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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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Abstract

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 U.S. 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 2400 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 2400 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 2450 m in the Northwest McGregor oil field in Williams County, North Dakota. During the test, 440 tonnes 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 2450 m, it would be among the deepest, 2) pressure (approximately 20 MPa) and temperature (approximately 80°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.

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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 analyses 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 indicated that the CO_2 migrated approximately 15 meters vertically into the reservoir. The results of the VSP provided valuable data regarding the horizontal nature of the Mission Canyon reservoir and sealing lithofacies identified by the RST and core studies, but its ability to identify a CO_2 plume within the reservoir was determined to be inconclusive. 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, 2) the RST and VSP technologies are effective tools for baseline characterization, and 3) the RST may be an effective MVA tool for deep carbonate oil reservoirs, but the ability of the VSP technology to identify small volumes of CO_2 in a deep carbonate reservoir could not be conclusively determined.

Keywords: CO_2 storage; EOR; monitoring

Introduction

The Plains CO_2 Reduction (PCOR) Partnership is working to evaluate the potential for geologic sequestration of carbon dioxide (CO_2) in a deep carbonate reservoir for the dual purpose of CO_2 sequestration and enhanced oil recovery (EOR). Phase I studies indicated that Williston Basin oil fields may have the capacity to store over 500 million tonnes of CO_2 as part of CO_2 flood EOR operation [1]. As part of the PCOR Partnership Phase II Williston Basin field demonstration program, activities to improve understanding and develop technologies and approaches for CO_2 EOR and monitoring, verification, and accounting (MVA) have been conducted at the Northwest McGregor oil field in Williams County, North Dakota, USA. The goals of the activities at Northwest McGregor are to 1) evaluate the technical and economic viability of CO_2 injection in carbonate oil reservoirs at depths greater than 2400 m, 2) determine the effectiveness of the CO_2 huff 'n' puff (HnP) approach to stimulate oil recovery from individual mature wells in the PCOR Partnership region, and 3) test the ability of two specialized geophysical reservoir characterization techniques (Schlumberger's Reservoir Saturation Tool [RST] and Vertical Seismic Profile [VSP]) with respect to the identification of relatively small amounts of CO_2 in a deep carbonate reservoir. The results of the Williston Basin field demonstration at the Northwest McGregor oil field provide stakeholders with previously unavailable information to support the deployment of CO_2 HnP as a means of improved oil recovery in the PCOR Partnership region and provide carbon capture and storage (CCS) operators with previously unavailable information regarding the deployment of RST and VSP technologies as part of an MVA plan.

Many oil fields being considered for CO_2-based EOR operations in the Williston Basin occur at depths greater than 2400 m. 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 2400 m. To achieve that goal, a CO_2 HnP test was conducted on a well (formally named the E. Goetz #1 well) that is currently producing oil from an interval of the Mississippian-aged Mission Canyon Formation at a depth of approximately 2450 m in the Northwest McGregor oil field (Figure 1). As an initial pilot-scale HnP test, approximately 440 tonnes of CO_2 was injected into a single well, and allowed to "soak" for 2 weeks, after which time the well was brought back into production, allowing the flow of incremental oil, water, and gas (primarily CO_2). Unique elements of the Mission Canyon Formation within the Northwest McGregor oil field with respect to the application of a CO_2 HnP operation, as compared to other HnP operations in the literature, include the following: 1) at a depth of 2450 m, it would be among the deepest, 2) pressure (20.7 MPa) and temperature (93°C) would be among the highest, and 3) most HnPs in the literature have been conducted in clastic reservoirs, whereas the Northwest McGregor field is a fractured carbonate (limestone) reservoir.

While the use of monitoring procedures that are already mandated as part of existing regulations governing oil field operations and/or underground injection control should be the core of any MVA plan, the application of specialized monitoring technologies may be appropriate at storage locations where their use is both technically valuable and cost-effective. The Northwest McGregor HnP test

