PLAINS CO_2 REDUCTION (PCOR) PARTNERSHIP (PHASE II) – WILLISTON BASIN FIELD DEMONSTRATION, NORTHWEST MCGREGOR CO_2 HUFF 'N' PUFF – REGIONAL TECHNOLOGY IMPLEMENTATION PLAN (RTIP)

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Prepared for:

Andrea T. McNemar

U.S. Department of Energy
National Energy Technology Laboratory
3610 Collins Ferry Road
PO Box 880, MS P03D
Morgantown, WV 26507-0880

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Prepared by:

James A. Sorensen
Darren D. Schmidt
Steven A. Smith
Damion J. Knudsen
Edward N. Steadman
John A. Harju

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street North, Stop 9018
Grand Forks, ND 58202-9018

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EXECUTIVE SUMMARY

The Plains CO_2 Reduction (PCOR) Partnership has conducted field and laboratory activities to determine the effects of injecting carbon dioxide (CO_2) into a Williston Basin oil field. 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 8000 ft. 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 a deep carbonate reservoir.

While the CO_2-based EOR operations at the Weyburn and Midale fields in Saskatchewan 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. 4600 ft) 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 8000 ft. 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 8050 ft 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 onto 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 8052 ft, it would be among the deepest; 2) pressure (3000 psig) and temperature

(180°F) would be among the highest; and 3) most HnPs in the literature are in clastic reservoirs, while the Northwest McGregor Mission Canyon reservoir is a carbonate reservoir.

The dynamic response of the injection zone was evaluated for changes over the course of the project using the RST and VSP, pressure monitoring, and fluids analysis from the injection well and another nearby producing oil well. Using a petrophysical model of the reservoir, iterative dynamic simulations of the fate of CO_2 in the target reservoir were developed. Each iteration was 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 CO_2 mobility and fate are predicted. The results of the RST and VSP indicated that the CO_2 penetrated approximately 300 feet horizontally and as much as 100 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 (STB) a day to 3 to 7 STB a day. The percentage of oil in the produced fluid, commonly referred to as the “oil cut,” also more than doubled, going from 2.8% to 6%. 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.

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INTRODUCTION

In recent years, the management of carbon dioxide (CO_2) emissions from large industrial point sources has been identified as a potential means to mitigate global climate change. Efforts to reduce CO_2 emissions now are a significant focus for energy producers and users, including the general public, governments, industry, regulators, and nongovernmental organizations. Carbon capture and storage (CCS) in geological media have been identified as important mechanisms for reducing anthropogenic CO_2 emissions currently vented to the atmosphere. Several geologic settings for geological storage of CO_2 are available, such as in depleted oil and gas reservoirs, deep saline formations, CO_2 flood enhanced oil recovery (EOR) operations, and enhanced coalbed methane recovery.

The PCOR Partnership recently evaluated the potential for geological sequestration of CO_2 in a deep carbonate reservoir for the dual purpose of CO_2 sequestration and EOR. Previous studies indicated that Williston Basin oil fields may have the capacity to store over 500 million tons of CO_2 as part of CO_2 flood EOR operation (Sorensen et al., 2006). As part of the PCOR Partnership Phase II field demonstration program, activities to improve understanding and develop technologies and approaches for CO_2 monitoring, verification, and accounting (MVA) and EOR have been, and continue to be, conducted. The goals of such activities are to 1) evaluate the technical and economic viability of CO_2 injection in carbonate oil reservoirs at depths greater than 8000 ft, 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 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. This RTIP has been developed to 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 CCS operators with previously unavailable information regarding the deployment of RST and VSP technologies as part of an MVA plan.

To achieve the goals of the Phase II Williston Basin EOR Field Demonstration, the PCOR Partnership conducted field and laboratory activities to determine the effects of injecting CO_2 using a HnP approach into a carbonate formation in the Northwest McGregor oil field in Williams County in northwestern North Dakota. Key commercial partners in the project included Eagle Operating Company, Schlumberger Carbon Services, and Praxair. The technical team, led by the Energy & Environmental Research Center (EERC), 1) determined the baseline geological characteristics of the injection site and surrounding areas, 2) injected CO_2 into the target oil reservoir using a HnP approach, 3) applied the RST and VSP technologies before and after injection in an attempt to visualize the vertical and horizontal extent of the injected CO_2 plume, and 4) evaluated the effect that injected CO_2 had on the ability of the oil reservoir to store CO_2 and produce incremental oil. Eagle Operating provided access to the site (which is owned and operated by Eagle Operating) and conducted all operational and maintenance activities related to the well. CO_2 was purchased from Praxair, which also designed and conducted the injection process in close collaboration with the EERC. The EERC and Schlumberger conducted characterization activities to develop data on baseline conditions and determine the effects of CO_2 on the reservoir during and after the injection phase. The CO_2 MVA activities at the site were jointly designed and implemented by the EERC and Schlumberger Carbon Services. Specific key elements of the MVA plan included 1) site characterization to establish baseline geological, geochemical, and geomechanical conditions; 2) measurement of surface flows and periodic analysis of fluid samples to evaluate the fate of injected CO_2 through mass balance; 3) monitoring the movement of injected CO_2 in the reservoir through the use of the RST, which provides data on near-wellbore gas/fluid saturation and VSP, which generates data on the lithology and gas/fluid saturation away from the wellbore up to 1000 feet away from the point of injection; 4) determination of the effects of CO_2 injection on key formation properties through close monitoring of pressure and production rate data; and 5) monitoring for out-of-zone migration through the use of a deep observation well and a shallow groundwater well.

Regional characterization activities indicated that Williston Basin oil fields may have over 1.2 billion barrels of incremental oil that could be produced from CO_2 EOR operations (Smith et al., 2006). Oil is produced from at least a dozen rock formations at depths ranging from less than 3000 ft on the northeast margin of the Williston Basin to greater than 14,000 ft near the basin center. While the CO_2-based EOR operations at the Weyburn and Midale Fields in Saskatchewan are good examples of economically and technically successful injection of CO_2 for simultaneous EOR and sequestration, the depths of injection and, therefore, reservoir conditions in those fields are relatively shallow (ca. 4600 ft) 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 8000 ft. To achieve that goal, a CO_2 HnP test was conducted in a well producing oil from an interval of the Mississippian-age Madison Group at a depth of approximately 8050 ft in the Northwest McGregor oil field in Williams County, North Dakota.

Approximately 440 tons of CO_2 was injected into a single well, the well was shut in to allow the CO_2 to "soak" for 2 weeks, and the well was brought back into production. The literature indicates that HnP operations can be an economically and technically efficient means of evaluating the response of a reservoir to CO_2, both with respect to EOR and CO_2 storage. Unique elements of the Madison Group 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:

- At a depth of 8052 ft, it would be among the deepest.
- Pressure (3000 psig) and temperature (180°F) would be among the highest.
- Most HnPs in the literature have been conducted in clastic reservoirs, whereas the Northwest McGregor field is a carbonate (limestone) reservoir.

The dynamic response of the injection zone was evaluated for changes over the course of the project using a variety of downhole logging tools and pressure monitoring in both the injection well and another nearby producing oil well. Using a petrophysical model of the Northwest McGregor oil field, preinjection predictions regarding the distribution of injected CO_2 in the target reservoir were compared to actual postinjection reservoir conditions as monitored over the duration of the study period. The results of this project provide previously unavailable insight regarding the fate of injected CO_2 within a relatively deep carbonate target reservoir, particularly with respect to the penetration of CO_2 away from the borehole and into the reservoir and the effect of the CO_2 on the productivity of the oil well after injection. Overall, the results of the field demonstration provide stakeholders with key information regarding 1) the viability of CO_2-based HnP operations as an option for improved oil recovery in deep carbonate oil reservoirs and 2) the consideration of deep carbonate oil reservoirs as reasonable targets for large-scale CO_2 storage.

Philosophical Approach

There is a broad range of technologies and approaches that can be, and in some cases have been, applied to CO_2 storage projects of various scales around the world. Early geological storage research and demonstration projects deployed MVA strategies that were developed based on a lack of knowledge about the effectiveness and utility of many of the applied technologies. The absence of knowledge required early projects to gather as much data as possible using a wide variety of techniques. In particular, a desire to "see" the plume of injected CO_2 led to a strong emphasis on the use of geophysical data, especially 3-D and 4-D seismic, to monitor the plume. While the use of geophysical-based approaches and techniques in early projects yielded valuable results that are essential to the development of geological storage as a CO_2 mitigation strategy, their high costs of deployment and often limited ability to identify CO_2 in many geologic settings may render them as being the exception rather than the rule when it comes to developing MVA plans for future projects. If the implementation of CCS is to occur on a large enough scale to help mitigate greenhouse gas emissions, then economics must be a primary consideration at the earliest stages of project development. At the same time, a detailed understanding and effective demonstration of the technical feasibility with respect to injectivity, capacity, containment, and overall safety are essential for all stakeholders to accept the concept of large-scale CO_2 injection. This is the context within which a philosophical approach was developed and applied in the PCOR Partnership Phase II Program.

In many cases, EOR projects and depleted oil and gas pools provide the most favorable locations for long-term CO_2 storage from both a technical and economic standpoint. From the technical perspective, such sites benefit from a relative wealth of previously generated, readily available subsurface characterization and reservoir production and injection data. These data provide critical, invaluable insight regarding the long-term prospects for technically feasible and safe injection and storage of acid gas. From an economic perspective, hydrocarbon reservoirs (and especially those that are suitable for EOR projects) are attractive because the use of existing infrastructure can lower the start-up costs of a project while the production of incremental oil can be used to offset the costs of capital, operations, and maintenance and, ultimately, bring profitability to the project. The use of established hydrocarbon reservoirs also benefits from the fact that a regulatory framework already exists for permitting many, if not all, of the necessary surface and subsurface operations.

The philosophical approach of the PCOR Partnership toward the design, implementation, and operation of the MVA plan and associated project activities was to:

- Maximize the use of previously generated data on the geological, geochemical, and geomechanical characteristics of the formation into which CO_2 was to be injected (target injection zone) and the overlying low-permeability rock formations that would serve as seals.

- Judiciously obtain key data beyond that which are already collected by the operator as part of the "normal" or "standard" operation of an EOR or acid gas disposal project.

- Apply and design new or nonstandard testing or technologies in the field in close consultation with the field managers and operators to minimize disruption of normal oil field operations.

The application of these fundamental guiding principles to the planning and operation of the Northwest McGregor project ensured that the goal of demonstrating the economic feasibility of CO_2 injection for simultaneous EOR and CO_2 storage could be achieved. That being said, the PCOR Partnership and Eagle Operating did recognize the value of developing previously unavailable fundamental data sets that could provide new understanding of mature oil field development and CCS, as well as guide the direction of future CCS research. With that in mind, the PCOR Partnership did seek and, when appropriate, acted on opportunities to cost-effectively conduct additional activities that were of a more research-oriented nature and which would not typically be part of future, nonresearch EOR and/or CCS projects.

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 at 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 offered the PCOR Partnership 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.

Technical Approach

While many large-scale CO_2-based EOR projects have been conducted in North America since the 1970s, few of these projects have included MVA programs that supported the goals of long-term CCS. While ongoing CCS projects at Weyburn and Midale, Saskatchewan, have provided and continue to provide valuable data regarding large-scale CCS, there is still a need to test and refine a variety of MVA technologies in the context of cost-effectiveness, particularly at depths that are more typical of reservoirs in the Williston Basin (>8000 ft). For the Northwest McGregor demonstration project, the goals of the PCOR Partnership were to 1) evaluate two specialized geophysical reservoir characterization techniques, 2) examine the efficacy of using CO_2 for EOR in deep (>8000 ft) carbonate reservoirs, and 3) develop a better understanding of the effects of CO_2 storage on a deep carbonate reservoir/seal system. To accomplish these goals, the PCOR Partnership chose to conduct a HnP operation using the E. Goetz No. 1 well in the Northwest McGregor oil field in Williams County, North Dakota.

A CO_2-based HnP operation is a well stimulation or EOR technique that is typically conducted on a single well that is not part of a secondary or tertiary oil recovery operation. CO_2-based HnP operations have been conducted globally at hundreds of individual well locations, and there is a wealth of published information on the effectiveness of this technique for the stimulation of mature wells in a variety of reservoir settings (Mohammed-Singh et al., 2006). The engineering and operational aspects of HnP operations are typically very site-specific, and the usefulness of a detailed description and discussion of those aspects of the Northwest McGregor operation would have limited applicability and is beyond the scope of this RTIP. That being said, a generalized description of the key elements of a HnP operation is valuable with respect to understanding the context of the project. Over the course of a typical HnP operation, the producing oil well will be put through three phases (Hyne, 1991). During the huff (injection) phase, CO_2 is injected into the reservoir through the well for a period of days to weeks. Following the injection is the soak, or shut-in, phase, during which the well is shut-in for several days to weeks to allow the CO_2 to dissipate in the reservoir and dissolve into the oil, thereby causing it to swell and become less viscous. During the puff (production) phase of the operation, the CO_2-affected oil is produced from the well (Hyne, 1991). Because the HnP operation conducted by the PCOR Partnership included a variety of non-industry-standard characterization and testing activities as part of the project, the field-based work conducted at the E. Goetz No. 1 oil well was classified into six distinct phases, as presented below:

- Preinjection Phase – The preinjection phase included the gathering of readily available historical reservoir and production data, primarily from the North Dakota Department of Mineral Resources' (NDDMR) well files, that supported the development of an effective injection and monitoring plan. The preinjection phase also included field-based well preparation activities (i.e., swabbing, inspection of tubing and rods, and casing tests, etc.) that were necessary for preparing the well for CO_2 injection. Field-based site characterization activities were also conducted in the preinjection phase, including the application of ultrasonic logging to determine the preinjection condition of the well casing and cement, the deployment of the RST and VSP technologies to obtain baseline fluid saturation conditions in the reservoir, and the collection of downhole and near-surface fluid samples to determine baseline geochemical conditions. The overall preinjection phase lasted several weeks, although the field-based components were conducted over a period of approximately 2 weeks.

- Injection Phase – The injection phase primarily included the mobilization and setup of the CO_2 pumping unit at the E. Goetz No. 1 well location and the injection of CO_2 into the well. The injection phase also included the simultaneous injection of a perfluorocarbon tracer into the well to serve as an additional means of monitoring the movement and fate of the CO_2. The injection phase occurred over the course of approximately 1 week.

- Postinjection Phase – The postinjection phase was the period of time immediately after the injection of CO_2. During this phase, initial postinjection pressure and temperature data were obtained, downhole temperature and pressure sensors/recorders (commonly referred to in the oil field industry as "bombs") were installed in the well to record those parameters during subsequent soak and production phases, and one downhole geophysical logging event (using the RST) was conducted. The size and nature of the RST allowed for its deployment into the well in such a manner that there was no loss of pressure in the well and, therefore, no effect on the CO_2 in the reservoir. It was not possible to run the downhole portion of the VSP technology into the well without fully opening the well and losing reservoir pressure; therefore, the VSP was not deployed during this phase of the operation. The postinjection phase was conducted within the first week following the end of the injection.

- Soak Phase – The soak phase was the time during which the E. Goetz No. 1 well was undisturbed and CO_2 was allowed to soak into the reservoir. Monitoring of pressure at the surface was the only well-related activity conducted during this time. The duration of the soak period is determined by the nature of fluids that are produced within 24 hours of first reopening the well. If only CO_2 is produced, then the well is shut in again and allowed to soak for a longer period of time. If oil is produced, then the soak period is considered to be over and the production phase is begun. While the literature suggests that the soak period for HnP operations can last anywhere from 2 weeks to several weeks, the soak period for the E. Goetz No. 1 HnP was approximately 2 weeks.

- Production Phase – The production phase is the period of time during which the well produces oil at a rate that is greater than the preinjection rate. The literature indicates that this can last anywhere from weeks to several months, depending on a variety of reservoir-specific factors. During the production phase, oil, gas, and water production data were obtained, and surface samples of fluids from the E. Goetz No. 1 and the E.L. Gudsvangen No. 1 wells were collected and analyzed periodically. Fluid samples were also collected from shallow groundwater wells in the vicinity of the E. Goetz No. 1 well and analyzed for CO_2, tracer, and other standard parameters, including ions and metals. For the purposes of the PCOR Partnership Phase II Program, the production phase was considered to have lasted approximately 3 months. Actual improved oil productivity was still occurring after this time, but the Phase II schedule dictated that postproduction activities be conducted before the E. Goetz No. 1 well had gotten back to its preinjection productivity.

- Postproduction Phase – In addition to the routine surface pressure monitoring and fluid sampling from the E. Goetz No. 1 and E.L. Gudsvangen No. 1 wells, the postproduction phase of the PCOR Partnership Phase II Northwest McGregor HnP project included a final round of downhole fluid sample collection and analysis; application of the ultrasonic, caliper, and RST logging technologies; and acquisition of VSP data. The postproduction phase was conducted over the course of approximately 2 weeks.

