May Newsletter

One-Day Technology Meetings Update

Shale Gas meeting

The Shale Gas meeting held on May 18th was a great success and has already generated topics for the next Shale Gas meeting to be held this Fall on December 8th. The agenda, attendees list, presentations, excel spreadsheets, and video for this meeting can be found here.

Heavy Oil and IOR Methods Research meeting

The Heavy Oil and IOR Methods meeting on May 20th was also successful, with 10 companies in attendance. The agenda, attendees list, presentations, and video for this meeting are located here.

Enhanced Oil Recovery meeting will take place on Tuesday, June 1st.

Various topics on enhanced oil recovery will be covered during a series of presentations. The impact of low salinity water, especially sulfate ions, will be discussed. The impact of salinity on interfacial tension and wettability are examined at high temperature and pressures encountered in deep oil wells. The impact of lithology on oil recovery using different salinity waters is then examined. Screening of polymer and surfactants for chemical EOR, and potential formation damage due to chemical EOR will be addressed. We will also introduce a new environmentally friendly clay stabilizer for use in sandstone formations. Finally we will address the use of viscoelastic surfactants in chemical EOR. Rheology of EOR polymers and surfactants will be discussed.

Student researchers will deliver the majority of presentations in this meeting. As always, sponsors are encouraged to provide feedback and set priorities for the Crisman research projects presented.

Well Productivity meeting to take place on Wednesday, June 2nd.

Productivity subjects such as effective stimulation fluids for deep carbonate reservoirs, removal of filter cake and barium sulfate scale, impact of organic acids/chelating agents on the rheological properties of amidoamine oxide surfactant, measuring reaction rates of in-situ gelled acids using a rotating disk apparatus, propagation and retention of viscoelastic surfactants following matrix acidizing treatments, and acid diversion in carbonate reservoirs using polymer-based in-situ gelled acids are among some of the topics to be discussed. Student researchers will deliver the majority of the presentations.
Introduction

The Woodford shale gas is an ultra-low permeability reservoir (0.000001 md to 0.001 md). Commercial gas production is made possible by hydraulic fracture stimulation. Optimum hydraulic fracture treatment design needs to consider geomechanical principles in fracture initiation and propagation of multiple transverse fractures in horizontal wells. Often, Woodford shale reservoir development is achieved by drilling multiple parallel horizontal wells (on N-S azimuth), with approximately 600 ft spacing. Each treatment stage in a well is designed to create a stimulated volume, defined as the rock volume contacted by treatment fluid and proppant, which experiences a desired enhancement to permeability. For reservoir optimization, the collective network of stimulations should affect the maximum volume, with minimal (optimal) overlap of adjacent treatment stages.

Objectives

The problem has several related components: the selection of an appropriate perforation scheme for open and cased hole for initiating multiple fractures within a fracture stage and the determination of an optimum fracture treatment spacing for a 1000 ft section of a well using fracture mechanics models. The latter should consider the interaction between neighboring wells in generating a stimulated volume. In this research, we present a survey of state-of-the-art practices with reference to the above issues to assist in selecting the best strategy for the Woodford shale reservoir.

Approach

In wells with low to medium permeability like Woodford’s, transverse fractures that extend sideways provide drainage for a larger area of the formation, experiencing a long-term production increase.

A major concern in designing the perforation clusters for transverse fracturing design is the stress-shadow effect. When a hydraulic fracture is opened, the resulting compression will increase the amount of minimum horizontal stress because of the net fracturing pressure existence. If this compressional stress is big enough, it can turn minimum horizontal stress into maximum horizontal stress, thus changing a transverse fracture into a longitudinal one.

By reducing the number of clusters per stage, stress interference can be minimized, which will reduce the likelihood of having improper fracture propagation. However, this reduction will increase the number of stages per well, which means more completion costs. Therefore, the number of stages and the spacing between the perforation clusters are the result of optimization between the cost of having more stages and reducing the stress shadow effect. For our cemented horizontal wells, the best completion strategy is to limit the number of stages and stimulate two or three perforation clusters per stage.

