NORTHWEST MCGREGOR FIELD CO_2 HUFF 'N' PUFF: A CASE STUDY OF THE APPLICATION OF FIELD MONITORING AND MODELING TECHNIQUES FOR CO_2 PREDICTION AND ACCOUNTING

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The Plains CO_2 Reduction (PCOR) Partnership has conducted field and laboratory activities to determine the effects of injecting carbon dioxide (CO_2) into an oil field in the United States portion of the Williston Basin. These activities were conducted as part of Phase II of the U.S. Department of Energy's Regional Carbon Sequestration Partnership program. The purpose of the activities was to evaluate the potential dual purpose of CO_2 storage and enhanced oil recovery (EOR) in carbonate rocks deeper than 2440 m. Activities were conducted to 1) establish the baseline geological characteristics of the injection site, 2) determine the effect that CO_2 has on the ability of the oil reservoir to store CO_2 and produce incremental oil, and 3) evaluate the ability of Schlumberger's Reservoir Saturation Tool (RST) and Vertical Seismic Profile (VSP) technologies to detect a small-volume CO_2 plume in deep carbonate reservoirs.

While the CO_2-based EOR operations at the Weyburn and Midale fields in Saskatchewan, Canada, are good examples of economically and technically successful injection of CO_2 for simultaneous EOR and sequestration, the depths of injection in those fields are relatively shallow (ca. 1400 m) and not necessarily representative of many large Williston Basin oil fields. One of the primary goals of the PCOR Partnership Phase II Williston Basin Field Validation Test was to evaluate the effectiveness of CO_2 for EOR and sequestration in oil fields at depths greater than 2440 m. To achieve that goal, a CO_2 huff 'n' puff (HnP) test was conducted on a well that is currently producing oil from the Mission Canyon Formation at a depth of approximately 2454 m in the Northwest McGregor oil field in Williams County, North Dakota. During the test, 440 tons of CO_2 was injected into a single well and allowed to "soak" for 2 weeks, after which the well was put back into production. Unique elements of the Northwest McGregor Mission Canyon reservoir as compared to other HnP operations in the literature, include the following: 1) at a depth of 2454 m, it would be among the deepest; 2) pressure (20.7 Mp) and temperature (82° C) would be among the highest for a HnP; and 3) most HnPs in the literature are in clastic reservoirs, while the Northwest McGregor Mission Canyon reservoir is a carbonate reservoir.

Using a petrophysical model of the reservoir, iterative dynamic simulations of the fate of CO_2 in the target reservoir were developed. Characterization and modeling in support of dynamic simulations included normalizing all logs and performing an error-minimizing stochastic multimineral petrophysical analysis. Neural networks were used to produce matrix permeability to gas and liquids, vertical permeability to gas, irreducible fluid saturations, fracture intensity, and missing zones or logs in the study area. Petrophysical results were verified with Qemscan®, x-ray diffraction, petrographic analysis, and cutting and core descriptions. This produced the main components for a macrofacies/microfacies and fluid model, with the major lithofacies being limestones, dolomites, and anhydrites. To gain a regional understanding of the producing interval, large-scale trend modeling used a traditional sequential indicator and Gaussian simulations, while small downscaled injection models used discrete and continuous multiple point statistics guided by inverted seismic data. The dynamic response of the injection zone was evaluated for changes over the course of the project using two-dimensional VSP projected into three dimensions, temporally resolute RST logs in sigma mode, and produced fluid analysis that were used to history-match fluid and gas saturations.

The static and dynamic modeling activities were conducted in an iterative manner, with each iteration based on the acquisition of new data over the course of the baseline characterization, injection, and postinjection activities. These simulations were compared to actual postinjection reservoir conditions as monitored over the duration of the study period. The simulations demonstrated the importance of considering the effects of fracture networks on CO_2 movement when predicting CO_2 mobility and fate. The results of the RST and VSP indicated that the CO_2 penetrated approximately 300 feet horizontally and 50 feet vertically into the reservoir. Productivity of the oil well was observed to more than double over the course of a 3-month production period, increasing from a baseline oil production rate of 1.5 stock tank barrels (STBs) a day to 3 to 7 STBs a day. Overall, the results of the field demonstration indicate that 1) CO_2-based HnP operations may be a viable option for EOR in deep carbonate oil reservoirs and 2) the RST and VSP technologies may be effective MVA tools for deep carbonate oil reservoirs.