INVESTIGATION OF GEOCHEMICAL INTERACTIONS OF CARBON DIOXIDE AND CARBONATE FORMATION IN THE NORTHWEST MCGREGOR OIL FIELD AFTER ENHANCED OIL RECOVERY AND CO_2 STORAGE

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Injection of carbon dioxide (CO_2) for the purpose of enhanced oil recovery is widely regarded as one of the key commercial applications of geological storage that will provide valuable insight into large-scale projects aimed at reducing CO_2 emissions to the atmosphere. The Plains CO_2 Reduction Partnership, one of the seven U.S. Department of Energy National Energy Technology Laboratory Regional Partnerships, is conducting a project in the Northwest McGregor oil field in North Dakota to determine the effects CO_2 will have on the productivity of the reservoir, wellbore integrity, and the carbonate formation into which CO_2 was injected. The method used in this project is "huff 'n' puff" whereby 440 tons of supercritical CO_2 was injected into a well over a 2-day period and allowed to "soak" for a 2-week period. The well was subsequently put back into production to recover incremental oil. The purpose of this paper is to outline the approach and current observations for the numerical modeling and laboratory simulations of potential geochemical reactions in order to evaluate the short-term risks for operations (e.g., porosity and permeability decrease) and long-term implications for CO_2 storage via mineralization.

Mineralogy of the reservoir was determined using well logs, traditional core sample analysis with x-ray diffraction, x-ray fluorescence, and QEMSCAN® techniques. The integrative mineralogical analysis was performed utilizing linear program normative analysis. Using the results of these analyses, the mineral phases selected for model inputs were anhydrite, calcite, dolomite, illite, K-feldspar, and traces of pyrite. A pressurized bottom-hole fluid sample was also collected, and its composition was determined. The results of this fluid sample were also used as input parameters for the model.

Modeling was performed using PHREEQC and Geochemist Workbench software in order to determine the most likely geochemical interactions and predict changes to in situ fluid properties. The Computer Modeling Group Ltd. GEM simulator was utilized for the creation of a 2-D cross-sectional model for reactive transport evaluation. The modeling results were compared to laboratory experiments where core samples collected from several intervals of the Mississippian Madison Group of the Williston Basin (North Dakota, USA) were exposed for a period of 4 weeks to pure supercritical CO_2 at 2250 psi (155 bar) and 158°F (70°C) in 10 wt% NaCl synthetic brine conditions.

Results of numerical modeling suggest that the rocks within the already acidic environment (ph < 4.5) of the Northwest McGregor oil field should not experience any significant changes in mineralogy, especially in the near term, which correlates with postinjection field geochemical analysis. It is predicted that carbonate minerals (primarily, calcite) will dissolve near the injection point and traces of anhydrite or gypsum will precipitate on the edges of the CO_2 plume. This prediction was also supported by the laboratory simulation, although other significant mineralogical changes were also observed in samples after exposure to supercritical carbon dioxide at reservoir conditions. These observations demonstrate the importance of correlating initial geochemical modeling with the laboratory results for more consistent and accurate predictions at the field-scale modeling stage. Finally, the numerical modeling predicts insignificant changes in porosity and permeability near the perforation zone as a result of calcite dissolution, which favors current and future operations at the site.