Assignment and Calibration of Relative Permeability by Hydrostratigraphic Units: A Novel Approach for Multiphase Flow Analyses

Case Study: CO_2-EOR Operations at the Farnsworth Unit, Texas

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Abstract

Among the most critical factors for geological CO_2 storage site screening, selection and operation is effective simulation of multiphase flow and transport. Relative permeability is probably the greatest source of potential uncertainty in multiphase flow simulation, second only to intrinsic permeability heterogeneity. The specific relative permeability relationship assigned greatly impacts forecasts of CO_2 trapping mechanisms, phase behavior, and long-term plume movement. A primary goal of this study is to evaluate the impacts and implications on CO_2-EOR model forecasts of different methods of assigning relative permeability relationships.

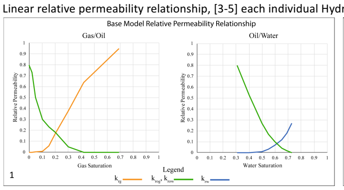
We applied a novel approach to assigning relative permeability relationships in numerical models. In previous research, most models assign relative permeability functions on the basis of geologic formation or rock type. In this study, we assign and calibrate relative permeability by hydrostratigraphic units, extending the seminal work of Maxey (1964) to multiphase flow. Ongoing work by the SWP has identified distinct regions that are believed to exhibit similar flow characteristics using the Improved Hydraulic Flow Units (IHFU) method. Core from each of these flow regions was scanned by micro-computer-tomography (micro-CT) and Mercury Intrusion Capillary Pressure (MICP) measurements were completed. Specific, constrained relative permeability relationships were assigned to each hydrostratigraphic unit. Results of forward simulations with the newly-calibrated models will be compared to those of existing model as well as a wide range of different relative permeability relationship.

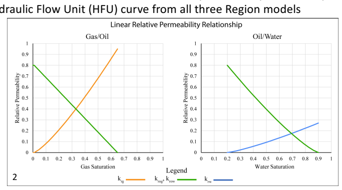
The study site is the Farnsworth Unit (FWU) in the northeast Texas Panhandle, an active CO_2-EOR operation. The target formation is the Morrow 'B' Sandstone, a clastic formation composed of medium to course sands. The study was undertaken as part of the Southwest Regional Partnership on Carbon Sequestration (SWP) under Award No. DE-FC26-05NT42591.

Relative Permeability Relationships

Two Approaches

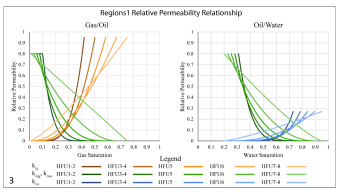
1. Single Relative Permeability curve assigned to the whole model domain: [1] Morrow Sandstone relative permeability relationship, [2] Linear relative permeability relationship, [3-5] each individual Hydraulic Flow Unit (HFU) curve from all three Region models

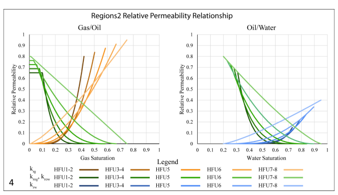


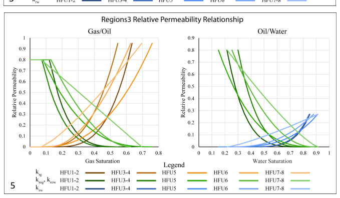


Hydraulic Flow Unit (HFU) relative permeability curves

- [3] Region1 curves vary the curve parameter lambda and the saturation end-points
- [4] Region2 curves vary the curve parameter lambda, the saturation end-points, and the relative permeability end-points
- [5] Regions3 curves vary the curve parameter lambda and the saturation end-points were determined from mercury intrusion capillary pressure measurements for each of the Hydraulic Flow Units (HFU)





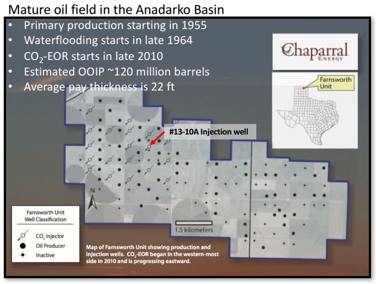


Model Domain

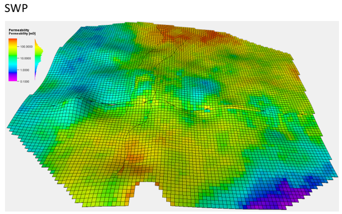
Farnsworth Unit, Ochiltree County, Texas

Mature oil field in the Anadarko Basin

- Primary production starting in 1955
- Waterflooding starts in late 1964
- CO_2-EOR starts in late 2010
- Estimated OOIP ~120 million barrels
- Average pay thickness is 22 ft

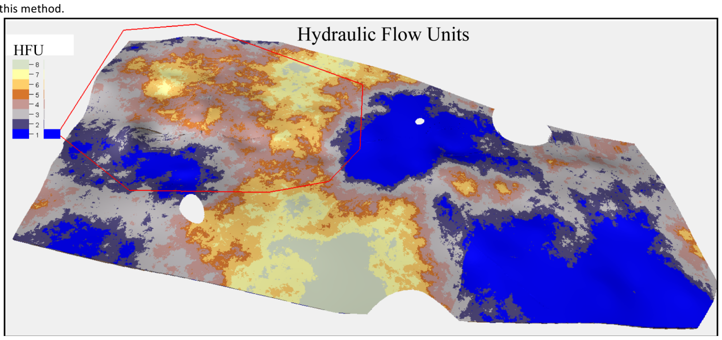


Permeability distribution in the simulation model. This distribution was used to create the HFU relationship by the SWP



Relative Permeability assignment by hydrostratigraphic units.

