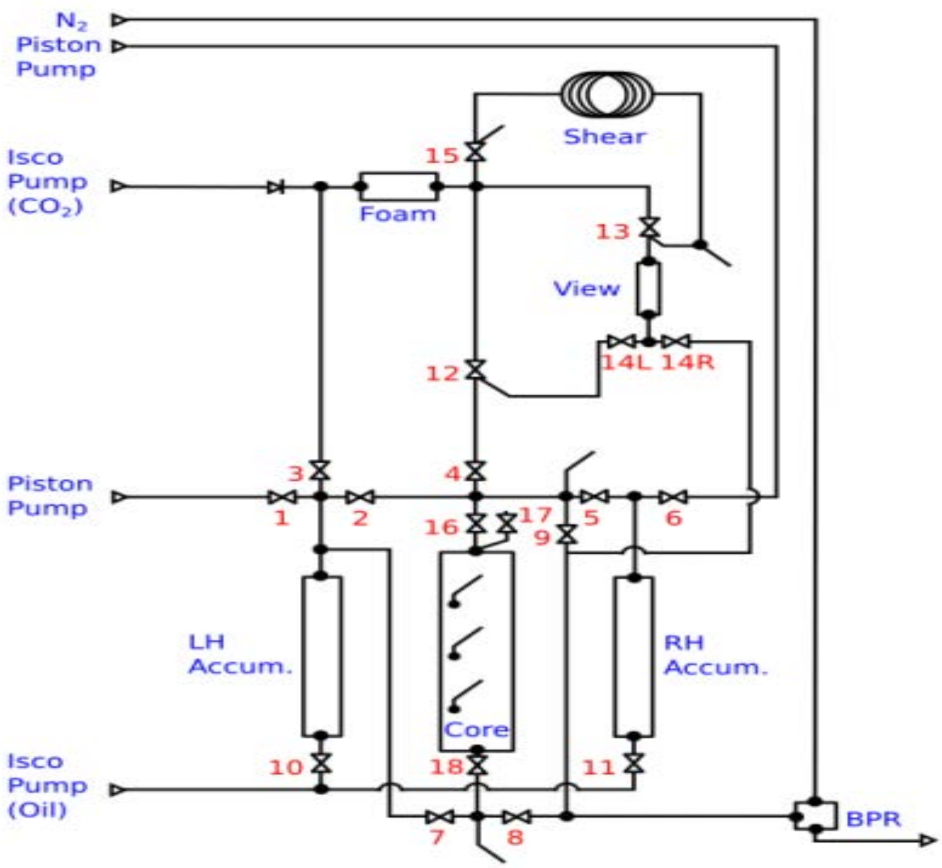

Figure 2. *Core flood system prepared for the injection of CO2-foam into a long core either 100% saturated with brine or brine at residual oil saturation.*

Deliverables

Successful completion of this project will provide a novel chemical system to improve mobility control for CO_2 application in EOR with stabilized foams. A surfactant-polyelectrolyte (s) system capable of generating stable CO_2-foam in the presence of crude oil, showing stable rheological properties under shear, and incremental crude oil and stable pressure drop across long cores is aimed to be the main deliverable of this research.

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Understanding the Underlying Mechanisms of Low Salinity and Modified Salinity Water-Flooding Processes for Limestone Formations

Reza Barati and students

SUBSURFACE APPLICATION: Lansing Kansas City limestone intervals, Oread and Foraker
STATUS: Long-term project in progress
TIMING: To be completed in the future if funded
FUNDING: Kansas Interdisciplinary Carbonate Consortium

Purpose

The goal of this study to investigate the effect of salinity modification on Lansing-Kansas City (LKC) limestone intervals via the evaluation of incremental oil recovery, relative permeability and capillary pressure curves, **i**nterfacial properties between crude oil and brine and the ion exchange mechanism.