As part of the site selection process for this project, a screening was performed to determine if the E. Goetz No. 1 well was a good candidate for incremental oil production from a CO_2 HnP operation. The screening included using readily available reservoir characteristics and historical production data from the NDDMR well files to estimate potential incremental oil production from the model developed by Patton et al., (1982). The E. Goetz No. 1 well prediction was also compared to four other HnP examples (Table 1) that were analogous with respect to either depth, fluid properties, or reservoir lithology (in this case limestone). Although examples in literature were not entirely analogous, some examples did provide insight and allowed for some level of comparison to the E. Goetz No. 1 well and its reservoir. Very few examples of CO_2 HnP operations were found for deep carbonate reservoirs, and earlier predictive models are based only on shallow heavy and light oils.

The model provided by (Patton et al., 1982) was used to estimate the potential incremental oil production from the E. Goetz well, evaluate which variables are likely to contribute significantly to incremental production, and determine how much CO_2 to inject. The predicted incremental production was 2100 stock tank barrels (STB). This estimation is compared to other documented operations in Table 1, which indicates that the model provided by Patton et al. (1982) is a reasonable prediction. The sensitivity analysis of injection variables indicated that injection pressure, volume of injection, and pay thickness have the greatest impact on predicted results. The optimum economically recoverable injection volume was estimated at 400 tons.

For purposes of discussion in the context of this report, the technical aspects of the PCOR Partnership Phase II project at Northwest McGregor generally can be thought of as falling into two categories: 1) the MVA program and 2) the injection/production program. These categories are not necessarily independent of each other, with some activities and data sets being common between the two categories. However, for the sake of effective discussion in the context of the RTIP, they are presented in this report in relatively independent sections, with categorization being based largely on what was deemed to be the primary purpose of each activity.

Table 1. Reservoir Properties and Incremental Oil Production from Literature for Comparable Wells

Source	Reservoir Depth, ft	Pay Thickness, ft	Reservoir Temperature, °F	Reservoir Pressure, psig	Permeability, mD	Porosity, %
E. Goetz	8052	10	200	3000	0.35	15
Texas Study Similar Depth	7756	15	175	1200	15	20
Texas Next Closest Example	4200	40	135	660	388	25
Louisiana Example	8140	21	185	3847	322	29
Limestone Example	4125	200	116	1736	350	12

Source	Oil Saturation, %	Oil Gravity (API[1])	Viscosity, cP	CO_2 Injected, tons	Incremental Oil, STB	Patton et al. Calc., STB
E. Goetz	50	41.7	2	400		2108
Texas Study Similar Depth	–	37	1.6		None	1159
Texas Next Closest Example	73	23	33.4	470	1657	2036
Louisiana Example	90	35	1.3	510	3233	4379
Limestone Example	90	10	415	1250	4704	7847

[1] American Petroleum Institute.

The purpose of the MVA program was to 1) provide a set of baseline conditions upon which the effects of the injection can be compared to data gathered during and after injection operations, 2) generate data that evaluate the security of the injection program from the perspectives of containment and safety, and 3) establish a technical framework for the determination of the effectiveness of Schlumberger's RST and VSP technologies as a means of identifying and monitoring the plume of injected CO_2 in a deep carbonate reservoir setting. MVA program activities that resulted in the determination of baseline conditions include geological and hydrogeological 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 (Appendix A), determination of material balance based on the collected field data, and a modeling-based study of the effectiveness of CO_2-based HnP with respect to CO_2 fate and enhanced oil productivity. Generally speaking, monitoring activities are 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, a shallow groundwater well in the vicinity of the Northwest McGregor HnP test was tested before injection, during the operational phase of the project, and at the end of the project performance period to ensure that the CO_2 injection program did not impact local groundwater resources.

The purpose of the injection/production program is to 1) ensure the safe and effective injection of CO_2 into the Northwest McGregor Mission Canyon Reservoir and 2) evaluate the potential production of incremental oil from Mission Canyon Reservoirs. Key aspects of the injection program include the procurement and transportation of CO_2 to the site location, well preparation and maintenance activities, and CO_2 injection and standard oil production operations.

The PCOR Partnership Phase II Northwest McGregor HnP project was conducted by a multidisciplinary team of engineers, scientists, regulators, and management personnel. The management team for the project included representatives from Eagle Operating and the EERC. The primary technical team comprised technical professionals from Eagle Operating, the EERC, Schlumberger Carbon Services and Schlumberger Oilfield Services, Praxair, and the NDDMR Oil and Gas Division. Effective, frequent communication between all team members was critical to the timely, cost-effective design and implementation of all project activities. To facilitate communication and the appropriate sharing of project data, conference calls were held on at least a quarterly, often monthly, and sometimes weekly basis. Integration of activities in a cross-disciplinary manner facilitated efficient implementation of project plans. Such integration, while effective from a project management and budget standpoint, sometimes blurred the lines between the various elements of the program, which further underscored the need for frequent, diligent reporting of activities and results and thoughtful interpretive discussion between team members.

BACKGROUND

Northwest McGregor Location and General Geological Setting

The Northwest McGregor oil field is located in Williams County in northwestern North Dakota, approximately 20 miles north of the town of Tioga. The field covers an area of about 30 mi^2 in an area of glaciated prairie uplands. The prairie upland area is dominated by cultivated small grain fields and ranchland, with sporadic areas of prairie pothole wetlands. The area is subject to typical northern latitude interior plains weather patterns, including severe cold winter temperatures, wet springs, and warm, dry summers. Figure 1 shows the location of the Northwest McGregor oil field within the PCOR Partnership region. Figure 2 shows the relative locations of the E. Goetz No. 1 well, which served as the injection well, and the E.L. Gudvangen No. 1 well, which served as a deep observation well, within the Northwest McGregor oil field. Figures 3 and 4 are photographs of the E. Goetz No. 1 and E. L. Gudvangen No. 1 well locations, respectively. Both oil wells are owned and operated by Eagle Operating Company, an independent oil company with headquarters in Kenmare, North Dakota.

From a geological perspective, the Northwest McGregor oil field is located on the northern end of the Nesson Anticline, a large structural feature near the depositional center of the Williston Basin that includes some of the largest accumulations of oil in the PCOR Partnership region (Figure 5). The primary oil productive zone in the Northwest McGregor oil field is the

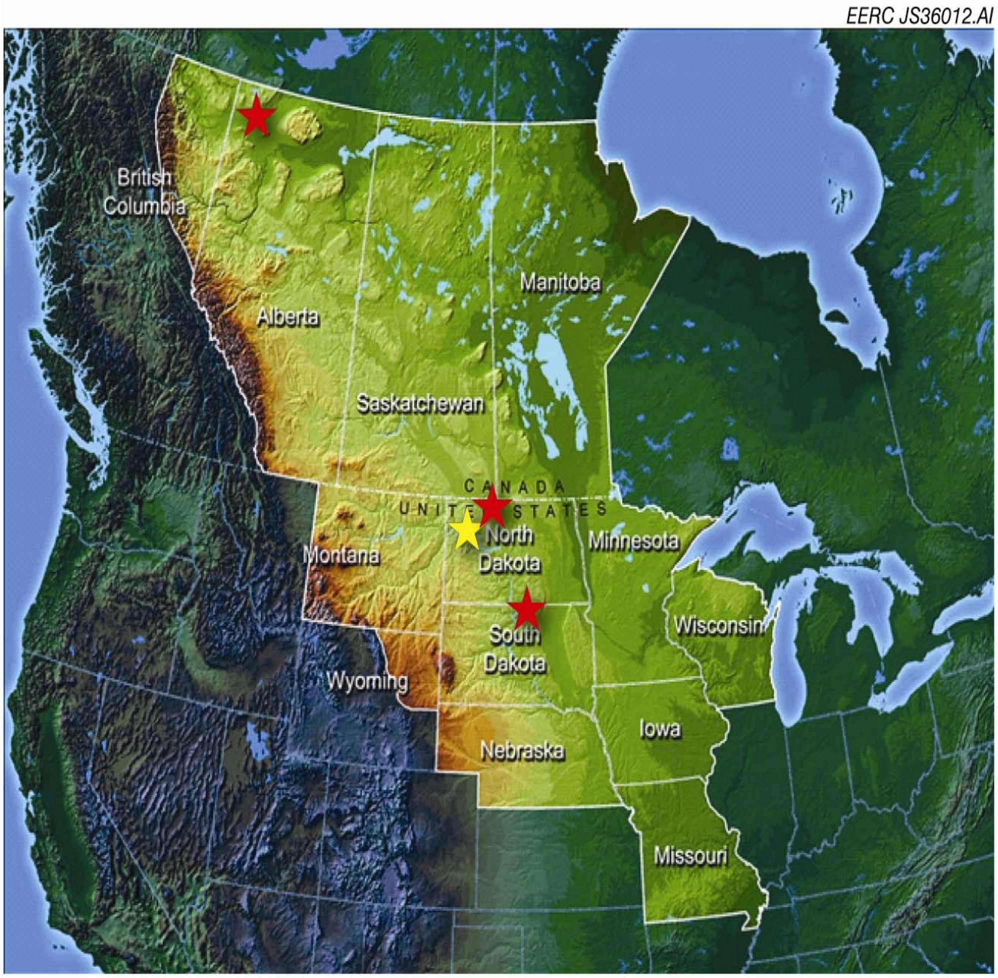

Figure 1. Location of Northwest McGregor site (yellow star) within the PCOR Partnership region. The locations of other PCOR Partnership Phase II field demonstrations are shown in red.

Mississippian-age Mission Canyon Formation, which is the middle member of the Mississippian Madison Group (Figure 6). The Mission Canyon Formation is, in turn, further divided into several distinctive lithofacies representing deposition of predominantly carbonate sediments and evaporites in environments that ranged from open marine to coastal sabkha or salina, thereby recording a major regressive sequence (Lindsay, 1988; Kent et al., 1988). Within that regressive event, repetitive carbonate shoaling upward cycles are recognized. The productive Mission Canyon zones in the Northwest McGregor field, including the one from which the E. Goetz No. 1 well produces, have been interpreted to be such shoals. Specifically, the zone from which oil production occurs and into which CO_2 injection was targeted is considered to be part of the informally named Frobisher Lithofacies. This zone is capped by a thick zone of tight carbonates and anhydrites, including an anhydrite layer approximately 50 feet thick. The entire Mission Canyon sequence is, in turn, capped by the Charles Formation, which in Williams County comprises several hundred feet of impermeable salt (Fischer et al., 2004). This series of tight

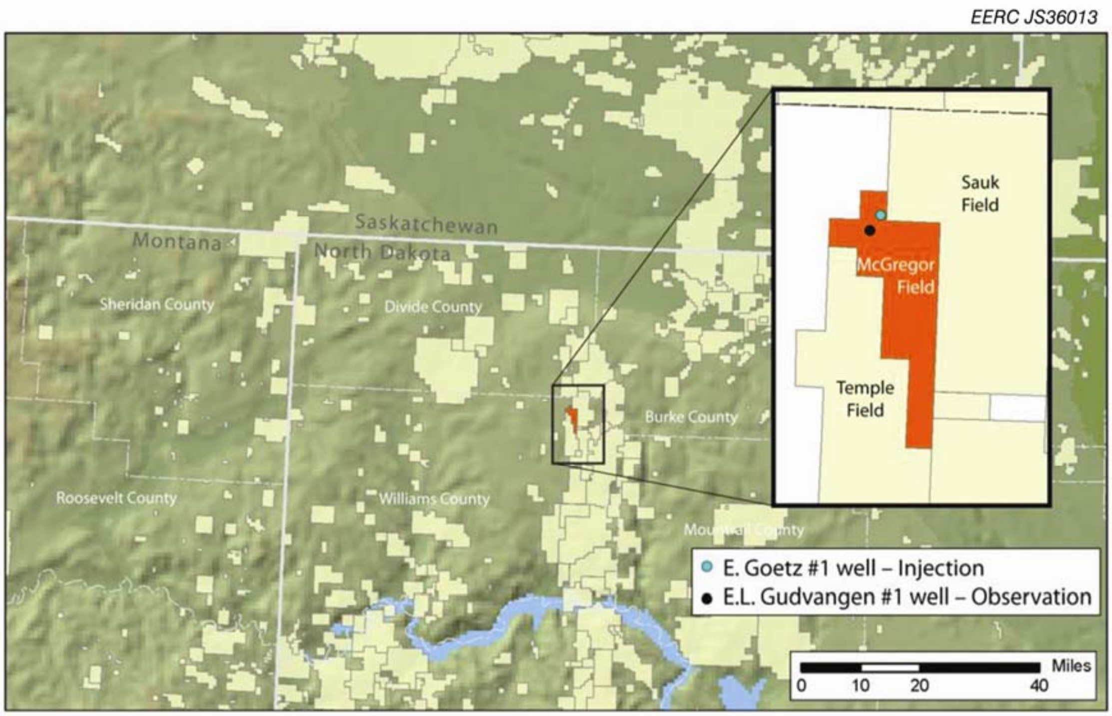

Figure 2. Map view of Northwest McGregor oil field with relative locations of the injection and observation wells.

Figure 3. Photo of the E. Goetz No. 1 well site location which served as the injection and production well for the Northwest McGregor HnP test.

Figure 4. Photo of E.L. Gudvangen No. 1 well, which served as an observation well for the Northwest McGregor HnP test.

carbonates, anhydrites, and salts serve as a stacked series of excellent seals to prevent upward migration of CO_2 from the target injection zone into any underground sources of drinking water (USDW). In addition, the anticlinal nature of the Northwest McGregor Field limits lateral migration of the injected CO_2.

Overview of the Northwest McGregor Field, E. Goetz No. 1 Well Operational History

The Northwest McGregor oil field began producing oil in the early 1960s. Over the course of its operational lifetime, as of 2009, the Northwest McGregor oil field has produced over 2.2 million barrels of oil from 14 wells. The E. Goetz No. 1 well was initially drilled in 1963, with production from the Mission Canyon beginning in 1964 and continuing through and beyond the time period of this project. Table 2 provides data on the initial reservoir conditions of the Northwest McGregor Mission Canyon Reservoir at the E. Goetz No. 1 location.

BASELINE CHARACTERIZATION

The purpose of the baseline characterization activities was to establish the integrity of the Northwest McGregor Mission Canyon Reservoir with respect to CO_2 injection and determine the key characteristics of the reservoir with respect to oil, gas, and water production. The preinjection baseline data served as a foundation by which data generated over the course of the later project phases could be compared. This was accomplished by carrying out the following activities:

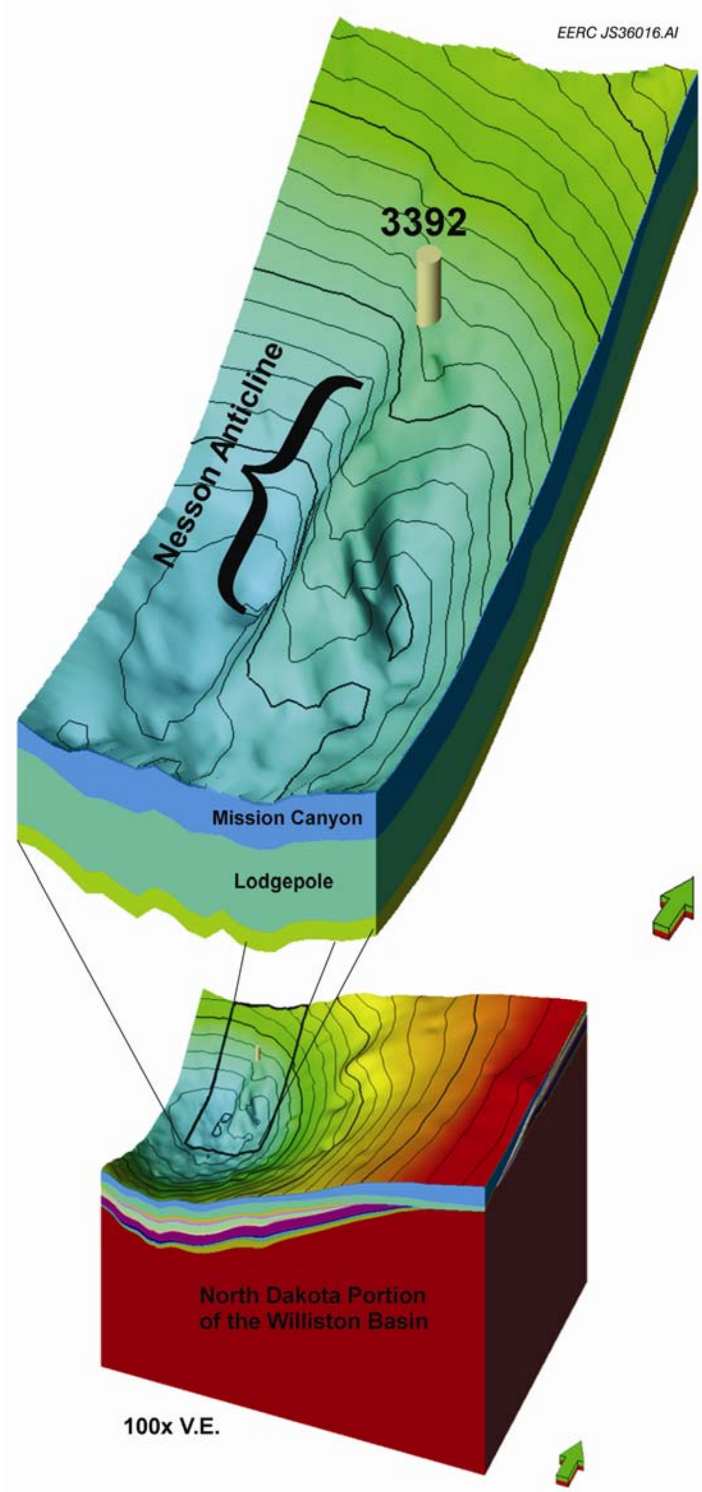

Figure 5. Large-scale structural setting of the surface of the Frobisher–Alida interval of the Mississippian Mission Canyon Formation in the North Dakota portion of the Williston Basin. The Nesson Anticline is a large north–south-running anticline near the depositional center of the basin.

