Analyzing the Performance of Closed Reservoirs Following CO₂ Injection in CCUS Projects

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Abstract

Carbon dioxide (CO₂)-assisted enhanced oil recovery (EOR) is emerging as an attractive option for moving carbon capture and storage (CCS) forward in the near term. Such a strategy enables much of the necessary carbon capture and pipeline infrastructure to be installed during the EOR life cycle while producing additional oil and revenue from depleted oil fields. When executed synergistically, CO₂-assisted EOR and CCS are referred to as Carbon Capture, Utilization, and Storage (CCUS), which can serve as a bridge technology prior to establishment of market conditions for commercial deployment of CO₂ sequestration. This concept of CCUS is being actively promoted by the U.S. Department of Energy through its network of regional carbon sequestration partnerships. One of these partnerships, the Midwest Regional Carbon Sequestration Partnership (MRCSP), is currently investigating various reservoir characterization, modeling, and monitoring technologies related to CCUS in conjunction with CO₂-EOR operations in multiple depleted pinnacle reef oil fields in Michigan, USA.

The development of a methodology for analyzing the performance of these closed reservoirs, i.e., quantification of injectivity and storage capacity using primary production and CO₂ injection rate/pressure data, is the subject of this paper. Our strategy is to use a numerical model that represents a typical depleted reef reservoir with simulated primary production followed by CO₂ injection. Conventional pressure-transient analysis, injectivity-index analysis and material balance analysis approaches from petroleum reservoir engineering practice are then applied to determine the extent to which these approaches (or modifications thereof) can be combined to create a suite of rapid performance assessment tools. These insights can be subsequently applied for the routine analysis of field data.

The numerical model is based on 2-D radial geometry representing a typical pinnacle reef reservoir that is ~1300 ft wide and ~300 ft thick with a well at the center that acts as the producer during the primary production period as well as injector during the CO₂ injection period. The medium permeability reservoir zone occupies the middle of ~130 ft of the model domain, overlain by a very low-permeability cap rock and underlain by a low-permeability water column. The original oil in place is ~3 million stock tank barrels. The model is initialized at a pressure of ~2900 psi at a reference depth of ~4400 ft. It is produced for a period of 10 years at a constant bottom-hole pressure of ~100 psi, during which approximately 50% of the original oil in place is produced. Thereafter, CO₂ is injected at a constant rate of 500 metric tons per day using a gradual ramp-up schedule, viz.: 1 month injection and 2 week shut-in, 2 month injection and 3 week shut in, 3 month injection and 4 week shut in, and 3 additional periods of 6 month injection and 4 week shut in. Results from a compositional reservoir simulator (CMG-GEM) corresponding to this production-injection schedule are captured in terms of raw data such as pressure versus time and radial distance. Simulator results are also processed in terms of computed variables such as total fluid
mobility (i.e., sum of effective permeability divided by viscosity for all phases) and total compressibility (i.e., sum of saturation weighted phase compressibilities) versus radial distance at the end of each injection period.

We first analyse the pressure fall-off data from each of the shut-in periods using standard pressure transient analysis methods. These methods typically assume single-phase reservoir conditions, although the presence of a multi-phase system with phase boundaries can be handled using a radially-composite system conceptualization (i.e., where a near-wellbore “inner” region has different mobility and compressibility values compared to a far-field “outer” region). Such a conceptualization fits the simulated data reasonably well, and the interpreted total mobility and compressibility values for the inner and outer regions are consistent with the simulator outputs. This suggests that a conventional pressure transient analysis approach can be applied to the pressure data following CO₂ injection, and we provide guidelines as to how to interpret the effective mobility and compressibility values vis-à-vis intrinsic reservoir properties (e.g., permeability, porosity).

Next, we examine time history of the injectivity index, calculated as injection rate divided by the pressure buildup from ambient conditions. During the transient period (i.e., before boundary effects are felt), we find that the injectivity index is proportional to the effective mobility, whereas during the boundary-dominated period, the injectivity index is proportional to total compressibility. Thus, the injectivity index analysis can be used to cross-check the pressure transient analysis results regarding the total mobility of the system (i.e., the effective conductivity to CO₂ injection) and indicate the onset of boundary effects.

Finally, we apply a material balance analysis, where the objective is to relate the voidage created in the reservoir from primary oil and dissolved gas production to the reservoir volume that can be occupied by CO₂. We show that a material balance formulation assuming negligible remaining formation gas and negligible swelling of CO₂-dissolved crude oil is capable of generating results that agree with the simulated values of average pressure buildup versus cumulative CO₂ volume injected. This provides a simple and practical approach for estimating CO₂ storage capacity in a depleted oil reservoir that does not require a numerical simulator.

In summary, we present a suite of tools for estimating injectivity and storage capacity for CO₂ injection into depleted oil fields. These approaches are based on standard reservoir engineering workflows (or modifications thereof) that are based on the analysis carried out in this study for a synthetic simulated dataset.

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