Project Description

The potential of incremental oil recovery via reduced/modified salinity brine, low/modified salinity waterflooding (LMSW), from sandstones has been well studied. Incremental oil recoveries of 2-10% have been also reported for carbonates due to modification of injected water composition (Strand et al. 2008; Ligthelm et al. 2009; Romanuka et al. 2012). Despite the controversy regarding the LMSW mechanisms, the effect of these mechanism(s) on relative permeability and capillary pressure curves has been postulated and used for the simulation of LMSW processes. However, even though the relative permeability and capillary pressure has been used to match the displacement results (Romanuka et al. 2012), a complete study of the effect of LMSW on carbonate rocks is yet to be done.

LKC reservoirs have been exposed to waterflooding for many years (Allison, 1959) and have contributed to the 47% oil production of the State of Kansas that comes from Pennsylvanian formations (Evans and Newell, 2013). The low/modified salinity waterflooding will potentially bring an economically viable option to enhance the income even for small producers in the State of Kansas.

To obtain full characterization of the LKC limestones, three sets of LKC core plugs will be used. The cores will be cleaned using a Dean-Stark apparatus and then saturated with synthetic LKC brine. Initial water saturation will be established for all core plugs. The cores will be aged in LKC crude oil to simulate the initial reservoir conditions. The following experiments will be conducted with various salinity and brine compositions:

- The first set of core plugs: Spontaneous imbibition tests will be conducted to study the wettability state of the cores.
- The second set of core plugs: The oil/water relative permeability curves will be generated. These cores will be flooded with brine with similar composition at the reservoir brine and at their residual oil saturation to study modified salinity waterflooding as an improved oil recovery method.
- The third set of core plugs: Capillary pressure curves.

- To investigate the effect of salinity modification on interfacial properties between oil and water for LKC, IFT and contact angle measurements will be conducted by Pendant Drop Method. The interfacial properties will be correlated to oil-water and oil-water-rock interface properties.
- To study the effect of salinity modification on ion exchange between rock and oil-water system, a baseline ion exchange test will be conducted. Cores which will be saturated in synthetic brine which is analogue to LKC formation will be flooded with various salinity and composition of brines for at least 20 PV. The brine effluents will be analyzed by Inductively Couple Plasma Optical Emission Spectroscopy (ICP-OES).
- A simulation study of the lab experiments will be conducted next to extract properties for the field scale modified waterflooding simulation for LKC reservoirs.
- An inverted 5-spot pattern will be selected in a LKC reservoir in order to conduct a pilot test of low salinity waterflood and analyze the production and injection data.

Deliverables

This project will provide full characterization of the LKC limestone formation including LKC crude oil properties, wettability alteration (contact angle, Amott Harvey test and relative permeability), the interaction between crude oil and brine (dynamic and equilibrium IFT) as well as oil displacement studies. Moreover, a correlation will be sought between wettability and SCAL properties for different water salinity and compositions.

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Development of an Environmentally and Equipment Friendly Alternative for Matrix-Acidizing and Acid-Fracturing Applications

Reza Barati and students

SUBSURFACE APPLICATION: Mississippian limestone, Lansing Kansas City limestone intervals, Arbuckle, Austin Chalk, Buda limestone, Bakken, Eagle Ford, Niobrara
STATUS: Proposed project
TIMING: Preliminary results available; to be completed in the future if funded.
FUNDING: Seeking funding

Purpose

The overall objective of this project is to evaluate the performance of Ultraseries FF-01 (FF-01)as an environmentally- and equipment-friendly alternative for HCl that can be used for matrix acidizing and acid fracturing of wells producing from limestone formations. Specifically, this project will focus on developing this new product for the Mississippian Limestone Play (MLP) reservoirs in Kansas by evaluating the performance of FF01 as a single component product to be injected followed by evaluation of blends of FF01 and different polymers used in hydraulic fracturing of limestone formations.

