Abstract

The Plains CO2 Reduction (PCOR) Partnership, through the Energy & Environmental Research Center, is collaborating with Petroleum Technology Research Centre (PTRC) in site characterization, risk assessment, public outreach, and monitoring, verification, and accounting activities at the Aquistore project. The Aquistore project is a carbon capture, utilization, and storage (CCUS) project situated near Estevan, Saskatchewan, Canada, and the U.S.–Canada border. The project is managed by PTTRC and will serve as a buffer storage of carbon dioxide (CO2) from the SaskPower Boundary Dam CCS project, the world’s first commercial-scale postcombustion CCS project from a coal-fired electric generating facility. To date, an injection well and an observation research well (~152 m apart) have been drilled and completed at the Aquistore site, with injection anticipated to begin in fourth quarter 2014. Using a combination of site characterization data provided by PTTRC and independent studies, the PCOR Partnership has constructed a static geologic model to assess the potential volumetric storage capacity of the Aquistore site and provide the foundation for dynamic simulation of the dynamic storage capacity. The results of the predictive simulations will be used in the risk assessment process to help define an overall monitoring plan for the project and to assure stakeholders that the injected CO2 will remain safely stored at the Aquistore site.

The deep saline system targeted for storage comprises the Deadwood and Black Island Formations, the deepest sedimentary units in the Wilcox Basin. At over 3100 m below the surface, this saline system is situated below most oil production and potash-bearing formations in the region and provides a secure location for the storage of CO2. Characterization data acquired from the Aquistore site for these formations include petrophysical core data, a comprehensive logging suite, and 3-D seismic data for structural control.

Approach

The workflow for model development and optimization included 1) petrophysical log analysis, 2) stratigraphic correlation and structural analysis, 3) data analysis, 4) petrophysical modeling, 5) uncertainty analysis, and 6) model upsampling and grid refinement. Total porosity and net-to-gross volumes were calculated on 15 wells using the neutron density and gamma ray methods, respectively. Porosity results were also calibrated to data measured from routine core analysis data performed on whole and sidewall core. The shale volume derived from the petrophysical analysis was used to divide the model into 12 trussable zones, including six sand units (two in the Black Island and four in the Deadwood Formation) and six shale units throughout the regional study area.

To evaluate the targeted saline system, and thus its stability as a potential sink, the geologic model was used as the framework for an assessment of the dynamic storage capacity of the system. Through the dynamic simulation effort, two main objectives were established for this project: 1) assess the dynamic storage capacity of the saline system and 2) assess the risk by simulating the reservoir performance during CO2 injection and postinjection. To address these objectives, the refined model (339 km2) was used to determine the injectivity of study area through the various injection rates and periods to investigate the timing of CO2 breakthrough in the observation well and near wellbore CO2 movement. All of the dynamic simulations were performed using Computer Modelling Group Ltd.’s (CMG) Commercial & Unconventional Reservoir Simulator (GEM) (www.cmgl.ca/) on a 184-core, high-performance parallel computing cluster.

Results

Based on the simulation results, the storage of CO2 in the study area using the existing two well configuration is feasible, depending on the volume of CO2 available from the Boundary Dam power plant. The static CO2 capacity for the local-scale model ranges from 8.4 to 27.1 million tonnes CO2 for the PI and P95 confidence levels, respectively. The maximum simulated injectivity for the current injection well is 0.73 Mt/yr based on the geological characterization of the study area. Based on these simulation results, the maximum storage potential of the Aquistore site with one injection well is approximately 3.6 Mt after 65 years. However, this can be improved based on optimization operations such as multiple injection wells, formation water extraction, and horizontal injection. The larger capacity value obtained through the dynamic modeling suggests that the storage coefficient used in the static approach may be too low and that the CO2 will successfully interact with a larger percentage of the system.

Based on the simulated CO2 injection cases, the earliest CO2 breakthrough to the observation well may happen in as few as 15 days with a 0.79 Mt/yr injection rate. The breakthrough time at the observation well may be extended to 1 month if the injection rate is reduced to 0.3 Mt/yr. The simulated overall CO2 breakthrough in the other reservoir zones occurred after about 3 months of injection with the low injection rate, and this breakthrough time was reduced to about 45 days at the high injection rate. The simulated pressure response in all cases indicated that the system was locally pressure-limited in the open-system cases, as an injection rate of 1 Mt/yr was not achieved. The pressure in the system was also limited by boundary conditions, which resulted in a much lower injection rate.

References