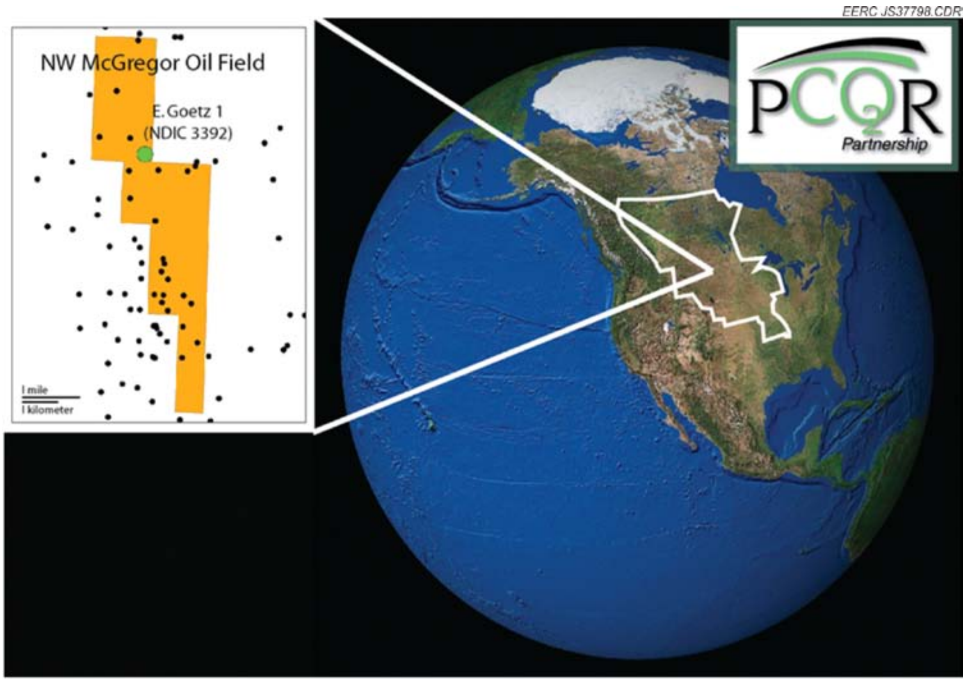

Figure 1 Map of the Northwest McGregor oil field.

offered a unique opportunity to test two specialized geophysical technologies, Schlumberger's RST and VSP, in a deep carbonate reservoir environment. Positive results from the testing of those tools do not necessarily mean that they should or even could be successfully used at all CCS sites, but rather provide the operators of a CCS project with a basis from which to make an informed judgment as to whether or not RST and/or VSP may be valuable components of a cost-effective MVA plan.

Description of Northwest McGregor MVA Plan

A detailed description and discussion of the MVA activities conducted as part of the Northwest McGregor HnP project are provided in Sorensen et al. [2]. MVA program activities that resulted in the determination of baseline conditions include geologic and hydrogeologic characterization at various scales, characterization of the Northwest McGregor reservoir, the determination of geomechanical and geochemical properties of key rocks in the reservoir/seal system, and evaluation of wellbore integrity issues. Field-based elements of the MVA program include the introduction of a tracer and data collection (i.e., formation fluid sampling and analysis, reservoir dynamics monitoring) from the injection/production well and monitoring wells. Other key elements of the MVA program include documentation of the permitting process and regulatory framework for the project, determination of material balance based on the collected field data, and an observational study of the effectiveness of CO_2-based HnP with respect to improving oil productivity. Generally speaking, monitoring activities were focused on the near-reservoir environment, including monitoring for leakage through cap rock, migration away from the intended zone of influence within the reservoir, and wellbore leakage. However, shallow groundwater wells in the vicinity of the Northwest McGregor HnP test were also tested before injection, during the operational phase of the project, and at the end of the project performance period to prove that the CO_2 injection program did not impact local groundwater resources. The results of the monitoring activities, which are presented and discussed in detail in Sorensen et al. [2] demonstrated that no statistically significant changes in monitored parameters were observed over the course of the project at any of the monitoring wells.

Application of RST and VSP at the Northwest McGregor HnP Test

The Northwest McGregor HnP test site offered a chance to test two specialized geophysical characterization technologies in a deep reservoir environment. The RST and VSP technologies, both owned and operated by Schlumberger Oilfield Services, were deployed before and after CO_2 injection operations. The Northwest McGregor Field allowed for testing of these technologies under conditions that are relatively unique. The depth of the reservoir meant that the downhole components of the technologies would be subjected to higher reservoir pressures and temperatures than are usually encountered for a CO_2 storage project. Also, the heterogeneity of the Mission Canyon Formation added a level of complexity to the system that further tested the capabilities of the technologies. The small amount of CO_2 injected into the reservoir and small footprint of the plume also pushed the documented lower threshold of CO_2 detection for the RST and VSP technology, which is useful when trying to delineate the edges of large plumes created by large-scale CCS projects.