Project Description

Well acidizing is one of the most common practices in the oil industry. Hydrochloric acid (HCl) has been used as the main acid for limestone stimulation purposes [1]. However, serious concerns regarding the health and safety of the field crew, corrosive nature of the acids for the tubular and equipment, environmental effects of the produced HCl, and rapid spending rate of HCl that prevents deep penetration into the formation has lead the industry towards a more environmentally and equipment friendly product [2]. FF01 is an environmentally- and equipment-friendly product of 101st Earthborn Environmental Technologies LP, which is a conversion to an organic carrier to maintain very low pH as a vehicle for aggressiveness, along with the creation of buffers and surface tension relievers for the effectiveness and safety [3]. Low pH, linear reaction with limestone, small amount of residue after reaction, longevity and higher viscosity than water with shear thinning behavior are the properties of this product.

The Mississippian Limestone Play (MLP) has become an important source of income for both Kansas and Oklahoma with hundreds of horizontal wells drilled and completed and millions of dollars of extra income [4, 5]. Acid treatment of oil wells with the purpose of increasing their productivity is a very common practice in the MLP. Considering the millions of barrels of fluids that are being used for acid treatments, use of a more environmentally- and equipment- friendly product will both save the companies money on their equipment and prevent the exposure of the acidizing crew and surface environment to HCl, both in liquid and vapor forms.

A complete lab study of this product including rheological, core-flooding and fracture conductivity tests at reservoir and ambient conditions will be followed by a matrix acidizing field test in a MLP production well.

During the research and development phase of this project:

- Rheological measurements will be conducted for FF01 and blends of FF01 with guar and hydrolized polyacrylamide (HPAM) products used for hydraulic fracturing of wells.
- HPHT reaction experiments will be conducted using a rotating disk setup and reaction parameters will be calculated by measuring the Ca concentration vs. time as a result of the acid reaction.
- Core-flooding experiments using different concentrations and blends of FF01 with each fracturing polymer as viscosifying agents and fracturing fluids will be conducted at reservoir conditions.
- Fracture conductivity measurements for fractures generated using the selected fluids will be conducted at reservoir conditions. Base cases will also be conducted using HCl for both ambient and reservoir conditions.

The final products most suitable for matrix acidizing and acid fracturing will be selected and the conditions of different wells owned by the producer will be studied to select a MLP well with the most appropriate conditions for matrix acidizing. The field test will be designed and conducted. Post-treatment data will be analyzed.

Deliverables

The deliverables are: 1) an optimized recipe and designed blends using acid alternatives and hydraulic fracturing polymers including a comparison of rheological properties (Figure 1), 2) Comparison of reaction parameters for commercial blends used in the industry with this novel environmentally-friendly product, 3) incremental permeability induced by matrix acidizing and acid fracturing using this new product (Figure 2) compared with HCl, and 4) improvement in the overall productivity due to acid fracturing using HCl alternatives.