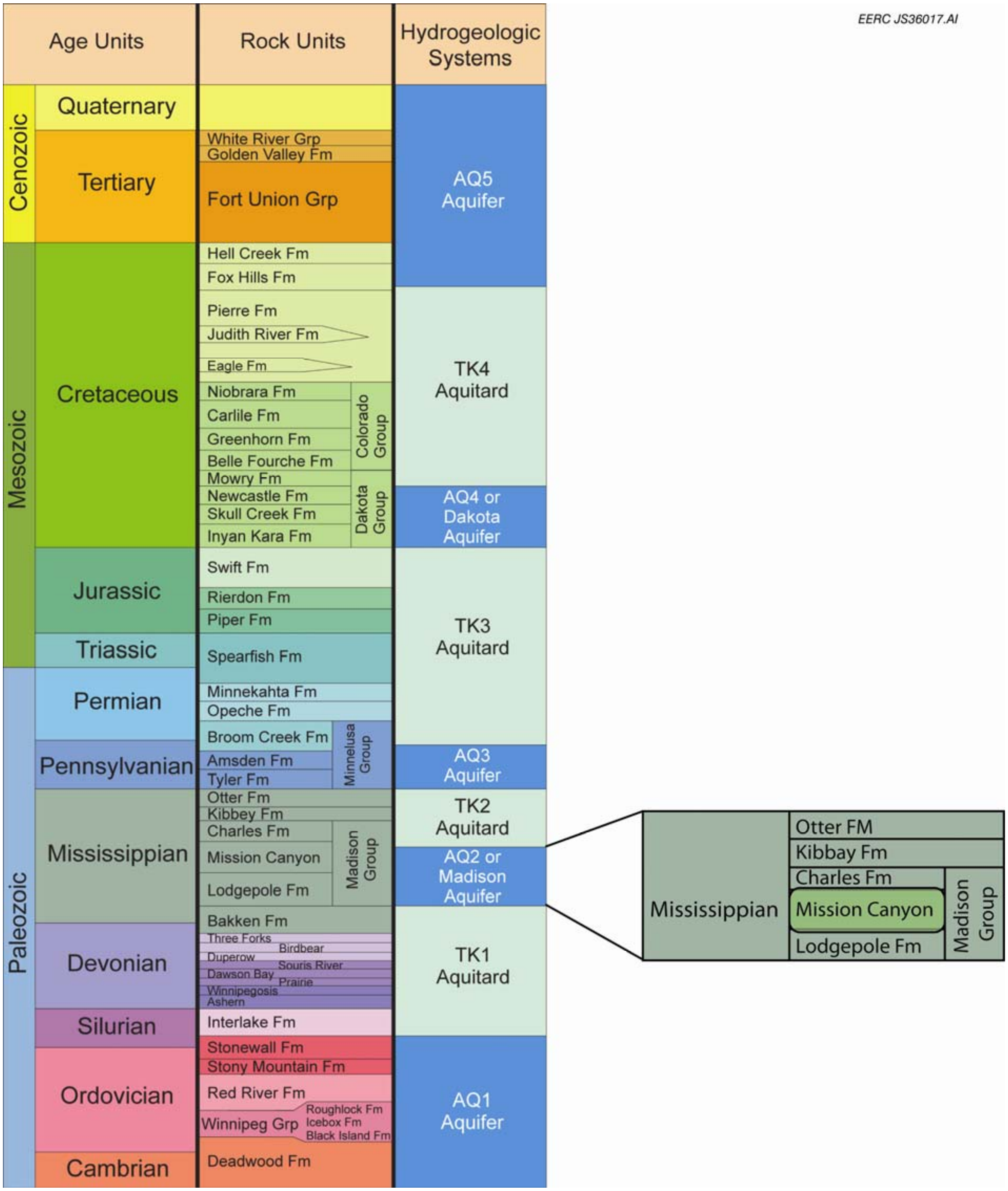

Figure 6. North Dakota Williston Basin stratigraphic column, with the Mission Canyon Formation highlighted. The three aquitard systems overlying the Madison Aquifer system will act as major seals for any CO_2 injected into the Mission Canyon Formation.

Table 2. Initial Conditions of the Mission Canyon Reservoir of the Northwest McGregor Oil Field and the E. Goetz No. 1 Well

Reservoir Characteristics	
Producing Formation	Mission Canyon
Lithology	Primarily limestone
Average Pay Thickness	14 ft
Average Porosity	15%
Matrix Permeability	0.35 md
Secondary Permeability	Fractures
Depth from Surface to Pay	8050 ft
Average Temperature	216°F
Original Discovery Reservoir Pressure	3127 psig
Preinjection Reservoir Pressure	2700 psig
Oil Gravity (API)	41.7°
Cumulative Oil Production	2.2 million STB
E. Goetz No. 1 Well Characteristics	
Location	Sec. 12, T159N, R96W
NDIC[1] Well Number	3392
Initial Production Date (Mission Canyon)	10/1/1964
Surface Elevation	2304 ft (above mean sea level)
Perforated Interval	8052 ft to 8062 ft (from surface)
Casing Inside Diameter	5½ in.
Tubing Inside Diameter	2⅜ in.
Packer Set Depth	7788 ft. (from surface)
Average Preinjection Oil Production Rate	40 STB/month
Cumulative Oil Production	53,000 STB
Cumulative Water Production	356,000 STB
Cumulative Gas Production	574 MCF

[1] North Dakota Industrial Commission.

- Data reconnaissance and integration
- Baseline geology and hydrogeology characterization
- Rock mineralogy and formation water composition determination
- Geomechanical property evaluation
- Assessment of wellbore integrity and leakage potential

Data Reconnaissance and Integration

Efficient data acquisition, evaluation, and integration through the use of data management tools are crucial early steps in the establishment of baseline conditions. Data reconnaissance and integration activities for the Northwest McGregor project included the following:

- Well/reservoir information for the pertinent formations.

- Data on drilling, completion, and stimulation/workover activities.

- Digital production history of the key wells.

- Geological and geophysical information on the key formations, including formation isopach and depth maps, well logs, interpreted seismic data, hydrogeological characteristics, drill stem test data, core-testing data, etc.

- Reservoir engineering data from other HnP operations that may be analogous.

Baseline Geological and Hydrogeological Characterization

Identifying and characterizing the geological setting and hydrogeological regime at a CO_2 injection site are important to understand possible migration pathways and the effect the flow of formation water may have on the movement and fate of the injected CO_2. The Mission Canyon Formation is part of the AQ2 Aquifer, also known as the Madison Aquifer System. As shown in Figure 6, three aquifer systems and three aquitard systems are present in the sedimentary succession overlying the Mission Canyon Formation. The following information was collected as part of the Northwest McGregor characterization activities and should be a part of any characterization program for a CCS project:

- Hydrostratigraphic delineation

- Aquifer and aquitard geometry and thickness

- Rock properties relevant to the flow of formation waters and injected gas, such as porosity and absolute and relative permeability

- Geothermal regime

- Pressure regime

- Direction and strength of formation water flow

As part of the PCOR Partnership Phase I regional characterization efforts, an evaluation of the hydrogeological and hydrogeochemical characteristics of the Madison Aquifer System was conducted (Fischer et al., 2004). This evaluation included examinations and descriptions of the flow-driving processes and mechanisms in the region and strata of interest and provided the Phase II project with valuable insight regarding the potential effect of natural flow on fluid flow paths of both injected CO_2 and mobilized oil in the relevant Mission Canyon intervals in the Northwest McGregor study area. A detailed description of the Madison Aquifer System is beyond the scope of this RTIP; however, consideration of the hydrogeological information in the context of the Northwest McGregor HnP indicated that barring major leakage through the wellbore, the planned CO_2 injection at E. Goetz No. 1 would have essentially no geochemical or hydrodynamic impact on any of the aquifer systems in the study area. Furthermore, the volume of CO_2 being injected over the course of the HnP (<440 tons) is small enough that even if there were a major failure of the wellbore, the impacts to any of the potentially affected aquifer systems would be minimal and of a short-lived nature.

While larger CCS projects will conduct characterization activities at scales ranging from the reservoir to the basin, the small injection volume of the Northwest McGregor HnP project meant that the geologic characterization work was primarily carried out at the reservoir scale, although some work in immediately adjacent oil fields could be considered local-scale characterization. The characterization work focused on the Mission Canyon Formation, with an emphasis on the informally named Frobisher interval which has been interpreted to be the zone within the Mission Canyon from which oil is produced in the Northwest McGregor Field and into which the CO_2 was planned to be injected. Characterization work and subsequent modeling exercises conducted at the reservoir scale provide insight into predicting the immediate and early near-term effects of the injection operations, which is precisely the focus of any HnP effort. Reservoir characterization work is very detailed and can, and will, be frequently updated over the course of any injection program. This is because the data generated over the course of the injection itself and during the production period, such as history matching of injection and production curves, will provide new insight regarding the characteristics of the reservoir.

At the reservoir and local scales, information regarding the geology of the reservoir and confining strata (e.g., structural setting, stratigraphy, general lithology, thickness, areal extent, etc.) were collected, processed, and interpreted. This led to the creation of a geological model of the reservoir and sealing strata (also referred to as a static petrophysical model) for the Northwest McGregor HnP operation. The geological model was generated using data from 30 wells to evaluate reservoir geometry and internal architecture. Figure 7 is a cross section showing basic stratigraphy and structure for the Northwest McGregor oil field, while Figure 8 shows screen shots of the geological model illustrating distribution of four key reservoir parameters (permeability, total porosity, rock density, and facies) within the Mission Canyon Formation in the study area. In the case of the Northwest McGregor oil field, the oil-producing zone (interpreted to be within the Frobisher interval) is initially capped by a fairly thick (ranging from 20 to 30 ft) bed of anhydrite, which serves as the primary confining unit for the oil productive zone. In the E. Goetz No. 1 well, this anhydrite-dominated confining unit sits approximately 115 ft above the perforated interval, as shown in Figure 9. Figure 9 is a lithology column for the zone of interest (running from just below the productive reservoir to about 60 feet above the initial/primary cap rock) that was created based on the interpretation of several different sets of data from the E. Goetz No. 1 well, including historical well logs, cuttings descriptions in the well file, and core samples. The presentation of historical well log data in Figure 10 also demonstrates that there is a thick (40 ft) salt bed, referred to as the Last Salt, approximately 225 ft above the perforated zone. Finally, the entire Mission Canyon Formation in northwestern North Dakota is overlain by approximately 300 ft of evaporites in the Charles Formation, which further provide an excellent barrier to migration of CO_2 into any of the overlying aquifer systems.

Lithology, Mineralogy, Geomechanical Properties, and Formation Fluid Composition

Data regarding key properties of the reservoir rocks and fluids are critical to 1) estimating the potential effectiveness of the use of CO_2 in a HnP operation and 2) predicting the short-, medium-, and long-term effects of CO_2 injection on the reservoir. Because the Mission Canyon Formation has been one of the most prolific producers of oil in the Nesson Anticline portion of the Williston Basin, it has been the subject of numerous technical papers and academic studies.

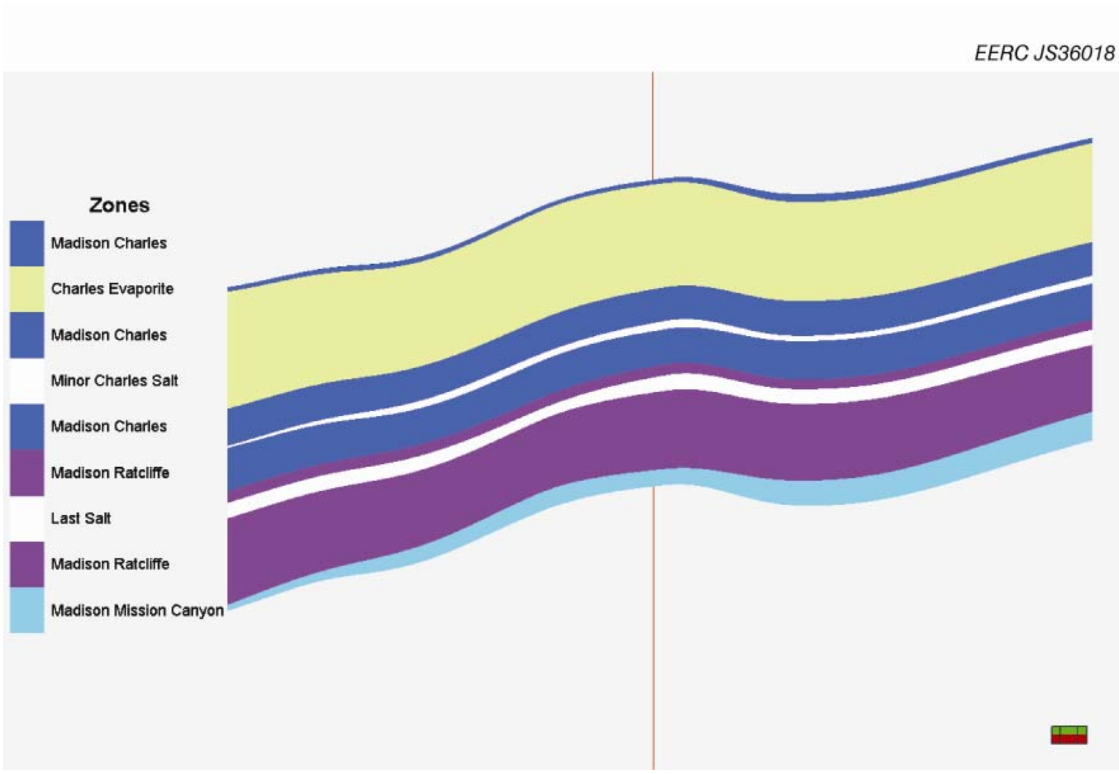

Figure 7. Generalized cross section showing the relative thickness and structure of the major rock units within the Mississippian Madison Group in the Northwest McGregor oil field. The red line indicates the relative location of the E. Goetz No. 1 well within the cross section.