The RST is a downhole geophysical tool that is deployed into the target well using a truck-mounted wireline system. The RST technology was deployed in the E. Goetz #1 well three times over the course of the Northwest McGregor HnP project: 1) before injection to establish baseline saturations of oil, water, and gas in the near wellbore reservoir environment; 2) approximately 72 hours after injection to determine the occurrence of CO_2 when it was at its maximum saturation in the near-wellbore reservoir environment; and 3) 129 days after the well was brought back into production. Figure 2 shows a comparison of results from those RST logging events. The results indicate that the

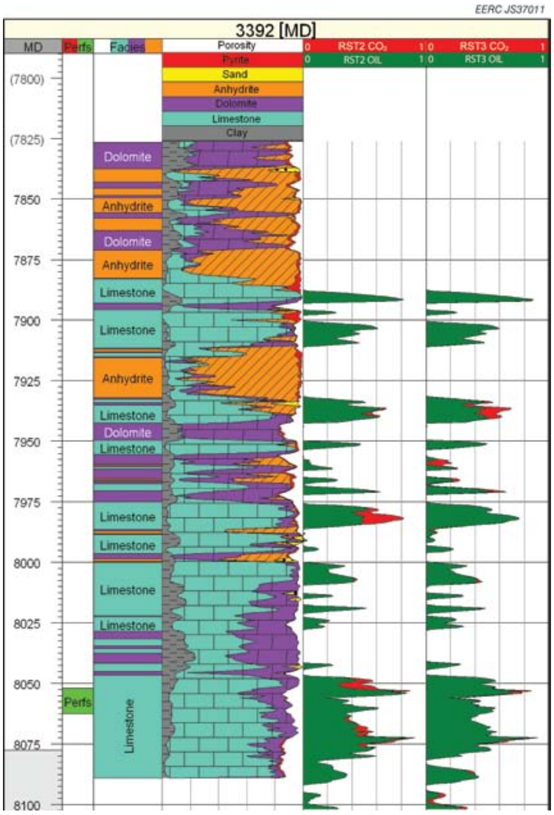

Figure 2 Comparison of results of three of the Northwest McGregor RST logging events. The RST log on the left represents fluid saturation approximately 48 hours after injection. The RST log on the right represents conditions approximately 3 months later. Red represents CO_2 saturation, while green represents oil saturation.

RST logging tool is able to clearly identify the zones within the near-wellbore reservoir into which CO_2 was injected and subsequently migrated. In the case of the Northwest McGregor reservoir, it appears that after injection, the CO_2 plume largely moved upward until it was blocked by the impermeable anhydrite bed at a depth of approximately 2417 meters. Some residual gas saturation appears to have migrated into and remained at levels below the perforated zone. This is interesting because it matches well with the vertical geometry of the plume that was predicted by the dynamic simulation that included the fracture network as part of the geologic model. These results indicate that the RST is capable of operating effectively in deep carbonate reservoir environments. Such results can be useful when determining the vertical migration of CO_2 in a reservoir. Additionally, when interpreted in conjunction with ultrasonic imager logs, caliper logs, and other wellbore integrity-related logs, these results may be particularly useful in identifying locations in the wellbore that may be acting as points of leakage.

The VSP technology couples the use of a downhole wireline acoustic monitoring tool with surface seismic sources to generate 2-D seismic maps of the target reservoir. In the case of the Northwest McGregor project, the seismic sources were provided by two vibe trucks located on opposite ends of a line approximately 914 meters from the target well. Each VSP survey event was conducted using multiple lines in different orientations (e.g., north–south, east–west) to facilitate the development of a 3-D view of the reservoir. The VSP technology was deployed twice over the course of the project: 1) before injection to establish baseline conditions in the reservoir environment and 2) 129 days after the well was brought back onto production. Figure 3 shows baseline characterization results from the VSP. Examination of the processed VSP data generated