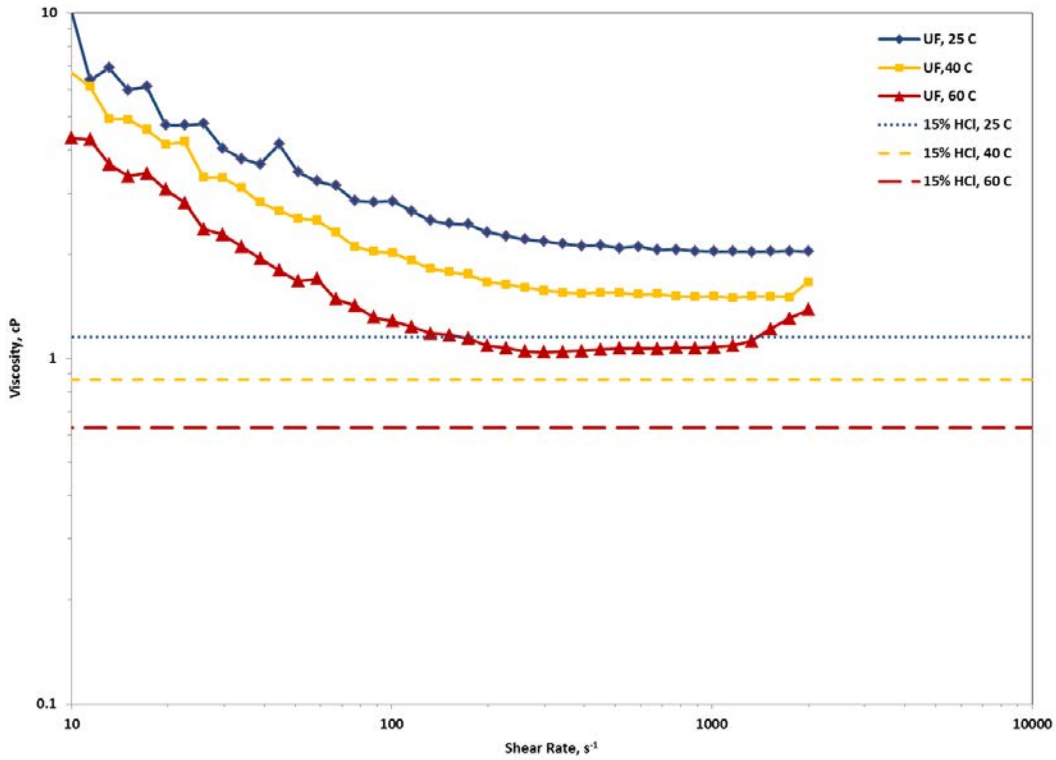

Figure 1. *Viscosity versus shear rate for FF-01 and 15% HCl at 25 °C, 40 °C, and 60 °C.*

Figure 2. *The LHS picture presents a core sample after a matrix acidizing experiment is performed. The RHS picture is a core sample after an acid fracturing experiment was performed.*

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CO_2 Flooding to Improve Oil Recovery in Carbonate Reservoirs

TORP Staff, Graduate student

SUBSURFACE APPLICATION: Arbuckle reservoirs in Kansas or other similar type of reservoirs with operation pressure below minimum miscibility pressure
STATUS: Long-term project
TIMING: Significant results to be reported – Results currently available to membership
FUNDING: TORP

Purpose

Carbon dioxide (CO_2) injection for enhanced oil recovery is a proven technology. It is also considered as one of the most promising methods for carbon sequestration in geologic formations. CO_2 injections are normally operated at a pressure above the minimum miscibility pressure (MMP), which is determined by crude oil composition and reservoir conditions. However, many reservoirs in the United States and around the world are at shallow depths or geologic conditions exist such that they operate at pressures below the MMP. When CO_2 injection operates at a pressure below the MMP, displacement efficiency decreases as a result of the loss of miscibility but is still better than that in a waterflooding process. This better recovery has been attributed to possible improvement of the mobility ratio displacement and an extraction process, which are all closely related to operating pressure. To increase the resource base for CO_2 flooding and substantially increase the production from reservoirs, there is a need to characterize the near miscible conditions of reservoirs and investigate the feasibility of CO_2 displacements at near miscible pressures by conducting appropriate experimental work and reservoir simulation.

Project Description

Arbuckle reservoirs historically have been viewed as fracture-controlled karstic reservoirs with porosity and permeability influenced by basement structural patterns and subaerial exposure. These reservoirs have produced an estimated 2.2 billion barrels of oil representing 35% of the 6.1 billion barrels of oil of total Kansas oil production and are a significant resource in Kansas for improved oil recovery. Initial studies of CO_2 miscible flooding indicated that miscibility is not achievable at the reservoir operating pressure in most Arbuckle reservoirs. On the other hand, if the reservoir operating pressure is above the MMP, CO_2 miscible process can be considered to improve the oil recovery. An example of such a reservoir is located at a depth of about 2900 feet in Hall Gurney Field, Russell County, Kansas.

The objective of this project is to investigate the feasibility of applying CO_2 displacement at miscible or near miscible pressure to increase the resource base for CO_2 flooding and substantially increase the production from these reservoirs. The proposed work includes experimental and simulation studies. The experimental study will 1) systematically characterize the miscible and near miscible condition and study recovery of waterflood residual oil using CO_2 displacement at near miscible pressure, and 2) identify key parameters in phase behavior and flow tests for simulation modeling. The simulation study will develop a representative model to simulate miscible and near miscible displacement physics and 2) assess the potential of recovery processes at miscible and near miscible pressures.