With respect to the Northwest McGregor Field and its neighboring oil fields, there are bountiful data in well files that are publicly available through NDDMR. These papers, studies, and well files provide a tremendous amount of data regarding lithology, mineralogy, and formation fluid chemistry. These data are an excellent means of providing support to a variety of preinjection modeling activities, including the development of static geological models, site-specific geomechanical and geochemical modeling, and simulations of injection and plume transport and fate. Data sets that were used to understand the rock lithology and mineralogy of the reservoir and seals and the formation fluid composition of the reservoir included the following:

- Cuttings and core samples
  - Cuttings provide information on the lithology of the site, including the depth and thickness of such key intervals as potential injection zones, seals, and aquifers that need to be protected. At Northwest McGregor, cuttings were particularly valuable in positively identifying zones of anhydrite.
  - Core samples offer the opportunity to conduct a variety of tests that can be used to define the mineralogical, physical, and geomechanical properties of the rock. If available, cores of both reservoir and seal rocks should be tested, as seals that are demonstrated to be highly competent may provide a basis for allowing higher

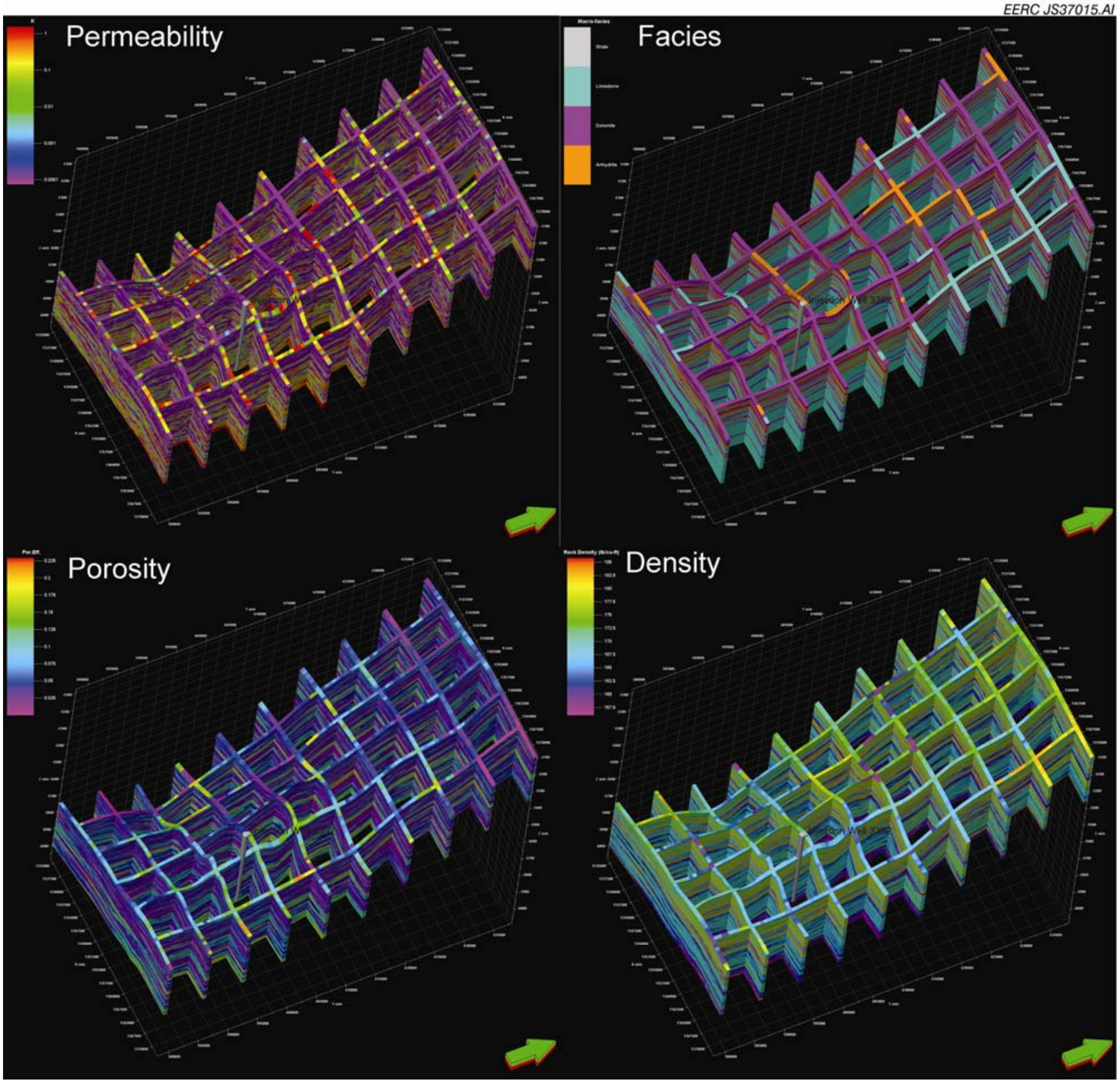

Figure 8. Screen shots of the Northwest McGregor study area geological model, showing distribution of permeability, total porosity, and facies within the Mission Canyon Formation.

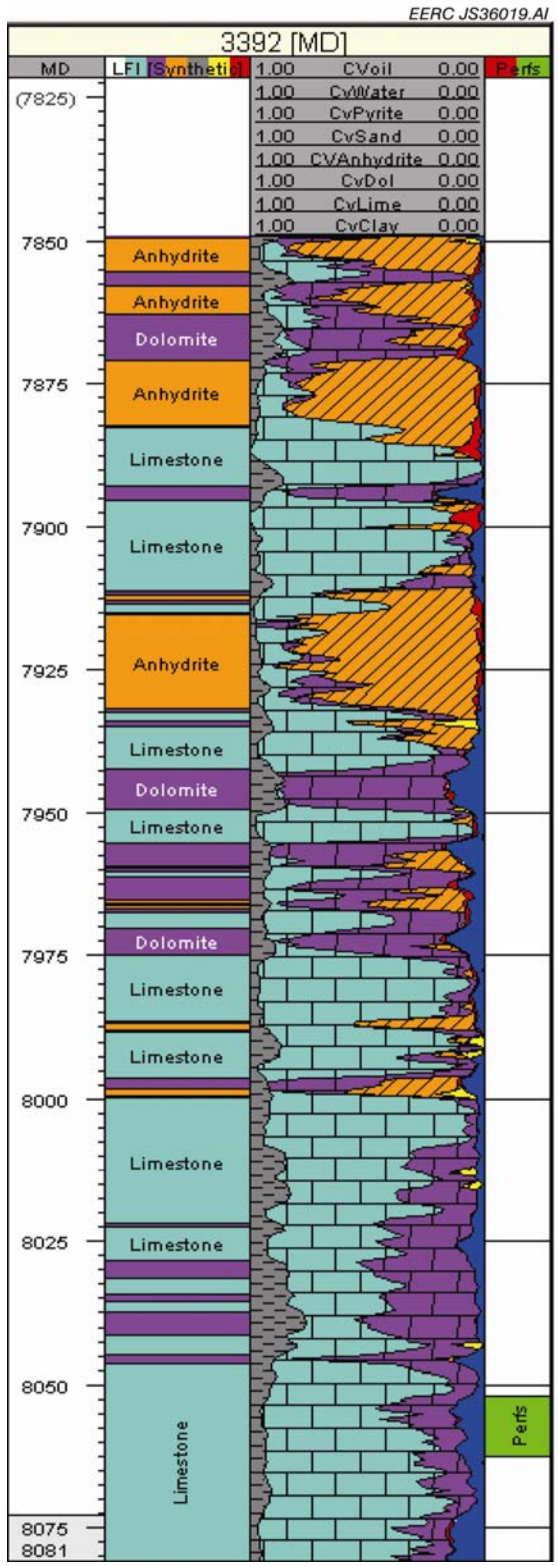

Figure 9. Lithology column for the zone of interest (productive reservoir and initial cap rock) in the E. Goetz No. 1 well, based on interpretations of well logs, cuttings descriptions, and core analysis.

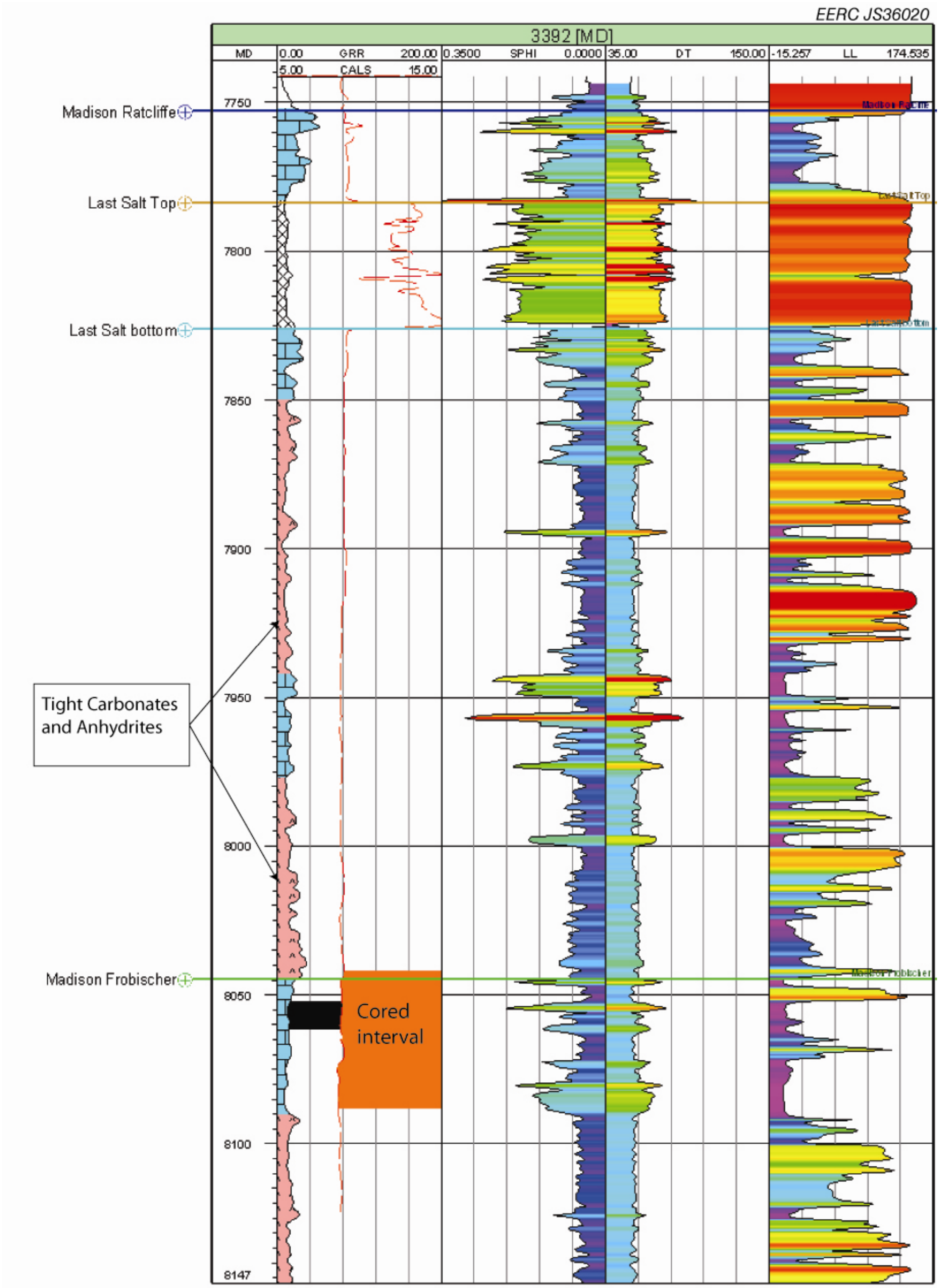

Figure 10. Historical geophysical logs illustrating the relative positions of the perforated interval (black), the cored interval (solid orange), and the informally named intervals of the Mission Canyon Formation that are relevant to the project, including the Frobisher Reservoir interval and the Last Salt, which serves as the primary major seal for the CO_2.

pressure injection than would otherwise be allowed. However, historically, oil companies have not typically collected core of sealing formations, so with respect to HnP operations, which will be conducted in older wells, it is atypical that such core will be available.

- For the Northwest McGregor Field, several wells, including the E. Goetz No. 1, were found to have been cored in the Frobisher interval of the Mission Canyon Formation. In particular, the North Dakota Geological Survey Core Library provided the EERC with access to the core from the E. Goetz No. 1 well and allowed the collection of plugs from that core for the purposes of more detailed testing, particularly with respect to mineralogy. Figure 11 is a photograph of one of the core samples collected from the E. Goetz No. 1 well. Perhaps the most useful aspect of the Northwest McGregor core was that it provided a means to qualitatively and semiquantitatively analyze the nature of fractures in the Mission Canyon Formation which, in turn, allowed for the development of fracture distribution models (Figures 12–14), referred to as discrete fracture network (DFN) simulations. The understanding of the fracture network in the Northwest McGregor oil field (or any highly fractured oil reservoir) is critical to predicting and interpreting the results of the HnP with respect to both CO_2 injection and improved oil production.

- The core samples from the Northwest McGregor Field, including those from the E. Goetz No. 1 well, were also used to conduct a variety of petrographic analyses, including scanning electron microscopy (SEM), x-ray diffraction (XRD), x-ray fluorescence (XRF), and other techniques. The results of these tests allowed for more detailed quantification of the mineralogy of the reservoir rocks and such key rock properties as total porosity and effective porosity. These data were incorporated into both the petrophysical modeling and geochemical modeling efforts which, in turn, supported the dynamic injection and production modeling activities.

- Formation fluid analyses

  - The collection of formation fluid (oil, gas, water) samples is critical to understanding the geochemical regime of the target injection zone. Geochemical analysis should include specific gravity, salinity, resistivity, total dissolved solids, anions, cations, organic acids, metals, and gas analyses (including hydrocarbons). At a minimum, the collection and analysis of such samples from surface facilities as close to the wellhead as possible should be done prior to injection. While not critical to designing or conducting a HnP operation, the collection of downhole reservoir fluid samples, their preservation at reservoir pressure, and subsequent analysis yield valuable data that provide a more accurate assessment of the geochemical regime of the reservoir. These analytical data support the development of geochemical models that can provide insight regarding the effects of the CO_2 injection on wellbore integrity and key reservoir properties such as permeability. As part of the Northwest McGregor HnP project, downhole fluid samples were collected and analyzed before CO_2 injection and after 3 months of production. Some of the key results are presented in Figure 15. These results allowed for the calibration of geochemical models that were

Figure 11. An example of a core sample from the E. Goetz No. 1 well. Note the vertical fractures, the analysis of which from this core and many others from the study area allowed for prediction of fracture distribution within the Mission Canyon Formation in the Northwest McGregor Field.

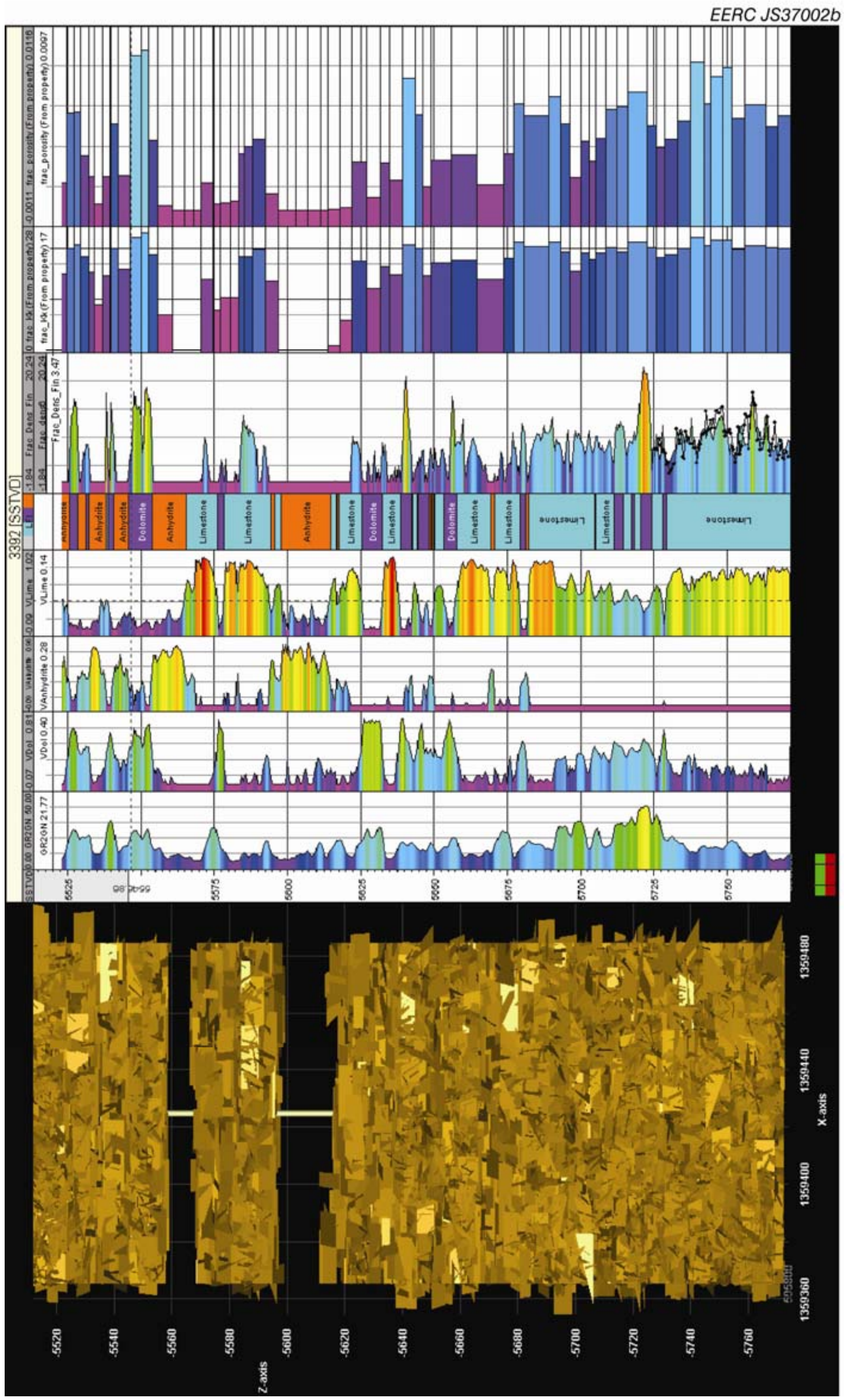

Figure 12. The interpretation of various geophysical logs, core sample evaluation and analysis, and sequential Gaussian simulation techniques were combined to develop predictions of fracture distribution within the reservoir and seals of the Mission Canyon in Northwest McGregor.