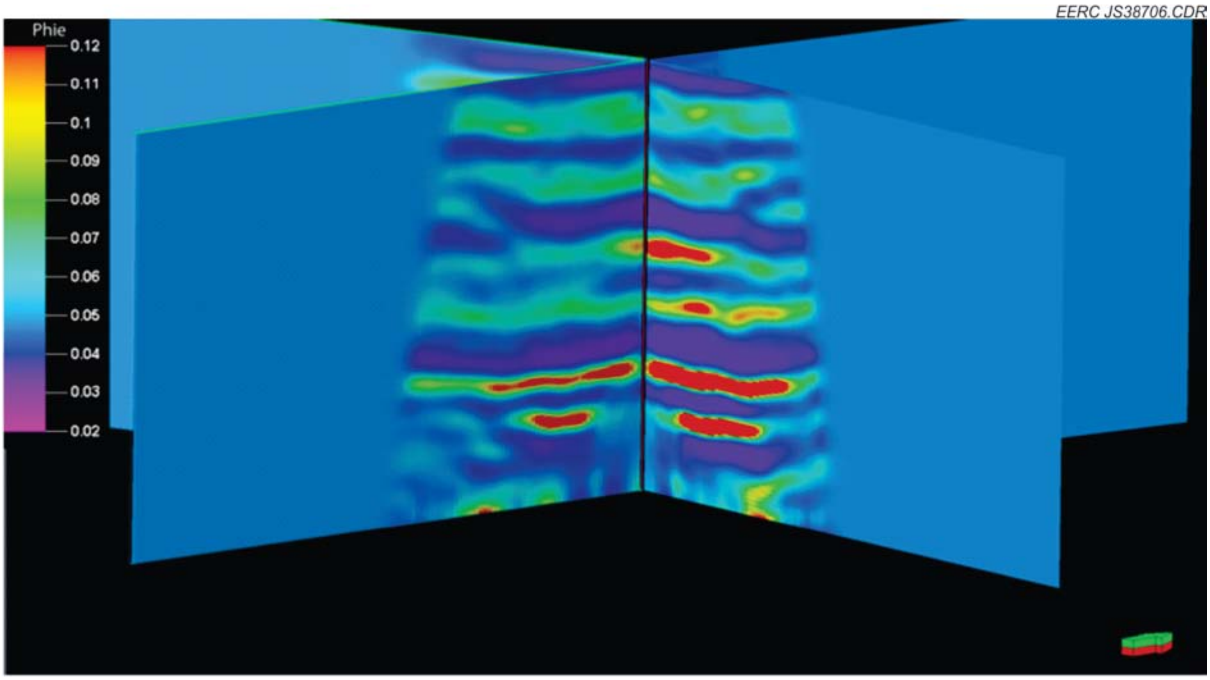

Figure 3 Results from the first VSP deployment showing distribution of key lithofacies.

by the two surveys showed that while there appears to be some observable difference in seismic reflectance in the reservoir between the baseline and postinjection runs, the difference is not significant enough to confidently conclude that the VSP was able to identify a CO_2 plume in the reservoir. The results of the VSP did provide invaluable data regarding the horizontal nature of the Mission Canyon reservoir and sealing lithofacies identified by the RST and core studies. In this sense, the VSP data enabled the development of a more accurate petrophysical model, which in turn supported history-matching efforts.

Northwest McGregor CO_2 Injection and Incremental Oil Production

The total amount of CO_2 injected into the Mission Canyon reservoir of the Northwest McGregor oil field was 440 tonnes, injected over 36 hours. The operational parameters of the injection are provided in Sorensen et al. [2]. After the injection phase of the HnP operation, the E. Goetz #1 well was shut in, and the injected CO_2 was allowed to soak for a period of 2 weeks. When opened, the E. Goetz #1 well proceeded to produce gas exclusively for approximately 2 hours before producing oil and water at a rate approximately 10 times greater than baseline (1.5 bbl/day oil). This high production, with a peak production rate of 20 barrels of oil per day, continued over the course of 5 days, during which the well was free-flowing (i.e., not on any type of pump). Because of scheduling conflicts on the part of the service rig providing support to the HnP project, the decision was made to install a pump into the producing well on the sixth day of the production phase. Unfortunately, the installation of the pump significantly restricted the flow of oil and water from the well, and while average daily production rates were two to three times higher than the original baseline production rate of 1.5 barrels of oil per day, oil production did not approach the very high rates achieved in the first few days of the production period. Table 1 provides key production statistics for the period of production.

Table 1 Key Production Statistics for the Northwest McGregor HnP Operation

	E. Goetz Baseline Production Statistics	HnP Production Statistics (averages) (July 6 through November 10, 2009)	Improved Recovery to Date
Oil Production Rate (not including downtime)	1.5 BOPD	3.3 BOPD	2.2×
Oil Cut	2.8%	6%	2.1×
% of Injected CO_2 Produced Back	NA	30%	NA

Conclusions

Over time, as carbon management becomes a greater component of mainstream society, carbon credit-trading markets will evolve and provide additional economic incentives for conducting large-scale CCS projects. Once oil resources at injection locations have become depleted, the development of robust carbon credit-trading markets will facilitate and ultimately support continued injection into saline formations as the second phase of CCS implementation. The establishment of carbon credits associated with geologic storage of CO_2 will require a robust yet cost-effective MVA plan for each injection project. The activities and results of the Northwest McGregor HnP project made several valuable contributions to the baseline characterization and monitoring components of MVA. In particular, the Northwest McGregor HnP project demonstrated the effectiveness of using the RST and VSP technologies to develop a detailed understanding of the vertical and horizontal nature of reservoir lithofacies—key components of accurate modeling. With respect to monitoring CO_2, the use of RST was demonstrated to be valuable, while the VSP results were inconclusive. The results generated at the Northwest McGregor field indicate that these technologies should be considered to be valuable additions to the characterization and/or MVA toolbox for future large-scale CCS projects.

Acknowledgment

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