Deliverables

The project will develop a methodology to design field application of carbon dioxide injection at near miscible and miscible condition. Economics of pilot/demonstration and field application on carbonate reservoirs of interest will be evaluated.

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Carbonated Water Injection to Improve Oil Recovery in Carbonate Reservoirs

TORP Staff, Graduate student

SUBSURFACE APPLICATION: Kansas carbonate reservoirs such as Arbuckle, Lansing Kansas City and Mississippian formation
STATUS: Long-term project
TIMING: not yet available to membership
FUNDING: TORP

Purpose

Carbonated water injection (CWI) is a promising alternative of conventional CO_2 flooding, requiring less amount of CO_2, to improve oil recovery. The solubility of CO_2 in water is high as compared to other gases commonly used in gas injection process. During the CWI, the dissolved CO_2 transferred from the injected water to the oil phase increases the oil mobility as a result of oil viscosity reduction and swelling. However, the solubility of CO_2 depends on reservoir temperature, pressure and water salinity. Many carbonate reservoirs in Kansas produced a large amount of water with high salinity either under water flooding or through the natural water drive by aquifer. It is challenging to dispose huge amounts of water associated with such a field operation. As a result, utilizing the produced water with enrichment of CO_2 as a displacing agent is proposed to improve oil recovery (IOR) in these carbonate reservoirs.

Project Description

Arbuckle reservoirs have produced an estimated 2.2 billion barrels of oil representing 35% of the 6.1 billion barrels of oil of total Kansas oil production. Lansing Kansas City (LKC) group is the second largest unit in Kansas with over one billion barrel recovered to date. It accounts for 19% of Kansas total oil produced each year. Since 1970, 12% of state's total oil production also came from Mississippian formations. All these carbonate reservoirs remain a significant resource in Kansas for improved oil recovery. CO_2 miscible and near miscible process has been considered to improve the oil recovery in these reservoirs at Hall Gurney Field, Russell County and Ogallah Unit, Trego County, Kansas. However, due to the lack of CO2 source nearby, commercial filed application has not been implemented.

The objective of this project is to investigate the feasibility of applying CWI as an alternative to conventional CO_2 flood for improving oil recovery on these carbonate reservoirs. The proposed work includes experimental and simulation studies. The experimental study will 1) systematically characterize the IOR mechanisms of CWI which include partition of CO_2 in water/oil phase, dynamic wettability alternation of carbonate, carbonate dissolution and deposition due to the presence of CO_2 in water, and 2) identify key parameters of interaction between fluid/fluid and fluid/rock for simulation modeling. The simulation study will develop a representative model to simulate laboratory core flooding experiment, and 2) assess the potential of recovery processes at a field scale.

Deliverables

The project will develop a methodology to design and conduct laboratory experiment and future field application of carbonate water injection. Economics of pilot/demonstration and field application on carbonate reservoirs of interest will be evaluated.

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Chemical Flooding for Improved Oil Recovery in Carbonate Reservoirs

TORP Staff, Graduate student

SUBSURFACE APPLICATION: Trembley oilfield in Kansas
STATUS: Long-term project
TIMING: Significant results to be reported
FUNDING: Partial from DOE

Purpose

Successful field applications of chemical flooding rely on a high-quality design. Laboratory evaluation to determine an efficient chemical formulation for an oil/brine/reservoir system, and reservoir simulations to predict performance and economic evaluation of the process are key elements of the design. The principal objective of this project is to supply the design work for chemical flooding processes that is necessary for oil producers to make an informed assessment for implementation of a pilot or demonstration project.