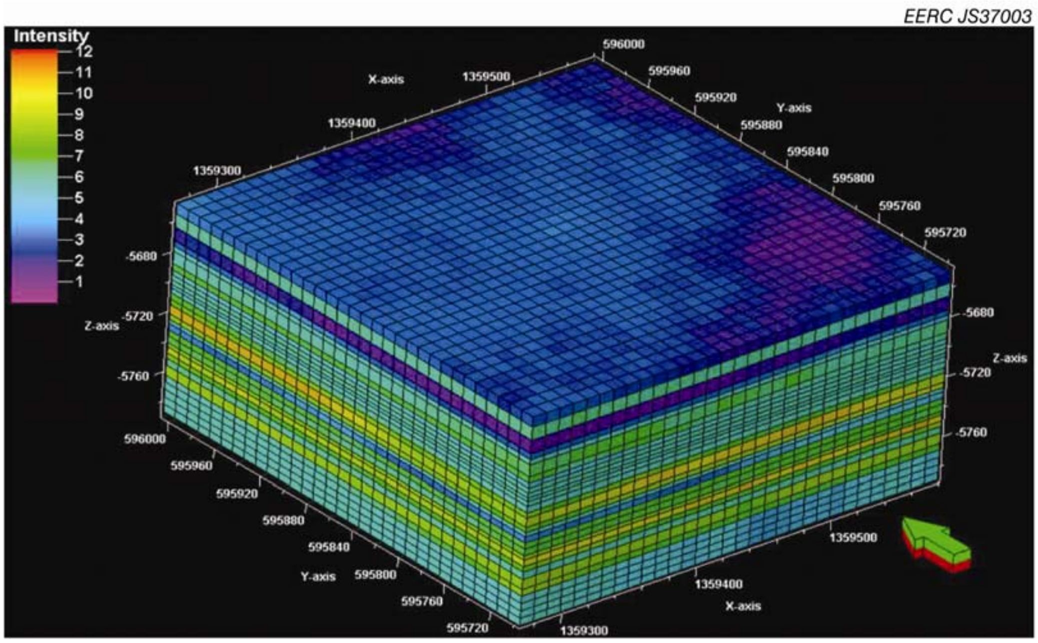

Figure 13. Fracture density grid created using sequential Gaussian simulation, which was used as input to develop a DFN simulation that ultimately became a critical component of the static geological model that was used to conduct dynamic HnP injection and production simulations.

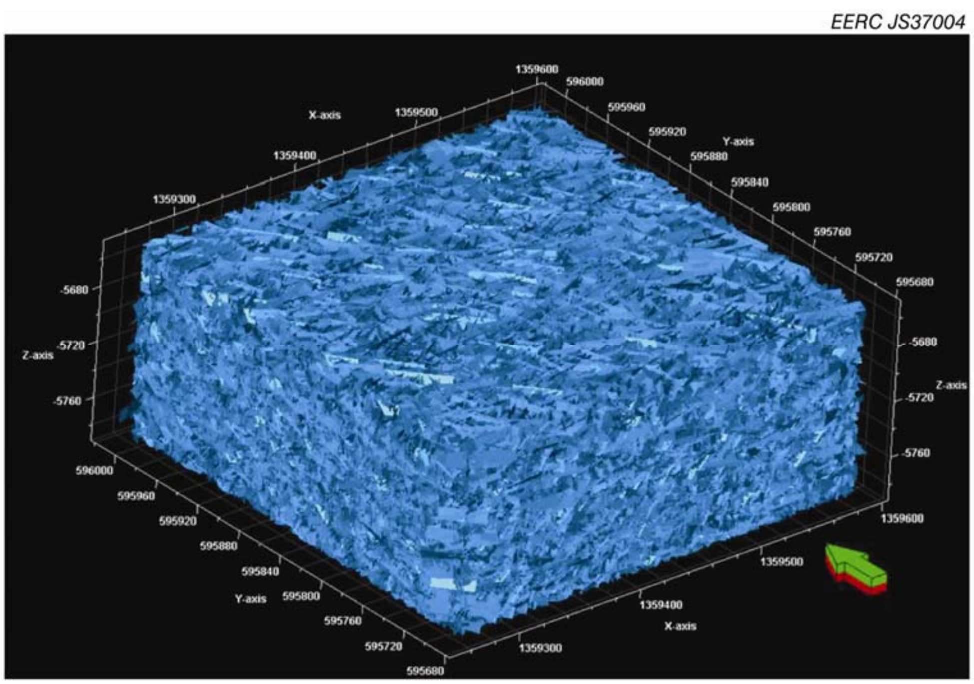

Figure 14. A DFN realization created to be upscaled to a fracture permeability and porosity grid model for the Northwest McGregor reservoir system.

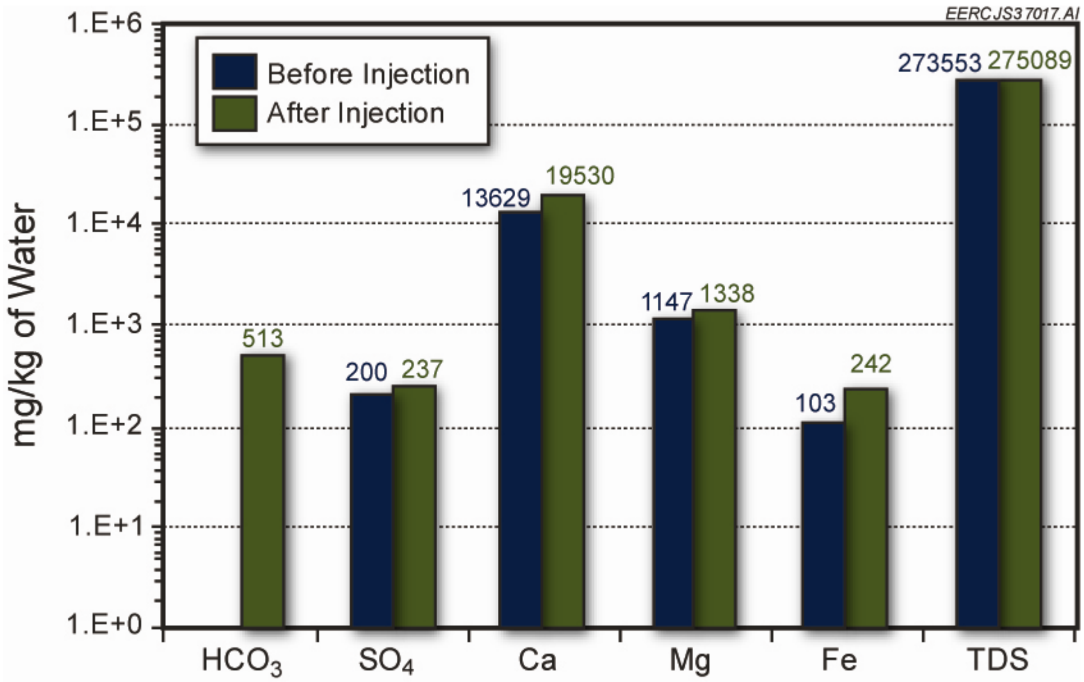

Figure 15. Comparison of selected downhole fluid analytical results from the preinjection period and the postproduction period. Bicarbonate (HCO_3) was not detected in the preinjection downhole fluid sample.

used to predict the effects of CO_2 injection on the geochemical regime of the reservoir. The increases in calcium and bicarbonate suggest that calcite minerals in the Northwest McGregor Reservoir are likely undergoing some degree of dissolution as the limestone reacts with carbonic acid generated by the dissolution of CO_2 in formation water. The effect of such dissolution may actually improve the productive performance of the E. Goetz No. 1 well by improving permeability, at least in the near-wellbore environment. Some portion of the improved productivity observed during the production period of the project may be partially due to this dissolution, although no conclusive data have been generated therein.

- Open-hole geophysical logs

  – Many wells that may be candidates for CO_2 HnP operations, especially in oil fields that have been developed since the 1960s, will have files that may include a variety of open-hole geophysical log data. Open-hole logs that should be sought include, at a minimum, density, neutron, caliper, dipole sonic, and microimaging tool logs. These logs provide key rock property data including porosity, resistivity, general lithology and, to a lesser extent, permeability and geomechanical information. Other specialized geophysical logs, such as the RST, can be used to determine the saturation of various phases (e.g., gas, brine, and oil) within a reservoir and other useful properties. Figures 9, 10, and 12 provide examples of the use of geophysical logs for characterization and representation of key facets within the Northwest McGregor Reservoir and seal system.

- Cement bond and casing integrity logs

  – With respect to CO_2 HnP projects, cement bond and casing integrity logs demonstrate the integrity of the casing and cement of the injection well and provide crucial data regarding such critical HnP design elements as the selection of packers and their optimal placement within the well. Figure 16 is an example of a portion of an ultrasonic integrity (USI) log that was run in the E. Goetz No. 1 well prior to injection. The USI log was also run in the E. Goetz No. 1 well during the postproduction phase. Comparison of the results indicated that after a 2-week soak period and 3 months of production, the injection of 440 tons of CO_2 had little discernible effect on the wellbore integrity of the E. Goetz No. 1 well.

- Drill stem tests (DSTs)

  – DSTs should be run in the zone being considered for the HnP operation. A DST provides information on the type and basic characteristics of fluid in the zone being evaluated and the rates at which those fluids can be produced which, in turn, yields important information on the injectivity of the formation. Pressure data from DSTs can be used to calculate formation pressure, permeability, and the amount of

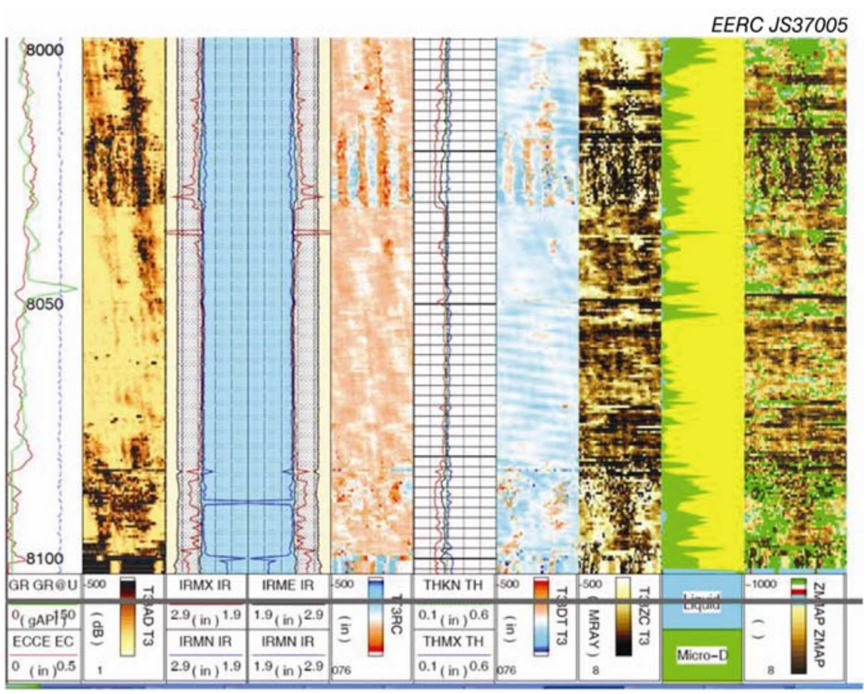

Figure 16. Injection zone portion (interval from 8000 to 8100 ft below ground level) of the E. Goetz No. 1 well USI log run to determine the integrity of the casing and cement of the well prior to injection.

formation damage incurred by the drilling and completion of the well (Hyne, 1991) Historical DST data were available for the E. Goetz No. 1 well, which were used as part of the initial site selection screening process to predict injectivity and productivity.

- Reservoir properties

  The primary reservoir properties that influence injectivity of CO_2 include permeability, hydraulic fracture limitations, reservoir pressure, and well-bore damage or "skin." Various techniques can be applied to measure reservoir properties and estimate or design the equipment required for injection. An injectivity test is a procedure conducted to establish the rate and pressure at which fluids can be pumped into the treatment target while maintaining a pressure below a permitted fracture pressure. The components of an injectivity test are discussed below:

  – Fracture pressure is the pressure above which injection of fluids will cause the rock formation to fracture hydraulically. Typically, injection permits will require a determination of fracture pressure which can be estimated or measured. Estimation methods can be found in literature (Ajienka et al., 2009; Postler, 1997). An estimation equation from Hubbert and Willis (1957) relates fracture pressure to horizontal stress:

    $F = (1/2 \text{ to } 1/3)*(S-P) + P$

    F = Fracture Pressure
    S = Overburden Stress
    P = Pore Pressure

    In the case of the E. Goetz well, the estimated fracture pressure is 5375 psi corresponding to a fracture gradient of less than 0.7 psi/ft. Relative to site location, fracture gradients may already be established to determine permitted injection pressures, or further detailed estimations can be determined from petrophysical properties (Ajienka et al., 2009; Postler, 1997).

    In the event that estimated fracture pressures are potentially limiting or fracture pressure data for a particular location is limited; a pressure integrity test (PIT) or "leak-off test" can be completed to measure fracture pressure directly. A PIT is completed by pumping a fluid at a constant rate to produce a typical curve shown in Figure 17. A linear pressure rise is produced as fluid is pumped into the well at a constant rate. A nonlinear pressure rise will result upon fracture initiation and leak-off of fluid into the formation. Point A of Figure 17 is the fracture initiation pressure. The pump is shut off at Point B, and the well is shut in. Point C is the minimum formation stress, and Point D is the fracture closure pressure. Advanced interpretations of PIT are required to limit misinterpreted pressure plots (Postler, 1997).

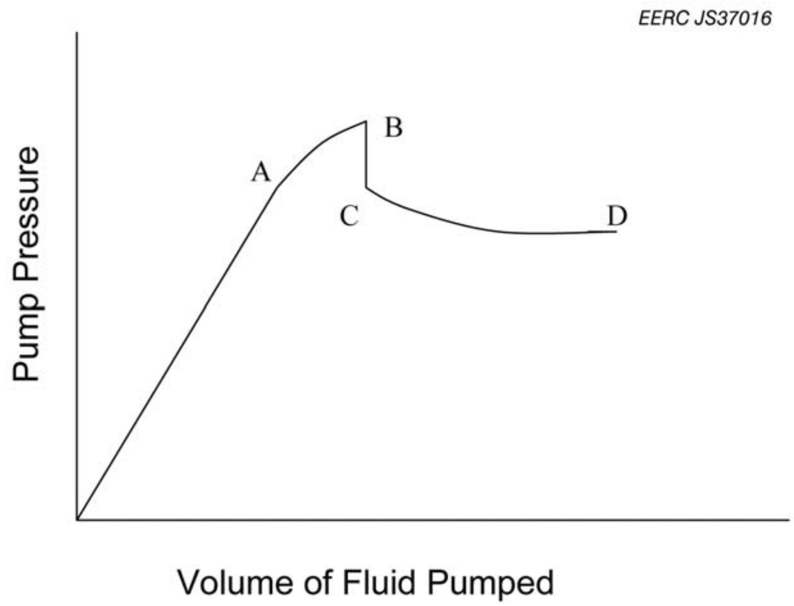

Figure 17. Leak-off test pressure curve.

– Reservoir pressure is the pressure of the formation at the completed interval depth. Reservoir pressure is commonly measured by inserting a bottom-hole pressure gauge surveying pressure for a period of 48–72 hours. The results of a pressure survey conducted in the E. Goetz No. 1 well at reservoir depth indicated a reservoir pressure of 2600 psi.

– Pressure transient analysis (PTA) is used to determine reservoir properties such as permeability and skin. Low reservoir permeabilities can greatly reduce the rate of injection where adequate injection rates are required to economically develop geological sequestration projects for CO_2. A related property known as "skin" provides an indication of formation damage that can occur in the near wellbore where fluids move from the well through perforations in the casing and into the reservoir formation. A negative formation skin factor is an indication that fluids can move easily from the wellbore to the formation, and a positive skin indicates resistance to fluid movement in the near wellbore location. Examples of various PTA that can be used to determine permeability and skin include pressure buildup, drawdown, and injection falloff. Types of well testing that use PTA include drill stem test, slug test, and diagnostic fracture injection. The EERC utilized a method of pressure buildup in the E. Goetz well combined with 1960 vintage drill stem test data to estimate the permeability and skin of the formation. The results are provided in Table 3.

– Injectivity was estimated using the General Darcy Flow Equation based on the properties in Table 3. The results suggested that injection of 0.5 to 2 bbl/min would be possible at surface treating pressures of 1500–3000 psi. Surface treating pressure

Table 3. Key Data Derived from the Pressure Transient Analyses Conducted on the E. Goetz No. 1 Well During the Preinjection Phase of the Project

Reservoir Pressure	2600–2700 psi
Permeability Range	0.3–30 mD
Skin Factor	–3 to +3
Fracture Initiation Pressure	~5400 psi

would be maintained below 3000 psi to avoid exceeding the fracture gradient, and current skin factor did not appear to be limiting. The calculated results were further compared to literature where similar treating pressures and flows were obtained. The corroboration of results eliminated the need to proceed with further well testing to estimate injectivity. Injectivity is calculated by dividing the flow rate by the difference of bottom-hole injection pressure and formation pressure. The measured performance was 3168 bbl/day / (5100 psi – 2600 psi) = 1.27 BPD/psi, with 5100 psi representing the bottom-hole pressure during injection.

