Determining the long-term fate of CO\textsubscript{2} storage associated with an enhanced oil recovery project


University of North Dakota Energy & Environmental Research Center
15 North 23rd Street, Stop 9018, Grand Forks, ND 58202-9018

Abstract

The monitoring and modeling technologies required for carbon dioxide (CO\textsubscript{2}) enhanced oil recovery (EOR) operations have been well proven by many existing projects. However, the situation is substantially different when the operational phase ends and the site closure/postclosure phase is initiated (wells are plugged and abandoned and natural hydrodynamic conditions return). Accurate forecasting of the long-term fate of injected CO\textsubscript{2} becomes a critical part of avoiding unintended CO\textsubscript{2} migration. Although various studies have been conducted to predict the long-term migration of CO\textsubscript{2} in saline formations, little work has been done to investigate how CO\textsubscript{2} interacts with the residual oil and formation water in the long run after EOR operations. Compared with saline aquifers for dedicated CO\textsubscript{2} storage, the conditions in oil reservoirs are significantly more complex because of the continuing interaction between CO\textsubscript{2} and hydrocarbons in the reservoir. The composition of residual oil changes with time, and such change may influence the distribution of CO\textsubscript{2} saturation and pressure across the reservoir.

Efforts have been undertaken to determine the long-term fate of CO\textsubscript{2} injected into an oil reservoir under EOR operations in Montana. Field data indicated that the movements of reservoir fluids are sensitive to reservoir heterogeneity. Permeability logs were created for each well in the study area via a neural network using core porosity/permeability and bulk density logs. Multiple-point statistics were then applied to build a geologic model which allowed a realistic representation of connectivity and compartmentalization of sand bodies to better explain and predict the migration of fluids in the reservoir. Based on the geologic model, a compositional reservoir simulation model using an equation-of-state (EOS) fluid description was developed to simulate multiphase, multicomponent flow and transport coupled with CO\textsubscript{2} mass transferring between phases (oil, water, and gas). Historical production data and 4-D seismic survey interpretations were used to calibrate the model, which was then used to predict the long-term CO\textsubscript{2} trapping (1000 years) in the reservoir. Results showed that even when there is no pressure differential induced within the reservoir (e.g., no injection or production), CO\textsubscript{2} will still migrate through porous media as a result of the effects of buoyancy between CO\textsubscript{2} and the native formation fluids. As opposed to CO\textsubscript{2} solubility in a saline aquifer, CO\textsubscript{2} solubility in oil is much greater (≥5 times) than that in water based on the fluid properties and reservoir conditions in the study area. The findings indicate that CO\textsubscript{2} EOR is not only a promising operational approach for oil production, but also an attractive option for long-term CO\textsubscript{2} storage. The distribution of the CO\textsubscript{2} saturations indicates that the migration process is slow because of the mechanisms of residual and solubility trapping. To ensure the safety of CO\textsubscript{2} storage in the reservoir for such a long
period, a 1-D mechanical earth model was also constructed based on the data from a monitoring well in order to analyze wellbore stability and horizontal stresses around the wellbore.

The results of this study indicate that CO₂ can be effectively trapped in the reservoir and will not migrate beyond the boundaries of the oil reservoir during a long period after the completion of CO₂ EOR operations.