Project Description

Generally, more than half of the oil is left in the ground at the end of waterflooding operations due to partial sweep of the reservoir by the water and the residual oil that is left where the water has invaded. Chemical flooding has the potential to displace and produce a significant portion of that remaining oil. A slug of a chemical formulation is injected and displaced through the reservoir. The chemical formulation, which includes surfactants, solvents, polymer and/or alkali, is designed for the particular oil/brine/reservoir rock system. TORP is presently classifying Kansas reservoirs for their chemical flooding potential. The proposed work includes 1) conduct laboratory testing under reservoir conditions to screen different chemical formulations for carbonate reservoirs of interest, 2) determine field responses to chemical flooding by reservoir simulations, and 3) evaluate economics of pilot/demonstration and field applications.

Deliverables

The project will develop a database of carbonate reservoirs that are used to screen, rate and study for future field application. Laboratory and simulation results will be used to assess the potential oil recovery at carbonate reservoirs of interest.

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Microbial Enhancement of In Situ CO_2 Sequestration

Jennifer Roberts and David Fowle

SUBSURFACE APPLICATION: Applicable to Mississippi Lime; Arbuckle Aquifer and other reservoirs targeted for tertiary recovery via CO_2 injection or aquifers targeted for CO_2 storage.
STATUS: Project Proposed
TIMING: To be completed in the future if recommended by membership, funded, or staffed
FUNDING: None

Purpose

In recent years there has been significant advancements investigating aquifers, mine tailings, and oil fields as a long-term storage solution for carbon dioxide. One potential fate for injected CO_2 is sequestration of CO_2 into sparingly soluble carbonate minerals. Whereas microorganisms are known to facilitate precipitation of carbonate minerals, it remains unclear whether they promote carbonate precipitation in CO_2-injected reservoir systems. Here we will investigate: 1) the extent that microorganisms and other functionalized particles influence carbonate precipitation under reservoir temperatures and pressures in the presence of super critical CO_2 and high partial pressures of CO_2, and; 2) strategies to enhance precipitation kinetics through stimulation of *in situ* native microbial communities or injection of natural or engineered materials.

Project Description

The introduction of high partial pressures of CO_2 into the subsurface will influence mineral solubility. The dissolution and precipitation of mineral phases will lead to changes in reservoir permeability, and the potential sequestration of CO_2 into insoluble carbonate minerals. These abiotic processes have been investigated at the bench (e.g., HANSEN, et al., 2005) and field scale (e.g., KHARAKA et al., 2006) yet influences on these processes by native microorganisms and other charged surfaces remain unclear. Because microorganisms have been shown to be integral to carbonate mineral formation in some environments (Figure 1), in this study we will develop strategies to enhance carbonate mineral precipitation under reservoir conditions. We hypothesize that:

- Microbial activity and reactive surfaces can enhance rates of carbonate mineral precipitation; and
- By distinguishing the mechanism of precipitation, we can engineer protocols to enhance these processes *in situ*.

These hypotheses will be tested using controlled laboratory batch experiments containing native consortia from reservoir fluids. We will characterize precipitation of carbonate phases as a function of solution chemistry and the presence/absence of cells; and characterize precipitation of carbonate phases as a function of solution chemistry and active metabolic pathways.

Deliverables

We expect precipitation of carbonate phases will be facilitated by both metabolic activity and cell wall interactions. By characterizing the abundance and types of microorganisms in a specific system we can produce better estimates of sequestration and devise approaches to enhance sequestration. Specific deliverables include: 1) quantitative data to assess the rate of carbonate precipitation under reservoir conditions as a function of biomass; 2) implementation of experimental data in conjunction with site specific characterization of microbial populations into predictive models; and 3) engineered approaches for enhancing carbonate precipitation *in situ* including enhancement of carbonate-precipitating metabolic activities or bioaugmentation.