Direct measurement of injectivity can also be obtained from an injection pressure buildup test. Initially, the well is shut-in, and a stabilized bottom-hole pressure is obtained. Injection begins at a fixed rate while bottom-hole pressure builds and eventually levels off. The data are analyzed to provide permeability, skin, pressure drop due to skin factor, and injectivity or flow efficiency. Injectivity is normally conducted by injection water into oil reservoirs; however, nitrogen may be applied. Nitrogen fracture injection tests (NFIT) can be applied to gain similar data with a minimal amount of injected fluid. NFIT data are evaluated to produce permeability, skin, fracture half-length, fracture closure pressure, reservoir pressure, and relative injectivity of nitrogen.

PREDICTING THE MOVEMENT AND FATE OF INJECTED CO_2

Dynamic Injection Modeling

Dynamic modeling of the fate of 440 tons of CO_2 injected into the E. Goetz No. 1 well and the Mission Canyon Reservoir was conducted over the course of the Northwest McGregor HnP operation. Dynamic modeling is an iterative process, with each iteration building upon the data obtained from field and laboratory-based activities that were conducted over the course of the project. For instance, the earliest petrophysical models, which were created before the initial RST and VSP characterization work and fracture analysis studies were completed, did not take into account the heterogeneous geometry and distribution of the fracture network but, rather, distributed the effective permeability values that had been calculated by DST and PTA data in a relatively homogeneous manner. This resulted in a predicted CO_2 plume that was very uniform and circular in shape (Figure 18).

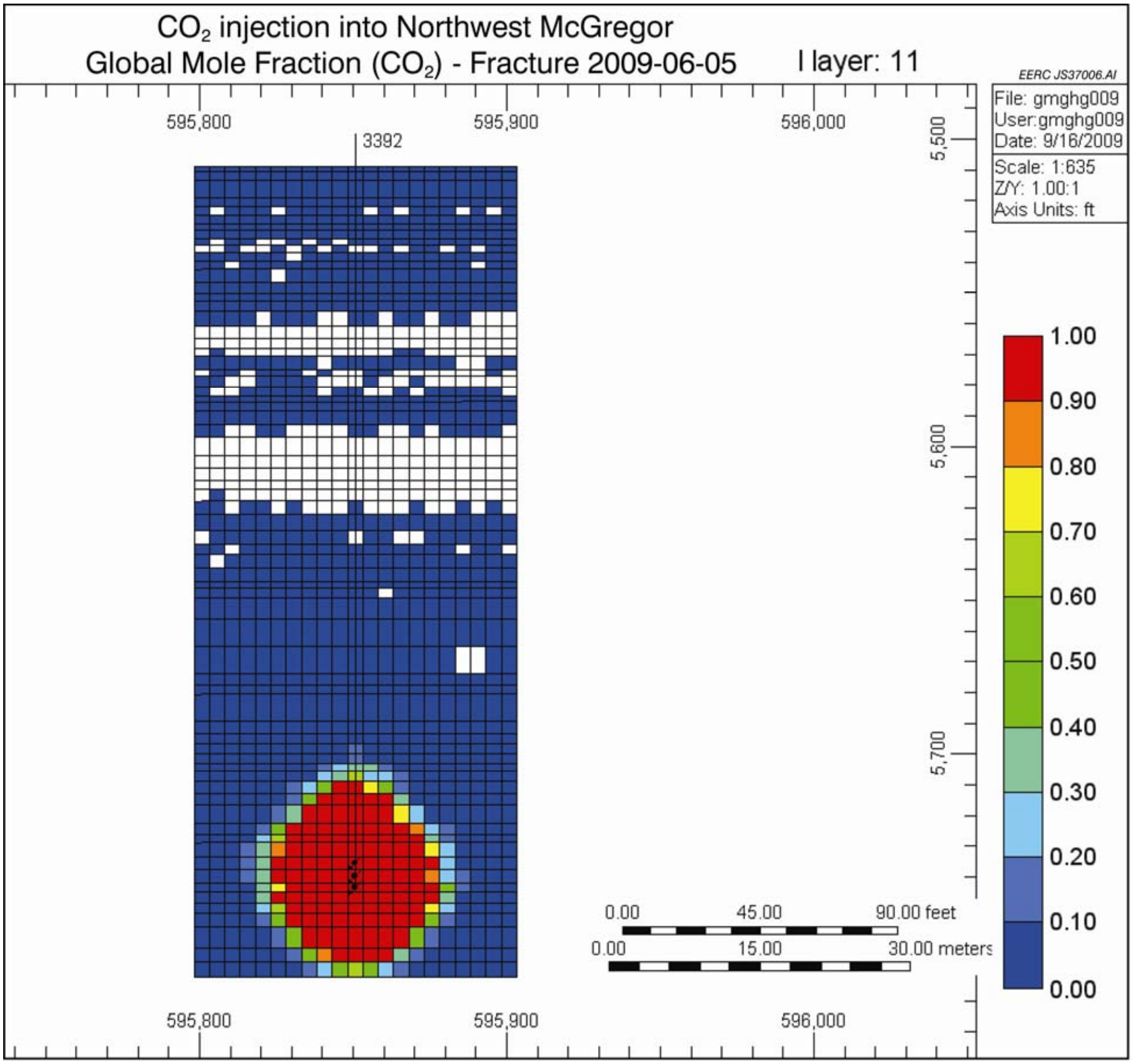

Figure 18. Results of the initial CO_2 injection simulation as represented by a cross-sectional view of the CO_2 plume 30 days after injection is complete. The colors represent saturation of CO_2 within the reservoir.

As more data became available from both the laboratory-based petrographic characterization of core samples and the preinjection field-based characterization efforts (particularly from the downhole fluid analysis, RST, and VSP), the static petrophysical model was refined to more accurately reflect the geological and geochemical conditions of the Northwest McGregor Mission Canyon Reservoir in the vicinity of the E. Goetz No. 1 well. This, in turn, provided the basis for injection simulations that were likely more accurate in their predictions of CO_2 movement. However, the results of the fracture analysis studies were still not available at this point of the project, and the second iteration of modeling still did not fully consider the complex nature of fracture density within the reservoir system and the effects that such fracture distribution would have on plume geometry. Figure 19 presents one representation of the results of the second iteration of injection simulation modeling.

A third iteration of injection and production simulation modeling was conducted in the fall of 2009, which was able to incorporate the results of the final postproduction suite of field-based characterization activities (downhole sample analysis, RST, and VSP), the results of the fracture analysis studies and fracture network modeling, and the fluid production data. This allowed for the further refinement of the petrophysical model to include a more thorough understanding of the geochemical regime, distribution of oil, gas, and water saturation within the reservoir and, perhaps, most importantly, a more accurate representation of the distribution and geometry of the fracture networks that appear to control the movement of fluids within the Northwest McGregor reservoir. The effect that application of the fracture network within the geological model can have on injection dynamics is demonstrated in Figure 20, which shows the simulated distribution of 440 tons of CO_2 in the reservoir rock matrix (i.e., primary porosity) as compared to its distribution in the reservoir fracture network. This demonstrates the magnitude of the impact that the vertical fracture network has on the effectiveness of the CO_2 HnP in the Northwest McGregor Mission Canyon Reservoir. It also underscores the importance of the inclusion of detailed production, petrographic, lithologic, geomechanical, and geochemical data in dynamic simulation modeling.

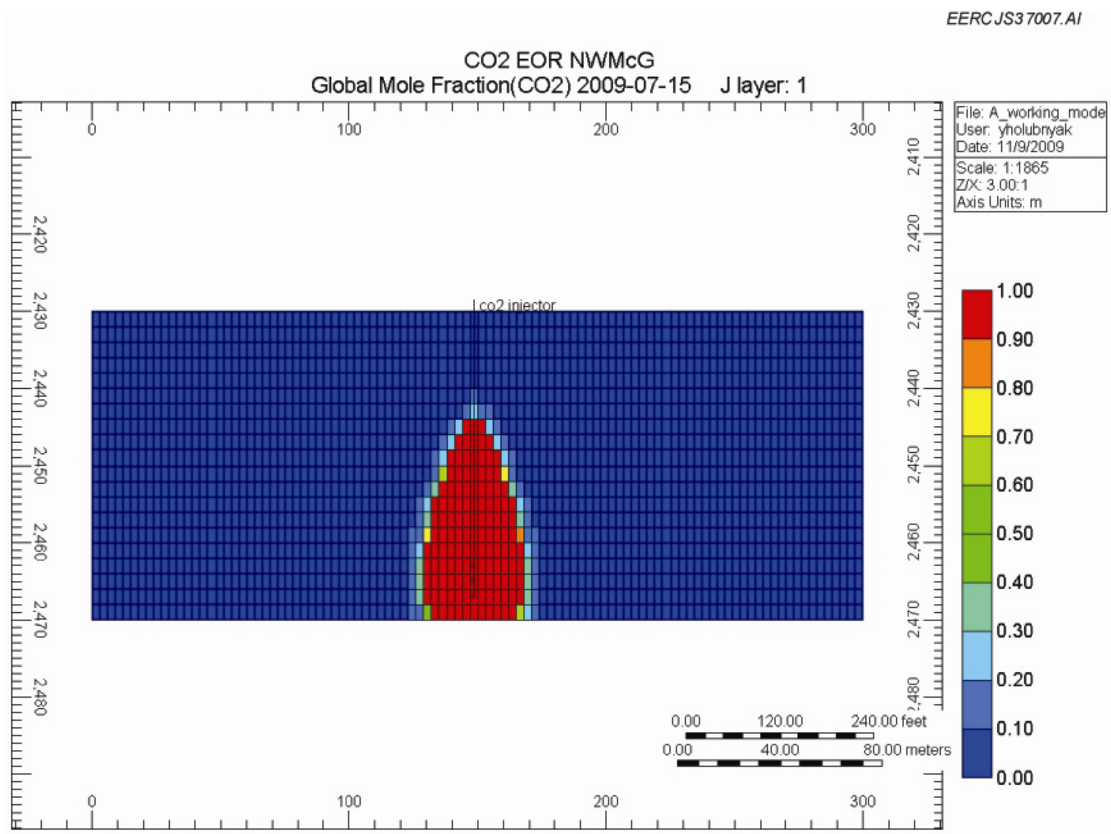

Figure 19. Results of the second iteration CO_2 injection simulation as represented by a cross-sectional view of the CO_2 plume 30 days after injection is complete. The colors represent saturation of CO_2 within the reservoir.

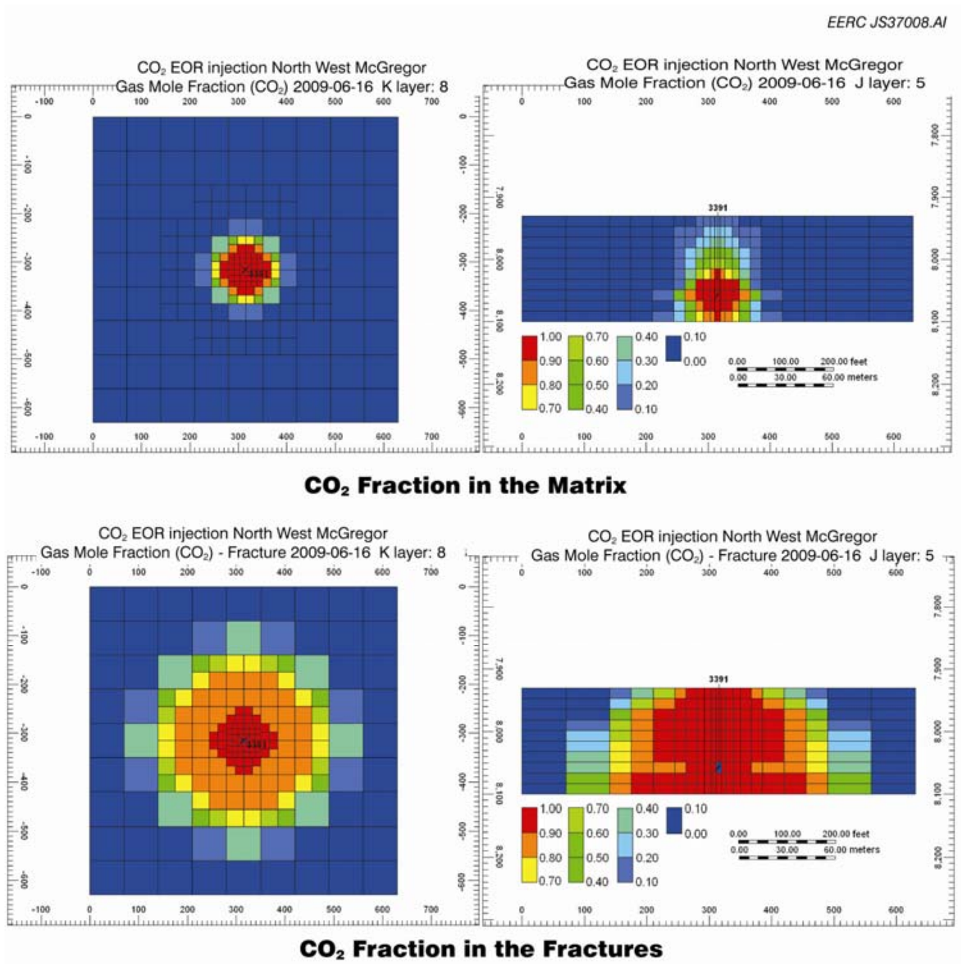

Figure 20. Map and cross-sectional views of simulated CO_2 plume fraction distribution within the reservoir (above) and fracture network in the Northwest McGregor Mission Canyon Reservoir. The colors represent saturation of CO_2 within the reservoir.

CO_2 INJECTION AND OIL PRODUCTION – THE KEY ELEMENTS OF THE HnP

Injection of CO_2 for the Northwest McGregor HnP Test

Using screening criteria for CO_2 HnP operations described by Mohammed-Sing et al. (2006) and HnP injection design principles presented by Patton et al. (1982), it was estimated that an injection volume of approximately 400 tons would be appropriate for achieving the goals of the Northwest McGregor project. Major factors considered in that estimate include reservoir permability, pressure, and temperature. The injection of CO_2 into the Mission Canyon Reservoir of the Northwest McGregor oil field was initiated on June 25, 2009, and completed on June 26, 2009. The total amount of CO_2 injected was 440 tons, and the time required to inject that volume was 36 hours. The operational parameters of the injection are provided in Table 4. The CO_2 used in the injection was of a food- grade purity (>99% CO_2). It was purchased from Praxair, which shipped it by rail from its gas plant in Wyoming to a rail yard in Stanley, North Dakota, from

Table 4. Operational Parameters for the Injection of CO_2 into the E. Goetz No. 1 Well

Total Mass of CO_2 Injected	440 tons
Maximum Allowable Injection Pressure Based on Fracture Gradient	5375 psig
Average Injection Rate	12.2 tons/hour
Average Injection Pressure (surface)	2200 psig
Average Injection Pressure (bottomhole)	5000 psig
Average Injection Temperature (bottomhole)	180°F
Wellhead Pressure at End of Injection	2800 psig
Length of Injection Period	36 hours

which it was then transported by tanker truck to the Northwest McGregor injection site. The pumping unit and technical support to conduct the injection were also provided by Praxair. Figure 21 is a photograph of the pumping unit that was used to pressurize the CO_2 and the piping and valves system that was used to deliver the pressurized CO_2 to the wellhead. The pressure of the CO_2 was maintained in a manner to ensure the CO_2 was injected into the reservoir in the supercritical state but did not exceed the reservoir fracture pressure. Upon completion of the injection, the E. Goetz No. 1 well was shut-in.

Production of Oil from the Northwest McGregor HnP Test

Injected CO_2 was allowed to soak for a period of 2 weeks after injection. The soak period allows the injected CO_2 time to dissolve into the oil, causing it to simultaneously expand and

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Figure 21. Pumping unit and pipe and valve system used to inject CO_2 into the E. Goetz No. 1 well.

undergo a reduction in viscosity, which in turn allows it to flow more freely. Oil recovery is also stimulated by the localized increase in reservoir pressure that was caused by the injection operation. On July 6, 2009, the E. Goetz No. 1 well was opened to determine if the well was ready to be brought back onto production. Literature indicates that the standard operating procedure for determining adequate soak time is to observe the initially produced fluids. If the CO_2 has had adequate time to soak, then oil and water production is expected within the first 24 to 48 hours. If only CO_2 is produced within the first 24 to 48 hours, then additional soak time is required to allow enough time for CO_2 to become miscible with the reservoir fluids.