Unique hydrostratigraphic units were delineated as Hydraulic Flow Unit (HFU) where the properties that control fluid flow are internally consistent but distinct from other rock units. The Winland R35 method was used to identify the HFUs by providing a means of correlating porosity to permeability by assuming that when a sample is 35% saturated during a MICP test continuous flow paths are established. These flow units are then assigned a relative permeability curve and forward simulations were carried out to elucidate the influence of this method.

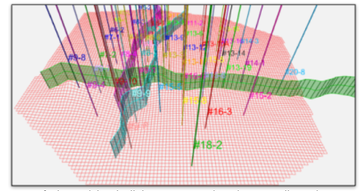


Hydraulic Flow Units (HFU) map of the entire reservoir showing the simulation model domain outlined in red. Hydraulic Flow Units were identified by D. Ross-Cross, W. Ampomah et al. (2016) (SPE-180375-MS) and used for the five grouped saturation regions in the simulation models; HFU1-2, HFU3-4, HFU5, HFU6, HFU7-8.

Numerical Model

Petrel E&P Software Platform

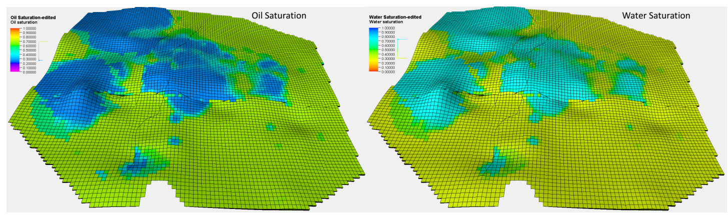
- 3-D Mesh creation – 103x95x4 (x,y,z) with 33,756 active cells
- Grid properties creation – permeability & porosity distribution
- Initial conditions assignment – Water saturation, Oil saturation, and Pressure
  - INCON data from history matched water flood model
- Water Alternating Gas (WAG) schedule for 22 injection wells – pure CO_2 used as gas stream
- Bottom hole pressure limits (2400 psi) for 35 production wells
  - Wells shut when water cut is above 98%



FWU faults model with all the injection and production wells used in this study. Faults are not barriers to flow in this model.

Initial Conditions

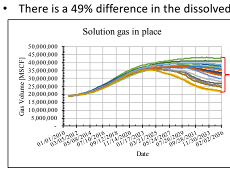
Initial oil saturation and water saturation was derived from a history matched primary production and waterflooding simulation.

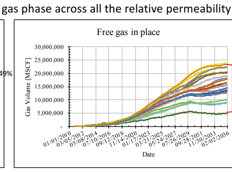


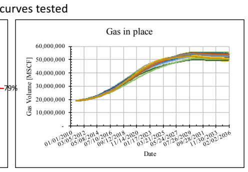
Results

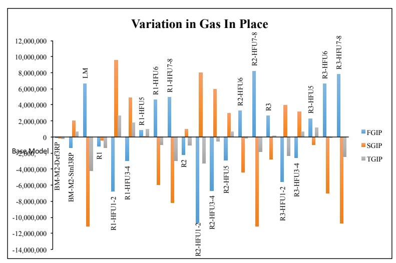
Gas In Place, free gas and dissolved gas

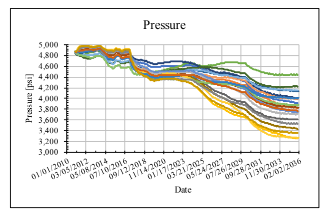
- The total amount of stored CO_2 predicted is between 3.0 million tons and 3.4 million tons across all of the curves studied
- The Regions3 model predicts 14% more CO_2 as a mobile phase and 8% less dissolved phase when compared to the Base Case
- The three HFU regions models (Regions1, 2, 3) show a 26% variance in free gas in place and only a 3% variation in the total gas in place
- There is a 79% difference in the volume of free CO_2 predicted across all relative permeability curves tested
- There is a 49% difference in the dissolved gas phase across all the relative permeability curves tested





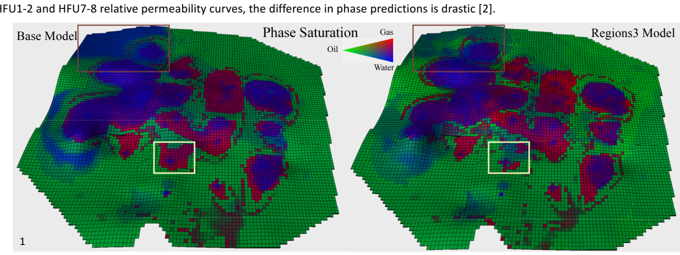


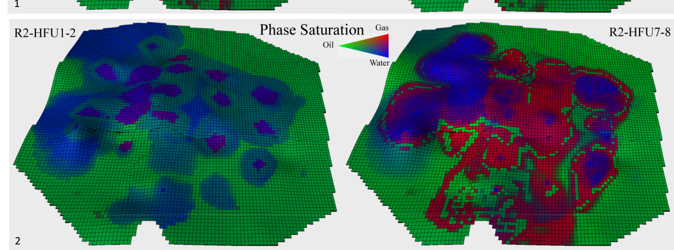




Three-phase saturation maps at the end of the simulation (20 years of CO_2-EOR)

The Base Case and Regions3 models had very similar pressure profiles but different CO_2 phase distribution, oil production, and gas production. The yellow and brown boxes highlight areas of significant variation between the Base Model and the Regions3 Model [1]. The CO_2 plumes around each of the injection wells in the Regions3 model show a lot of variation from the Base Case model, with some wells predicting far less gas phase, especially in the South-central portion of the reservoir. When the end cases are evaluated, Region2 model HFU1-2 and HFU7-8 relative permeability curves, the difference in phase predictions is drastic [2].





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