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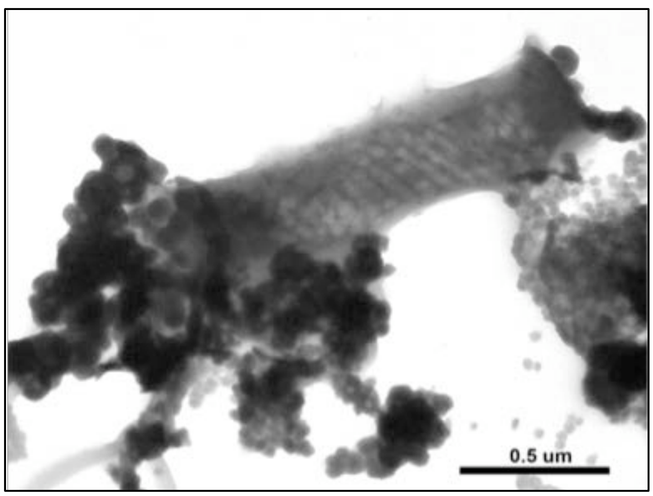

Figure 1. *TEM photomicrograph of a microbial surface coated in carbonate precipitate.*

Next Generation of Integrated Reservoir Modeling and Intelligent Surveillance

Dr. Masoud Kalantari

SUBSURFACE APPLICATION: Both conventional and unconventional reservoir with large number of wells
STATUS: Long-term project
TIMING: Significant results to be reported – Results currently available to membership

Purpose

Reservoir management today is facing remarkable challenges in optimizing profitability (i.e. Maximize recovery while minimizing capital expenditures and operating costs). In complex reservoirs, uncertainty in the reservoir and fluid characterization, complex physics and handling a large volume of spatial-temporal high dimensional data from experiments, operations, make the reservoir management and surveillance very challenging. Surveillance programs are part and parcel of initiatives aimed at the reservoir characterization, development, and management. These programs result in different actions being taken depending on the stage of field development. Surveillance programs are not merely data-gathering exercise but impact routing and long-term decision. If a set of measurement do not reduce the uncertainty and do not directly, assist in determining or changing the decision, the value of the acquisition of that piece of data is questionable.

Project Description

The mission of Integrated Subsurface Modeling and Smart Field Center of Excellence at The University of Kansas (KU) is to investigate innovative approaches that enable revolutionary advances in subsurface science especially in the areas of numerical simulation and machine learning systems. We have full capability for development of hybrid numerical, analytical and empirical models of real and complex processes using collected data at any frequency, volume and scale (Molecular, Micro, Core and Full-field). This includes researches that primarily result in evolutionary improvements to the existing state of practice. This research provides the industry with the state-of-the-art, novel and integrated technology for fast and accurate reservoir management and decision-making.

Through the Joint Industry Project program, our modeling center of excellence will support operators by offering fit-for-purpose modeling solutions using industry standard and the-state-of-the- art technologies in modeling and simulation. We offer practical solutions to maximize the life cycle value of the assets by developing machine learning-based models, simulation models, and analytical models.

The integration across heterogeneous, interdependent and complex data resources for efficient decision making, collaboration, and ultimately value co-creation of complex subsurface processes aspects lead to data conversion into actionable intelligence and provides:

- Better understanding of complex subsurface system.
- Handling extremely large database (billions of data points).
- The ensemble of machine learning, numerical simulation and analytical models and optimization techniques.
- Integration of SME feedbacks with sophisticated algorithms.
- Better and more efficient reservoir monitoring & management:
  - Identify new sweet spots
- Recommend well type, placement, and optimize trajectory
  - Candidate well selection for workover, PTA, PLT and artificial lift optimization
  - Optimize flood pattern and performance
  - Quick diagnostic
  - Update the model when new data become available
  - Minimize the field reservoir management cost

Deliverables

The project will develop a methodology and tools for efficient reservoir surveillance to maximize the recovery while lowering the cost.

Experimental Studies of Geofluid Interactions with Carbonate Rocks in Sedimentary Basins

Jennifer A. Roberts and David A. Fowle

SUBSURFACE APPLICATION: Applicable to modeling carbonate reservoir diagenesis or testing hypotheses of "production-induced" diagenesis in produced carbonate reservoirs.
STATUS: Project Proposed
TIMING: New laboratory and analysis June 2014-February 2015
FUNDING: Seed funding from KICC awarded.