In the case of the Northwest McGregor HnP operation, the E. Goetz No. 1 well produced exclusively gas for approximately 2 hours before producing oil and water at a rate approximately 10 times greater than baseline. This relatively high production, with a peak production rate of 20 barrels of oil per day, occurred initially during a period of free flow (i.e., not on any type of pump). Oil and water production was initially flowed into a portable 3-phase separator. The 3-phase separator was sized to handle the higher rates of production anticipated during initial flow back. A page pump was installed on July 9, 2009, and the well put on pump. Unfortunately, the installation of the pump restricted the free 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 return to the 20 bbl/day range. Figure 22 is a graph showing oil and water production over the course of the production period (July 6, 2009 through November 10, 2009). Tables 5 and 6 provide key production statistics for the same period of production.

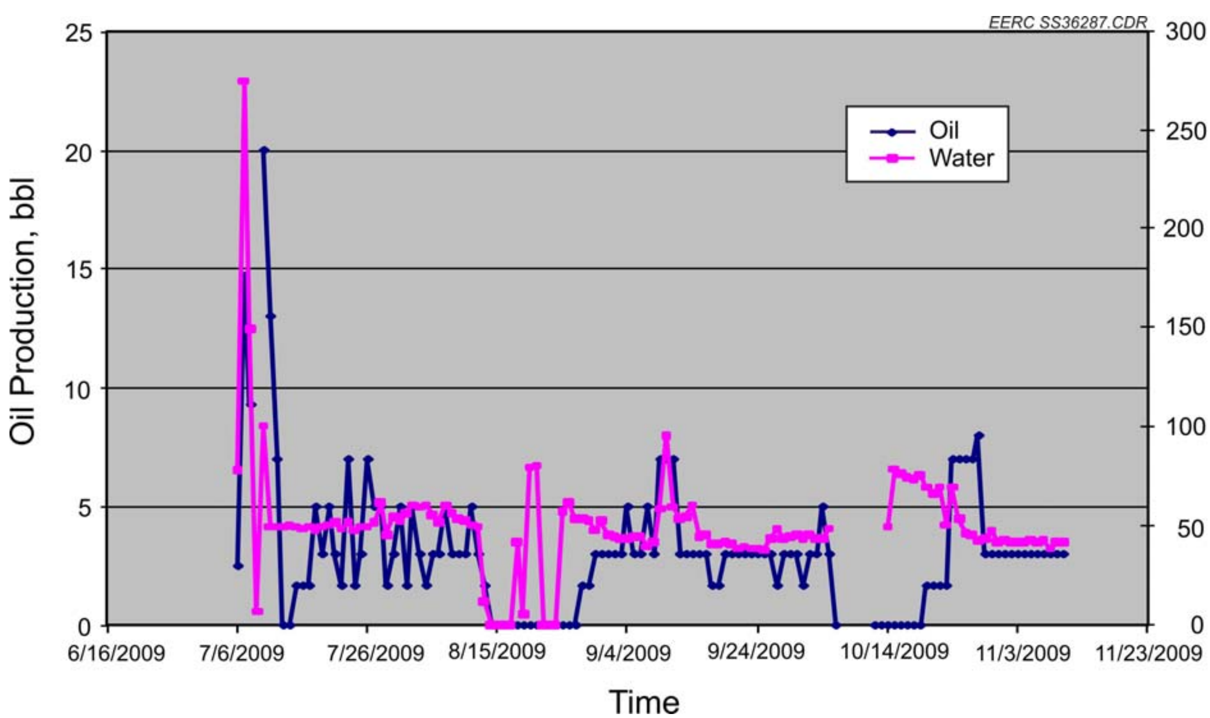

Figure 22. Oil and water production data for the Northwest McGregor HnP, summer and fall 2009.

Table 5. 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	2.2X
Oil Cut	2.8 %	6%	2.1X
% of Injected CO_2 Produced Back	NA	30%	NA

Table 6. Production Totals for the Northwest McGregor HnP Operation from July 6 Through November 10, 2009

Days on Production	Oil	Water	Gas
115	377 bbl	6100 bbl	2222 Mcf (130 tons)

From a technical standpoint, the CO_2 HnP did result in improved oil recovery as compared to baseline production rates. Both the oil production rate and the oil cut for the E. Goetz No. 1 well were, on average over the 115 days of the Phase II project production period, more than double the preinjection values of those parameters. Based on what was learned from the geological characterization activities, it appears the vertically fractured nature of the Northwest McGregor Mission Canyon Reservoir may have limited the immediate improved recovery relative to that which has been reported from other CO_2 HnP projects. Based on the results of the specialized geophysical characterization work, especially those of the RST logging runs, it appears that the CO_2 and oil are largely above and below the perforated zone. The apparently rapid vertical distribution of the CO_2 within the reservoir is almost certainly related to the vertical fracture network. There were no results from HnP projects in fractured reservoirs reported in the reviewed literature, so there is no analog to which the Northwest McGregor HnP can be compared with respect to the effects of fractures on HnP production performance. It appears reasonable to assume that the fracture network may be a complicating factor in the performance of the Northwest McGregor HnP, although the true nature and magnitude of the fracture-related effects are difficult to determine with the current level of data.

MONITORING ACTIVITIES

Surface Pressure Measurements and Fluid Sampling and Analysis Events

Monitoring of the injected CO_2 is a critical component of any CCS project, whether it be a large-scale commercial injection project or a small-scale research-oriented project such as the Northwest McGregor HnP project. While the small volume of CO_2 and the characteristics of the reservoir (particularly with respect to depth and the presence of several confining units above the zone of injection) suggested that there is a very low risk of adversely impacting either neighboring oil wells or shallow subsurface groundwater resources, the Northwest McGregor project did provide an excellent opportunity to demonstrate the application and effectiveness of a variety of monitoring techniques in the field.

Monitoring at the Northwest McGregor field in the vicinity of the E. Goetz No. 1 well was conducted to determine potential impacts to the deep Mission Canyon reservoir environment and the shallow subsurface environment. The E.L. Gudvangen No. 1, a well located approximately ¼ mile southwest of the E. Goetz No. 1 well that actively produces oil and gas from the same interval of the Mission Canyon Formation, was used to monitor for effects on the Northwest McGregor Mission Canyon reservoir outside the intended zone of injection. The shallow groundwater well that was actively monitored was located on residential property approximately ¼ mile to the east of the E. Goetz No. 1 well. Monitoring of the shallow well was conducted to determine baseline water quality conditions and ensure that there were no impacts to groundwater quality as a result of the injection activities. Both the E.L. Gudvangen No. 1 and the shallow groundwater well were sampled periodically for water and gas. The monitoring program also included data logging of the wellhead pressure, temperature, and flow of the production fluids for the E. Goetz No. 1 and E.L. Gudvangen No. 1 wells. Periodic composition analysis was completed for oil, water, and gas for both oil wells. Gas samples from all of the wells were analyzed relative to 1 pound of perfluorocarbon tracer introduced at the beginning of the CO_2 injection. These monitoring activities were conducted to provide a timely and effective means of informing the operator and other potentially affected stakeholders of potential impacts should the injected CO_2 migrate out of the intended zone.

The results of the monitoring activities demonstrated that no statistically significant changes in monitored parameters were observed over the course of the project at the E.L. Gudvangen No. 1 well or the shallow groundwater well. Figure 23 is a graph of CO_2 measurements in gas samples from the E.L. Gudvangen No. 1 well which demonstrates that there has been no change in CO_2 content in the gas stream for that well, while Table 7 presents water quality data from the shallow groundwater well demonstrating no statistically significant change in water quality for those resources. The differences in values for the water quality parameters for the shallow groundwater well fall within the range of variation that may be expected to occur as a result of seasonal influences on groundwater quality (Montgomery et al., 1986).

Sample analyses used to monitor the project site included the following: standard water and oil analysis, titration for determining CO_2 content in water, and light ends hydrocarbon analysis to determine CO_2 content in oil. Gas analysis was performed on-site using infrared analyzers, and gas bags were submitted for gas chromatography.

Use and Evaluation of RST and VSP for CO_2 Monitoring in a Deep Reservoir

The Northwest McGregor HnP test site offered a chance to test two specialized geophysical characterization technologies in a deep carbonate reservoir environment. While the application of these technologies is not a necessary component to the operation of a HnP-based oil recovery project, their use as a means of identifying and qualitatively or semiquantitatively monitoring CO_2 in the context of CCS may be quite appropriate and valuable. The RST and VSP technologies, both owned and operated by Schlumberger Oilfield Services and applied at the

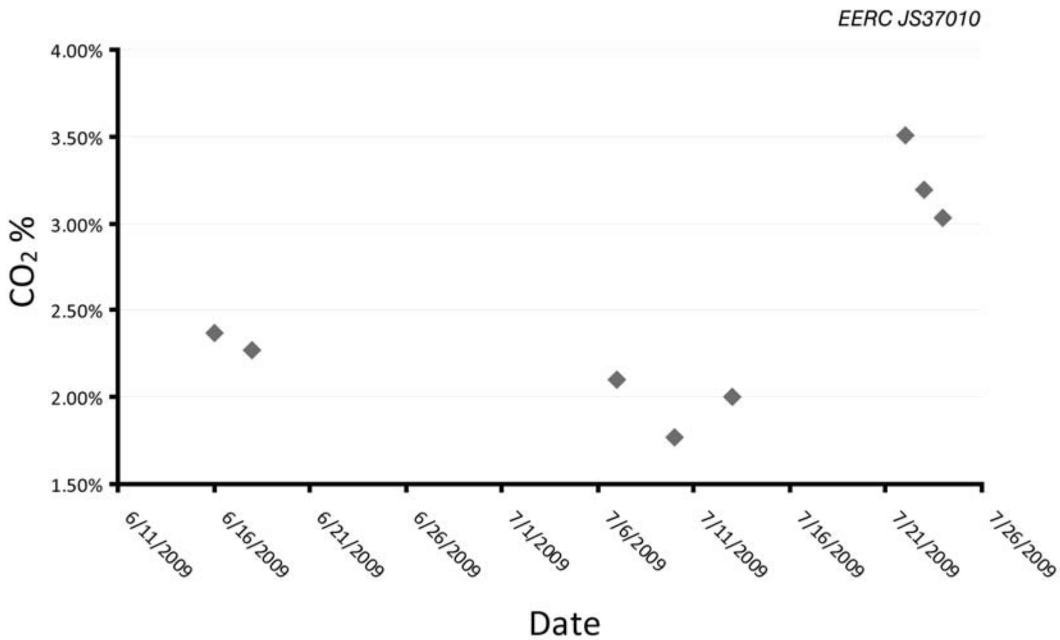

Figure 23. CO_2 content measured in the E.L. Gudvangen No. 1 gas stream.

Table 7. Results of Water Quality Tests on Water from Shallow Groundwater Wells in the Vicinity of the E. Goetz Well

	Before Injection	3 months after Injection
pH	7.4	7.8
Bicarbonate, mg/L	1530	1464
Ca, mg/L	270	248
Total Dissolved Solids, mg/L	4910	5100
Conductivity, ohm-m	1.66	1.74
Perfluorocarbon	No detect	No detect

Northwest McGregor site in close collaboration between Schlumberger Carbon Services and the EERC, 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 carbonate and evaporite beds within the Mission Canyon Formation added a level of complexity to the system that further tested the ability of both the field-based components of the technology and the office-based processing and interpretation of the raw data generated in the field. The relatively small amount of CO_2 injected into the reservoir and small footprint of the plume also tested the 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.

Application of RST at the Northwest McGregor HnP Test

The RST is a downhole geophysical tool that is deployed into the target well using a truck-mounted wireline system. For the E. Goetz No. 1 well, application of the RST took a crew of two people approximately 4 to 6 hours. While the raw RST data for each run were provided to the EERC in the field immediately upon completion, final processing of the raw data into an interpretive format was conducted by Schlumberger personnel in Houston, Texas, over the course of approximately 2 weeks. The RST technology was deployed in the E. Goetz No. 1 well three times over the course of the Northwest McGregor HnP project: 1) approximately 6 weeks 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) at the end of the production phase of the project, 129 days after the well was brought back onto production.

The RST tool was considered appropriate for this application for two significant reasons. First, the small diameter of the tool, 1 11/16 inches, was ideal for deployment within the production tubing of this well. This offered a significant opportunity to log the hole immediately after injection ceased to determine saturations and extent of vertical migration within the reservoir. Second, the cased hole utility of this tool allows for longer-term monitoring of fluid saturations in the near-wellbore environment, which, coupled with VSP findings, can be used in dynamic simulation of reservoir performance and lateral migration of CO_2. Figure 24 shows a comparison of results from those RST logging events.

The results indicate that the 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 7930 ft. Some residual gas saturation appears to have migrated into and remained at levels below the perforated zone. The presence of CO_2 above the perforations during both the soak period and the postproduction period is expected because supercritical CO_2 is buoyant and should naturally migrate upward through the reservoir until it encounters a seal. This phenomenon (upward migration of the injected plume) has been well documented at CO_2 injection sites such as Sleipner, Weyburn, and others. The measurement of CO_2 in relatively high concentrations below the perforated zone was unexpected, as downward migration of CO_2 is not consistent with what has typically been observed at other injection sites. One hypothesis to explain this observation is that the increased reservoir pressure during the injection served to open the vertical fractures. The opening of the fractures combined with the relatively high injection pressure (averaging 5000 psi bottomhole pressure) may have resulted in some of the CO_2 being “pushed” downward into the open fractures. Under this hypothesis, when injection ceased, the fractures closed, thereby trapping a portion of the CO_2 in the lower zone of the reservoir. 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 USI logs,

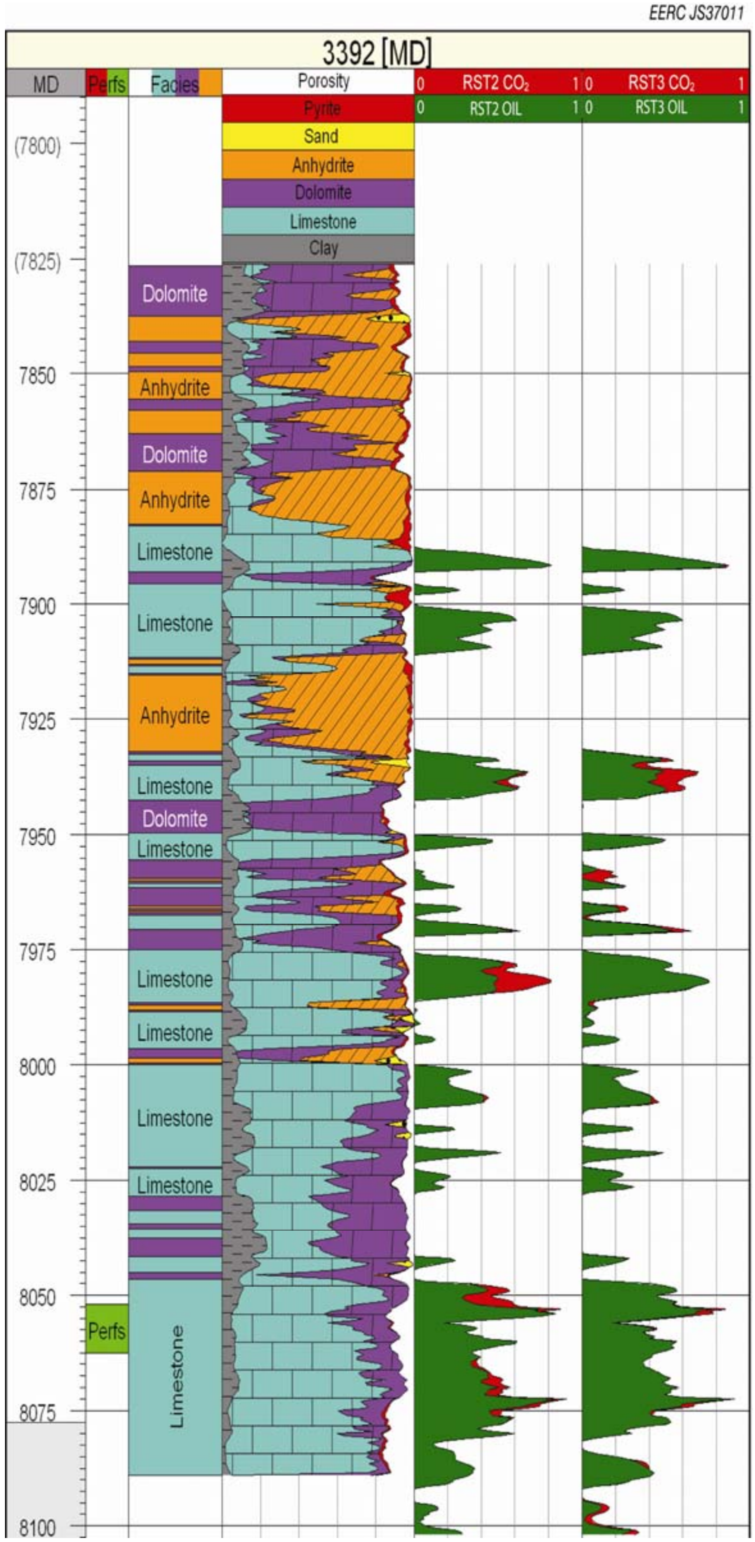

Figure 24. Comparison of results of sequential RST logging events. CO_2 saturation is represented by red, while oil saturation is represented by green.

caliper logs, and other wellbore integrity-related logs, these results may be particularly useful in identifying locations in the wellbore that may act as points of leakage.