Accomplishments

Our study on stress shadow shows that it becomes quite small at an offset distance equal to about two times the fracture height (2H). This minimum spacing (2H) is required to effectively minimize the conflicts between two transverse fractures. Also the perforation-cluster lengths should not be longer than four times the wellbore diameter. This is to prevent the creation of competing multiple fractures. Considering the fracture height of 250 ft to 280 ft for Woodford shale formation (Vulgamore et al., 2007), and a horizontal lateral diameter of 7 in, the best option will be to have three perforation clusters with maximum lengths of 2 ft that are stimulated in a single stage for each 1000 ft of horizontal lateral.

To align perforations with the preferred fracture plane, they should be oriented 0°/180° phasing. The other alternative is 60° phasing when used in conjunction with an acid-soluble cement system. Both perforation strategies have shown to be effective (Ketter et al., 2008).
Optimization of Horizontal Well Performance in Low-Permeability Gas Reservoirs

Objectives

The objective of this research is to develop an approach to evaluate horizontal well performance for fractured or unfractured gas wells, and to conduct a sensitivity study of gas well performance in a low permeability formation. Different mathematical model approaches will be used, including analytical solutions, Point/Line source method, and Slab Source method for numerical simulation. The methods will predict a production index for horizontal wells. In addition, permeability, well trajectory, and fracture geometry, which are critical parameters for horizontal well and hydraulic fracturing design, will also be studied.

Approach

Analytical Solution

Many horizontal well models have been developed for both steady-state flow and pseudo-steady flow. However, for tight gas formation, the flow is more likely to have a longer transient period. The performance of transient flow for horizontal gas wells should be studied in this research.

Point/Line Source Solution

A line source solution for horizontal well has been developed by Kamkom (2007). Investigate the possibility of using point source to represent fracture performance.

Slab Source Solution

The research will use the slab source method to predict well performance of a single fracture and multiple fractures. By comparing results with line source solution, the difference will be discussed.

Significance

This project is a major initiative to review current fractured horizontal well performance in Analytical/semianalytical approach. The results of this project allow comparing, quickly and more flexibly different completion types and different boundary conditions reservoir to select an optimization method to decide the horizontal well length and the numbers of fractures.

Accomplishments

- Slab source method has been developed to calculate the horizontal well, which has a good match with the corresponding analytical method.
- Horizontal well with more than one fracture has been solved for both transient and pseudosteady state conditions (Fig. 1).
- For finite conductivity boundary conditions, the fracture was divided into several segments, and the pressure drop can be calculated by superposition theory (Fig. 2).

Future Work

The ultimate goal of this project is to develop a model and computation tool that will help in calculating the performances of oil/gas horizontal wells, with other aspects conducted in the performances of fractures. By integrating these two topics, a system can be created to aid the industry to develop hydraulic fracture horizontal wells more economically and efficiently.
Introduction

Poro-thermo-mechanical processes and mineral precipitation/dissolution change the fracture aperture and thus affect the fluid flow pattern in the fracture.

Different aspects of thermal and mechanical processes have been studied (e.g., Ghassemi and Zhang, 2004; Ghassemi et al., 2005, 2007, 2008, and 2009). The thermoelastic effects are dominant near the injection when compared to those of poroelasticity. Under some conditions, silica reactivity tends to dominate permeability (Kumar and Ghassemi, 2007). Experimental studies (Carroll et al., 1998; Johnson et al., 1998; Dobson et al., 2003) also show that chemical precipitation and dissolution of minerals significantly affect fracture aperture.

Objectives

We will study this phenomenon by the development and application of a three-dimensional poro-thermoelastic model incorporating mineral dissolution/precipitation effects.

Approach

Simulating the poro-thermoelastic chemical mechanisms usually requires solving a coupled set of equations (e.g., fluid flow, heat transport, solute transport/reactions and elastic response of the reservoir). These processes are coupled and non-linear. In this work, the solid mechanics aspect of the problem is treated using poro-thermoelastic displacement discontinuity method (Ghassemi et al., 2009), while reactive flow and heat transport in the fracture is solved using finite element method. Similarly, the solution system in the reservoir rock is obtained using the boundary element method. We focus on single-component mineral reactivity and its transport in the fracture. The solute reactivity and solubility in fracture plane is considered using a temperature dependent formulation (e.g., Robinson, 1982, and Rimstidt and Barnes, 1980).