Purpose

Due to experimental limitations, thermodynamic and kinetic data for mineral dissolution and precipitation typically are extrapolated to the temperatures and pressures appropriate for sedimentary basins. These data are central to reactive transport and basin evolution models used for prediction of reservoir quality. Extrapolation of these data are questionable, and new data from experiments conducted at conditions appropriate to the deep subsurface remain integral for understanding both the formation and evolution of porosity and permeability in sedimentary basins. Model experimental systems are critical to able to predict, for example, how fracking fluids or supercritical carbon dioxide will impact the integrity of shales and other seals, how mobile radionuclides, sourced from reservoir and seal dissolution, will behave in deep repositories, and how reservoir carbonates form and evolve under basinal temperatures and pressures (e.g. Cantucci et al., 2009; Kazuba et al., 2003). Furthermore, these systems lack any conceptual framework regarding the role of microorganisms in these processes, which are critical to the kinetics of many early diagenetic reactions below temperatures of 80 °C (e.g. clay diagenesis, carbonate cementation).

The goal of the proposed study is to generate preliminary data in our new high-temperature, high-pressure experimental geofluids laboratory generating rates of carbonate mineral precipitation and dissolution under reservoir temperatures and pressures.

Project Description

As principal investigators in a collaborative US Dept of Energy (DOE) project modeling carbon dioxide sequestration in a deep saline aquifer and a depleted oil reservoir, we have undertaken experiments to study shale cap rock dissolution, and precipitation reactions and kinetics at high temperatures and pressures in the presence of microbes and supercritical CO_2 at a DOE national lab. Specifically, we have developed protocols for high T and P experiments in batch reactors and flow through reactors that are comparable to reservoir conditions. The experimental data produced can be coupled to high-resolution x-ray CT scanning and *ex situ* geochemical and gas phase analysis to provide new mechanistic insights into diagenetic and reservoir reactions, products, and rates (after Regnault et al., 2009). Through funding in hand from the University for the experimental geofluids laboratory we propose to develop a line of research focused on Carbonate Reservoirs in collaboration with KICC and ultimately industry sponsors.

We will begin our studies by investigating the impact of a gradient of temperature and pressure on a variety of carbonate sediment samples, including primary dolomites produced in our laboratory (e.g. Kenward et al, 2013; Roberts et al. 2013), Arbuckle dolomite, and so-called "oil shales" (e.g. Pierson Formation) in the overlying Mississippian units. Specifically, we will 1.) investigate how mineral equilibria change under $CO_{2(SC)}$ injection, 2.) quantify the rates of dissolution and precipitation reactions, and 3.) assess how these reactions will impact reservoir and seal porosity and permeability. A critical and unique aspect of the proposed project will include microorganisms as a variable to investigate whether native microbial communities, their metabolic byproducts (e.g. organic acids, dissolved organic carbon) or cells themselves influence the rates, mechanism and outcomes of the previous questions. These experiments will be conducted using individual minerals, complex mineral mixtures and core samples from the basins of interest in collaboration with KICC and industrial partners. Fluid geochemistry and microbial communities will be modeled on reservoir brines characterized from drill stem tests and swab fluids. Reaction progress will be followed using solution chemistry, stable isotopes, pore and surface area measurements, XRD, and electron microscopy.

The initial work and deliverables for the proposed work will focus on reactions with Arbuckle and Mississippian materials in the presence of $CO_{2(SC)}$. We will also use this as an opportunity to observe "ripening" processes in our laboratory-precipitated dolomite, however these efforts will be purely exploratory at this point in time.

This work will provide a first step in understanding critical thermodynamic and kinetic parameters necessary to predict basin scale pore water and reservoir evolution based on sorption, precipitation/dissolution kinetics, and biological activity.

Deliverables

Specific deliverables include: 1) The first results for experimental microbial geochemistry of carbonates at high temperatures and pressures; 2.) Preliminary mechanistic, morphological and kinetic data on *in situ* of carbonate precipitation and dissolution with and without reactive microbial surfaces in the same environments, 3.) At least one manuscript and development of a larger NSF or industry supported proposal.

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