Application of the VSP Technology at the Northwest McGregor Field

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 3000 ft 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 and the plume. The survey events required a minimum of a four-person crew and approximately 10 to 12 hours to conduct. The VSP technology was deployed by Schlumberger Carbon Services twice over the course of the Northwest McGregor HnP project: 1) approximately 6 weeks before injection to establish baseline saturations of oil, water, and gas in the reservoir environment and 2) at the end of the production phase of the project, 129 days after the well was brought back into production. Raw data were sent to Schlumberger offices in Houston, Texas, for processing. Largely because of the complex and heterogeneous nature of the carbonate- and evaporite-dominated rocks that make up the Mission Canyon Formation, processing of the raw data into formats that allowed for interpretation required approximately 6 weeks. Figures 25 and 26 provide a comparison of results from those VSP deployment events.

Close examination of the raw VSP data generated by the two surveys showed that there was an observable difference in seismic reflectance in the reservoir between the baseline and postinjection runs. In particular, there was a noticeable difference in the CDP maps for the north and east offsets. The processed VSP results indicated that the lateral component of the injected CO_2 plume spread out primarily in an easterly direction, with CO_2 saturation seen approximately 300 ft from the E. Goetz No. 1 well along the eastern transect and approximately 50 ft along the northern transect. The results indicate that the VSP surveying technology is able to identify the zones into which CO_2 was injected and subsequently migrated a distance of 300 to 1200 ft away from the wellbore. These results indicate that the VSP 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. When interpreted in conjunction with RST logs, these results may be particularly useful in delineating the vertical and horizontal extent of a CO_2 plume. In the case of the Northwest McGregor injection, the VSP results show the plume as largely being at a depth of a little more than 7900 ft, entirely consistent with the RST results showing the greatest saturation of CO_2 at approximately 7930 ft. It is also worth noting that its ability to detect the small amount of CO_2 (approximately less than 300 tons distributed over an area of approximately an acre) that was in the Northwest McGregor Mission Canyon Reservoir after 115 days of production suggests that the VSP may be an effective means of identifying the edge of larger plumes such as would occur at large-scale commercial CCS injection projects.

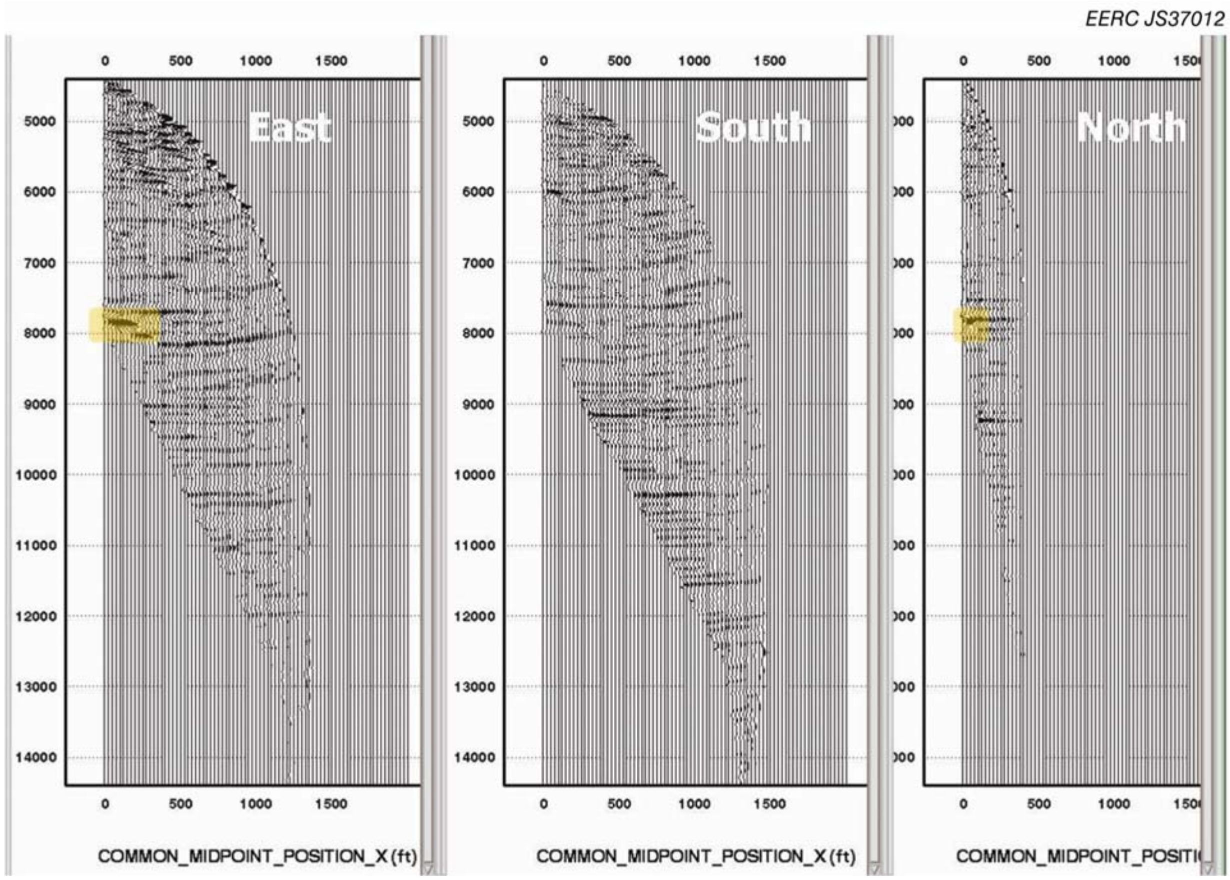

Figure 25. Difference CDP (common depth point) maps showing comparison of results from the VSP surveying events. The areas highlighted in yellow indicate zones that have been interpreted to represent a change in density that is indicative of an increase in CO_2 saturation within that portion of the reservoir.

KEY FINDINGS OF THE NORTHWEST MCGREGOR HnP DEMONSTRATION

The activities conducted at the Northwest McGregor oil field as part of the PCOR Partnership Phase II field demonstration project yielded previously unavailable insight regarding 1) the effective combined use of historical and newly acquired geological, geochemical, and geomechanical data sets to develop the petrophysical and dynamic simulation models necessary to predict and history-match CO_2 injection; 2) the effectiveness of the RST and VSP geophysical characterization technologies to identify and delineate the occurrence of CO_2 in a deep carbonate oil reservoir; and 3) the effectiveness of small-scale CO_2 injection using the HnP approach to stimulate improved oil recovery from a mature oil well in a deep carbonate reservoir. Key findings include the following:

- Regional characterization conducted during the PCOR Partnership Phase I activities indicated that there may be up to 60 billion tons of storage capacity in the carbonate rocks of the Mississippian Madison Group (Fischer et al., 2004). The results of the

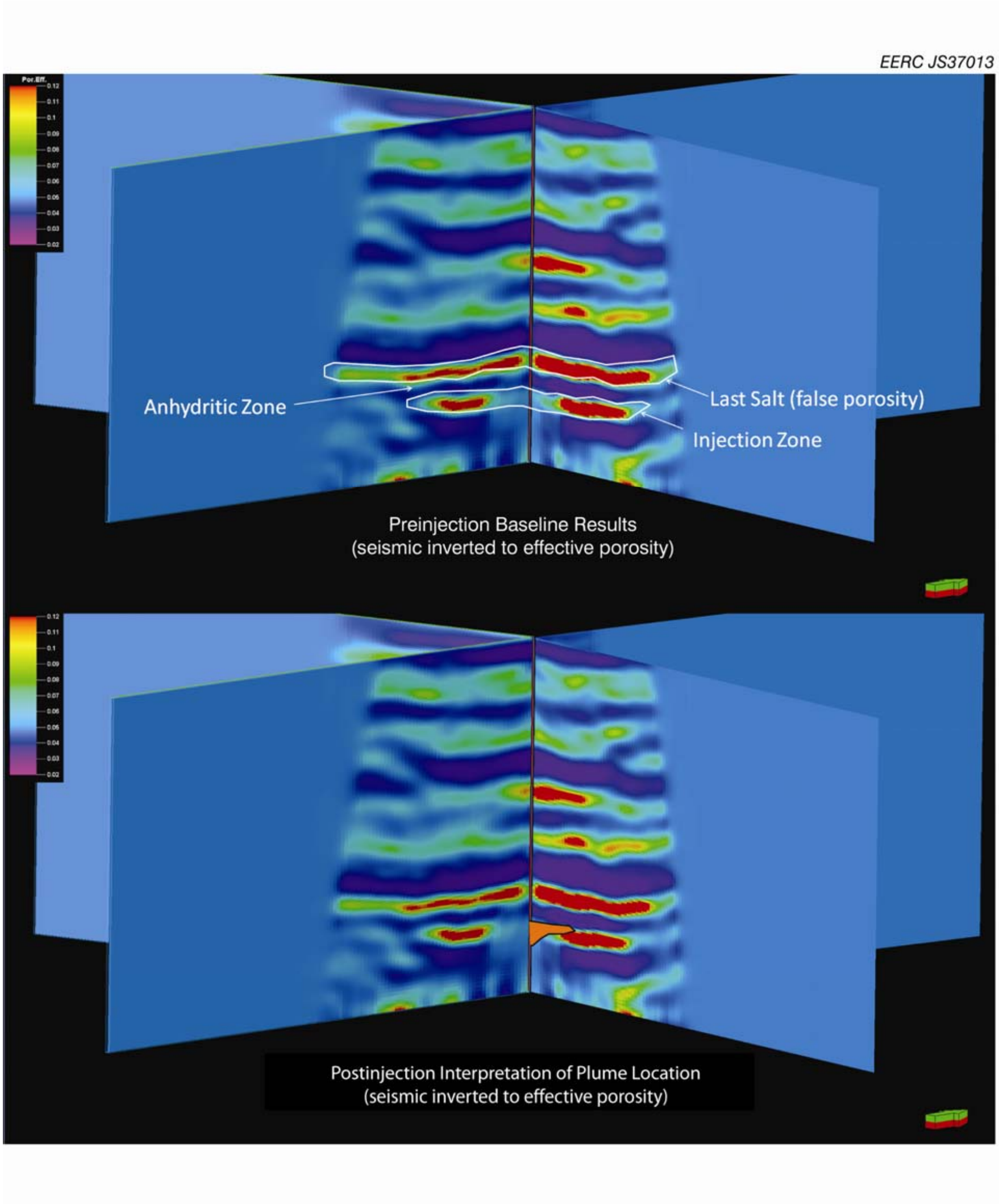

Figure 26. Interpreted comparison of VSP survey pre- and pokstinjection results.

Northwest McGregor field and laboratory efforts provide additional technical data on injectivity, geomechanical integrity, geochemical reactivity, and the applicability of specialized monitor tools that support the future use of deep carbonate formations for CCS.

- The effective and iterative use of historical and newly acquired data sets is critical to the baseline characterization aspect of MVA. This was demonstrated in the Northwest McGregor HnP project through the development and application of new fracture analysis data and fracture distribution models based on thorough evaluation of historical well logs and core samples. These models were critical to understanding the movement of CO_2 within the reservoir and history-matching both the oil production data and the data from the third RST logging event.

- RST and VSP were demonstrated to have the ability to provide valuable views of the specific location of injected CO_2 within a deep carbonate reservoir environment. The application of these tools, combined with robust modeling, may be very effective MVA technologies for CCS in deep carbonate reservoirs.

- The improved oil productivity that was observed during this project suggests that the application of CO_2-based HnP may be a viable approach to improved oil recovery from mature wells in not only the Williston Basin, but other mature oil-producing areas of the PCOR Partnership region. Phase I characterization activities demonstrated that there are many oil fields in the PCOR Partnership region that may be suitable for the application of large-scale CO_2 injection for EOR operations, with those fields having the potential to produce approximately 3.4 billion barrels of incremental oil (Smith et al., 2006). At a price of $70/barrel (price of oil on New York Mercantile Exchange, November 2, 2009), that oil resource is worth over $238 billion. The use of CO_2 for HnP on individual wells in the region may yield additional economically attractive opportunities, making the size of the prize even larger and providing further incentive for the creation of a regionally extensive CO_2 distribution infrastructure.

RELEVANCE OF THE NORTHWEST MCGREGOR HnP TO THE REGIONAL IMPLEMENTATION OF CCS TECHNOLOGY

The PCOR Partnership region includes hundreds of large stationary sources of CO_2, many of which are located in close proximity (within 100 miles) to oil fields that are suitable for CO_2-based EOR operations. The size of the potential oil resource in the PCOR Partnership region that may be associated with CO_2-based EOR is over 3.4 billion barrels of oil (Sorensen et al., 2006). At a price of $70/barrel, this resource could have a value over $238 billion. The size of this economic prize provides a substantial incentive to develop large-scale CCS projects for some of those close-proximity sources. Many, if not most, of the oil fields in the region are in close proximity to saline formations that may also be suitable targets for large-scale CO_2 storage. Under these circumstances, it is logical to envision the implementation of large-scale CCS in the region as developing over the course of two main phases.

In the first phase of CCS implementation, the economic component associated with the sale of incremental oil from CO_2-based EOR projects helps provide some of the capital required to construct the capture, compression, and transportation elements of large-scale CCS. The effectiveness of large-scale CO_2 flood operations in the Williston Basin has previously been, and continues to be, demonstrated at the Weyburn and Midale oil fields in Saskatchewan. The results of the Northwest McGregor HnP project suggest that smaller-scale CO_2-based HnP operations may also be a viable means of improving the oil productivity of mature wells in the PCOR Partnership region, especially the Williston Basin. While the volumes of CO_2 that would ultimately be stored by HnP operations would be relatively small compared to a CO_2-flood, the use of CO_2 for HnP on individual wells may yield further economically attractive opportunities in the region, making the economic prize even larger and providing additional incentive for the creation of a CO_2 distribution infrastructure in the oil-producing areas of the PCOR Partnership region.

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 geographically and stratigraphically adjacent 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. With respect to baseline characterization, the project demonstrated that historical geological, production, and operational information, obtained from the North Dakota NDIC–OGD well file database and the archives of the North Dakota Geological Survey Core Library can provide a tremendous amount of critical data with respect to the baseline conditions of both oil field reservoirs and individual wells. With respect to monitoring, the Northwest McGregor HnP project yielded previously unavailable field-based data on the effectiveness of using Schlumberger's RST and VSP technologies to develop a semiquantitative view of the vertical and horizontal nature of the injected CO_2 within a deep carbonate reservoir. The ability of these technologies to "see" the effects of the small-volume plume of CO_2 (<300 tons) at a depth greater than 8000 ft, as demonstrated at the Northwest McGregor field months after injection, indicates that these technologies should be considered to be valuable additions to the MVA toolbox for future large-scale CCS projects.

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APPENDIX A

REGULATORY PROCESS FOR HUFF 'N' PUFF IN NORTH DAKOTA

REGULATORY PROCESS FOR HUFF 'N' PUFF IN NORTH DAKOTA

While the regulatory process for any given CO_2 injection project, whether it be for small scale huff 'n' puff (HnP), large-scale enhanced oil recovery (EOR), or carbon capture and storage (CCS), will vary depending on the jurisdiction within which the project is operated, it is instructive to briefly summarize the process that Eagle Operating went through for the Northwest McGregor HnP operation. As an operator, Eagle Operating was committed to conducting the HnP operation on the E. Goetz No. 1 well in a manner that complies with all current North Dakota Industrial Commission – Oil and Gas Division (NDIC–OGD) regulations. Well workover activities, CO_2 injection operations, and the deployment and application of downhole logging and surface seismic equipment were all conducted within industry-recommended practices, including the practices and standards of the American Petroleum Institute (API). In many cases, these standards and practices are consistent with regulatory requirements and guidelines, although it is important that this be determined definitively by the operator early in the planning stages for any CCS project.

To conduct a small-scale CO_2-based HnP operation on an existing oil well in North Dakota, a formal application must be made to the NDIC–OGD under Section 43-02-09-04 of the North Dakota Administrative Code (www.legis.nd.gov/information/rules/admincode.html). In the case of the E. Goetz No. 1 HnP, the small scale of the injection (less than 1000 tons) resulted in a determination by the Director of the NDIC–OGD that the operation fell under the category of a workover project. As such, only a sundry notice (NDIC–OGD Form 4) was required to be submitted for approval by the Director of the NDIC–OGD. No formal public hearing on the matter was required. The completed Form 4 was submitted by Eagle Operating to the NDIC–OGD on February 26, 2009, and formal approval was granted on March 27, 2009. The relevant regulations related to workover projects in North Dakota, under which the HnP operation was regulated, as well as a blank Form 4 and a copy of the Form 4 submitted for the E. Goetz No. 1 HnP are provided in Appendix A.