Significance

We apply the model to simulate the process of low-temperature fluid injection and production of high-temperature fluid in a hot-rock-reservoir, and thus its impact on mineral mass distribution, pore pressure and thermal stress. Recent computations include temporal evolution of mineral concentration and its dissolution/precipitation, temperature, and fluid pressure in the fracture.
Introduction

The data assimilation process of adjusting variables in a reservoir simulation model to honor observations of field data is known as ‘history matching’ and has been extensively studied for few decades. However, despite the progress that has been made, development of more accurate and efficient history matching techniques that produce geologically realistic outcomes (reservoir models) is still one of the main challenges for reservoir engineers, mainly due to the high complexity of the problem, data scarcity, and computational demand for field applications. Because of the insufficient information about reservoir spatial property distribution, history matching of heterogeneous reservoirs is an inherently ill-posed inverse problem; that is, it is possible to obtain several reservoir models that honor observed measurements but have geologically distinct features and provide incorrect predictions. Two common approaches to deal with ill-posed history matching problems are either to constrain the structural form of acceptable solutions (regularization) or to reduce the number of unknown parameters (reparameterization). While these methods have been successfully used as effective strategies to improve the solution of ill-posed inverse problems, they may not provide accurate solutions where a simple structural assumption can be defined for features with more complex geometry.

Objectives

The ensemble Kalman filter (EnKF) has recently been introduced to reservoir engineering literature as a promising history matching technique. It is easy to implement, provides considerable flexibility for describing reservoir model uncertainty, and supplies valuable information about reservoir performance prediction uncertainty. Among the limitations of the EnKF is its covariance-based (second order) model updating scheme that restricts its application to estimate discrete geological objects that are not amenable to covariance-based descriptions. When the standard EnKF implementation is used to update facies permeability values in each grid block (Fig. 1a), the connectivity between the existing features is not preserved even when facies description is parameterized to encourage continuity.

In this project, by using the (Continued on page 6)
In this project, by using the EnKF to generate a probability map to describe the spatial distribution of facies, we are developing a more consistent approach for incorporating dynamic flow measurements into multipoint pattern simulation with the Single Normal Equation SIMulation (SNESIM) algorithm.

**Future Work**

We are currently working to advance the implementation of our approach to deal with uncertainty in the training image that is used for pattern simulation and to address some of the limitations of the EnKF-based implementation of our algorithm.
**Sustainable Carbon Sequestration**

**Introduction**

Concerns that CO₂ emissions from the combustion of fossil fuel are causing global climate change have led to research that focuses on various ways in which CO₂ can be captured, sequestered and stored permanently in deep saline aquifers. The majority of CO₂ produced in the US comes from coal-fired power plants which account for about 50% of the electricity generation. At the rate in which CO₂ is produced from a typical power plant, it will require multiple injection wells, and each well will have a finite injection well area.

**Objectives**

Bulk CO₂ injection in a finite volume increases the pressure of the aquifer. To avoid breaching the aquifer seal, the injection well pressure must not exceed the formation fracture pressure. The result is a need for many wells and a prohibitively large aquifer area. Alternatively, it may be possible to avoid pressurizing the aquifer area and increase CO₂ storage efficiency by producing the same volume of brine as is injected as CO₂. This transforms the problem from CO₂ storage to water handling.

This study will investigate options for CO₂ storage management, including evaluating the feasibility of desalinating produced brine.

**Approach**

Previous studies have addressed issues related to sequestration of CO₂ in closed aquifers and the risk associated with aquifer pressurization. In this study, we will produce brine to relieve the pressure in the aquifer. First, we begin by extending known (waterflooding) conceptual models to apply to the CO₂/brine displacement process. This will help in the determination of well completion geometries, spacing, and flow rates that optimize CO₂ storage efficiency. Next, we will extend the work of Anchliya, 2009, such that the brine injector will inject saturated brine from the desalination process. Anchliya intended that injected brine would help curtail CO₂ breakthrough while increasing CO₂ trapping, as seen in Fig. 1. The conceptual models will be calibrated using rigorous numerical models. For this work, it will also be the mechanism to handle saturated brine from the desalination process.

We will evaluate the economic feasibility of CO₂/brine displacement with and without saturated brine injection. Finally, insights gained from the conceptual modeling phase will be used to develop optimization methods for improving CO₂ sweep efficiency.

**Significance**

The significance of this approach lies in its potential advantages over processes currently envisioned. Aquifer pressurization that may lead to breaching the integrity of the reservoir seal is avoided, and the CO₂ storage efficiency is increased compared to bulk CO₂ injection.
Related Publications


Newsletter Information

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